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

June 30, 2020

Via Electronic Mail

Public Utility Commission of Oregon
Attn: Filing Center
PO Box 1088
Salem, OR 97308-1088

RE: PGE 2019 Annual Report and 2019 FERC Form 1

Enclosed for filing are PGE's 2019 Annual Report, and 2019 FERC Form 1. The e-filed portion of the filing includes:

- PGE's 2019 Annual Report and
- PGE's 2019 FERC Form 1

Sent on CDs via U.S. mail:

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

Not included are five printed copies of PGE's 2019 Annual Report. PGE provides this information to Shareholders in electronic format only. The link to the Annual Report is provided below.

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

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

Sincerely,

/s/ Jaki Ferchland
Jaki Ferchland
Manager, Revenue Requirement

JF/np
cc: Marianne Gardner, OPUC

e-FILING REPORT COVER SHEET

COMPANY NAME: Portland General Electric - Annual Reports for the year ending December 31, 2019

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

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

Did you previously file a similar report? ☐ No ■ Yes, report docket number: RE 54 (8)

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

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

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

1) PGE's 2019 FERC Form 1; PGE's 2019 Oregon Supp to FERC Form 1; and PGE's 2019 Annual Report to Shareholders

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

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

Print

Portland General Electric

2019 ANNUAL REPORT

To our shareholders

This past year marked a decade of continuous change in the energy industry. Over the course of 2019 we made significant progress in transforming our business to provide customers with exceptional service, system resiliency and the clean energy they increasingly demand.

At the same time, we delivered strong financial performance and accelerated investments to enhance the health of our system and to establish a solid foundation for the fully integrated smart grid of the future.

PGE's service area continues to thrive as economic conditions in Oregon remain strong. The state's unemployment rate of 3.2% is below the national average of 3.5%.[1] Oregon is ranked 10th in the country for the rate of net in-migration,[2] contributing to an increase in retail customers to a total of 895,000. We continue to see strong growth in high-tech, which contributed to a 6.7% increase in industrial deliveries.

STRATEGIC ACCOMPLISHMENTS

Operationally, our generation facilities and power operations outperformed expectations, meeting the challenges of lower than expected wind and hydro energy production. We also improved resiliency and elevated our clean energy goals. We delivered exceptional customer service while expanding partnerships and community engagement.

We continue to reduce carbon emissions in our power supply portfolio, including our partnership with NextEra Energy Resources on the nation's first major renewable energy facility to integrate and co-locate wind and solar energy generation with battery storage. Additionally, our Green Future Impact program launched and 17 large customers and municipalities committed to 160 MW in just over three minutes. These efforts complement our 2019 Integrated Resource Plan, which includes proposals to add 150 average MW of new renewable resources and expand flexible load programs and new clean technologies in support of grid reliability.

Customer satisfaction is strong and PGE again rated in the top decile among business and residential customer groups.[3] We remained the No. 1 voluntary renewables program in the country for the 10th straight year, with participation surpassing 25% of customers in 2019.

We filed our Transportation Electrification Plan with the Oregon Public Utility Commission and opened four new Electric Avenue charging hubs in our service area. Our partnership with Oregon's largest transit system, TriMet, deepened to expand electrification of mass transit and to introduce the country's first wind-powered bus line.

We broke ground on our state-of-the-art Integrated Operations Center, a $200 million investment in a facility that centralizes key operations and functions with enhanced technology and resiliency against seismic, cyber and physical security risks. We also moved ahead with engineering and construction on our Field Area Network infrastructure and launched our first-of-its-kind Smart Grid Test Bed project in three Oregon communities, setting a foundation for advancing our ongoing integrated grid initiatives.

1. PGE-3 County Average, December 2019, Source: State of Oregon Employment Department
2. State of Oregon Employment Department
3. Escalant, formerly Market Strategies International

FINANCIAL PERFORMANCE

We delivered strong performance in 2019 with net income of $214 million, or $2.39 per diluted share. Total shareholder return was 25%, including dividends of $1.50 per share.

Full-year earnings guidance for 2020 is $2.50 to $2.65 per diluted share with future earnings guidance growth of 4 to 6%, on average.

LOOKING FORWARD

PGE exists to power the advancement of society. In 2020, we remain committed to serving customers with competitive energy options and service, and top-quartile system reliability. As we mark the closure of our Boardman coal plant by the end of the year, we remain committed to helping customers and the communities we serve achieve a clean energy future.

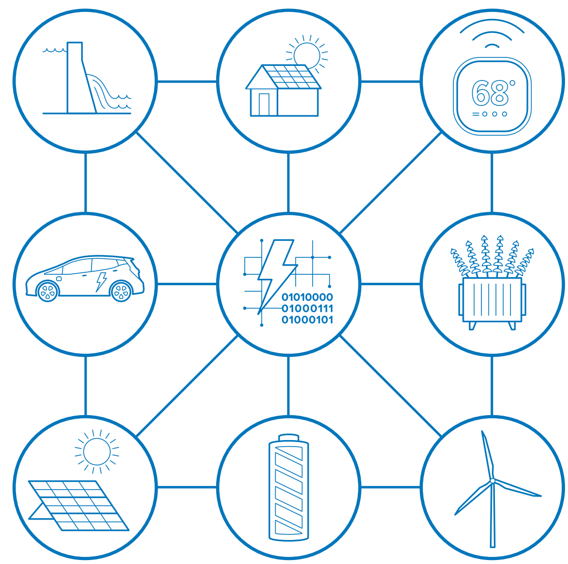
Nearly 3,000 dedicated employees make serving our customers possible. While continued investment in a smart, integrated grid and renewable energy invites change, we remain steadfast in our commitment to operational excellence and keeping the customer at the center of everything we do.

In closing, I would also like to acknowledge that this year marked the retirement of Bill Nicholson, who served PGE for 39 years, including 12 as a member of our Officer team. We also thanked David Dietzler for his dedication and more than 13 years of service to our board of directors. I would also like to welcome Marie Oh Huber, who joined PGE's board of directors in Q2 of 2019. She brings extensive expertise in technology and corporate governance. She has been and will continue to be an asset for our company in the years ahead.

Maria M. Pope

President and Chief Executive Officer

INTEGRATED OPERATIONS CENTER



A $200 million state-of-the-art facility expected to come online in late 2021.

- **Advances** our integrated grid strategy
- **Strengthens** seismic resilience, cyber and physical security
- **Improves** optimization of distributed assets and carbon-free energy

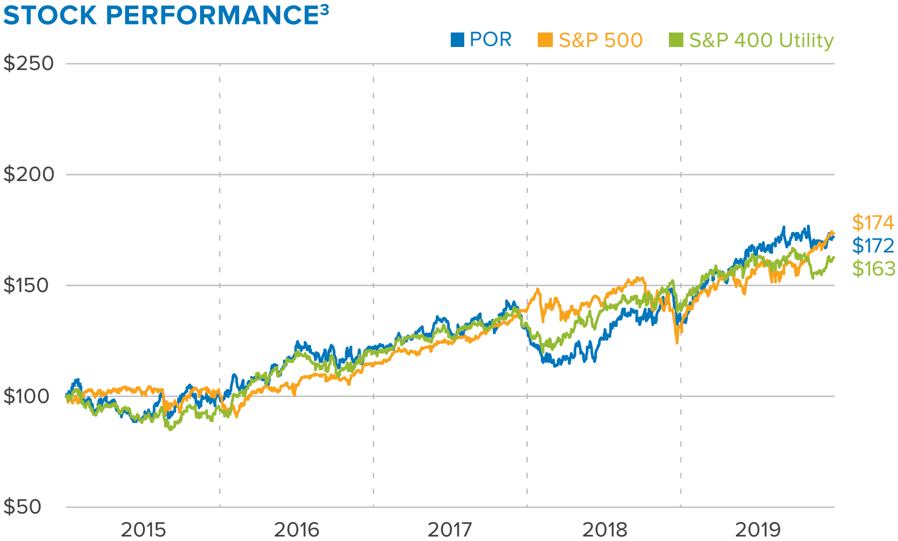
Financial highlights

ABOUT PORTLAND GENERAL ELECTRIC

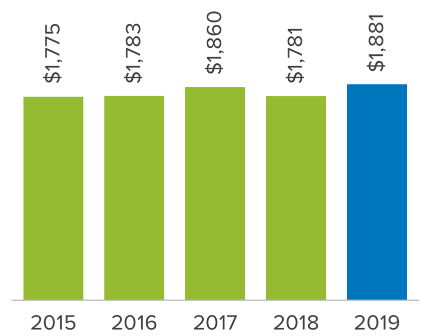
Portland General Electric Company, headquartered in Portland, Oregon, is a fully integrated electric utility serving approximately 895,000 retail customers in Oregon. PGE common stock is traded on the New York Stock Exchange under the ticker symbol POR.

(Dollars in millions, except per-share amounts)	2019	2018	2017
Operating revenues	$2,123	$1,991	$2,009
Net operating income	$353	$346[1]	$380
Net income for common stock	$214	$212[1]	$187[2]
Earnings per share, diluted	$2.39	$2.37[1]	$2.10[2]
Return on average equity	8.4%	8.6%	7.9%
Dividends declared per common share	$1.5175	$1.4275	$1.340
Weighted-average shares outstanding (in thousands), diluted	89,559	89,347	89,176
FOLLOWING DATA AS OF YEAR-END			
Total assets	$8,394	$8,110	$7,838
Long-term debt, including current portion	$2,597	$2,478	$2,426
Long-term debt/capitalization	51.9%	50.2%	50.6%
Senior secured debt ratings (S&P/Moody's)	A/A1	A/A1	A-/A1
Commercial paper ratings (S&P/Moody's)	A-2/P-2	A-2/P-2	A-2/P-2
Customers	895,000	885,000	875,000
Employees	2,949	2,967	2,906

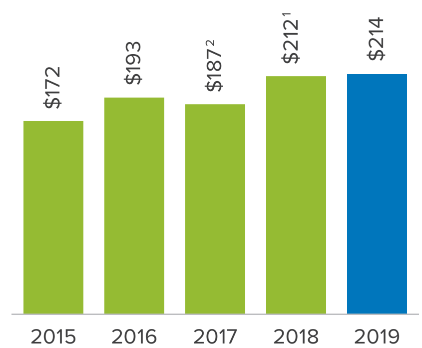
STOCK PERFORMANCE[3]



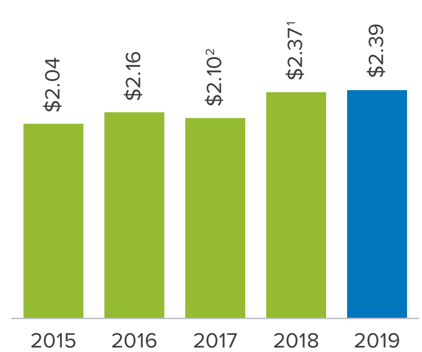
TOTAL RETAIL REVENUE



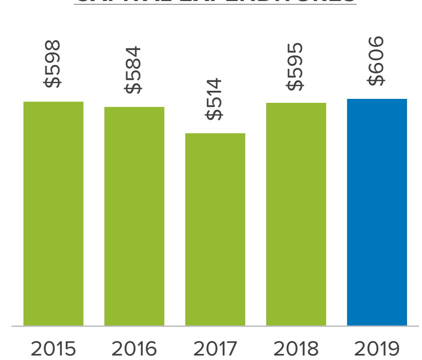
NET INCOME



EARNINGS PER SHARE (DILUTED)



CAPITAL EXPENDITURES



1. Amounts reflect the portion of the $130 million Carty cash settlement proceeds recognized in earnings, $10 million and $0.07, respectively.
2. Non-GAAP net income and diluted earnings per share excluding the effects of the federal Tax Cuts and Jobs Act was $204 million and $2.29, respectively.
3. The chart above assumes a $100 investment in Portland General Electric's common stock and each index on Dec. 31, 2014, and that all dividends were reinvested.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2019

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition period from ______ to ______

Commission File Number 001-05532-99

PORTLAND GENERAL ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

Oregon	**93-0256820**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

121 S.W. Salmon Street
Portland, Oregon 97204
(503) 464-8000
(Address of principal executive offices, including zip code,
and Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

(Title of class)	(Trading symbol)	(Name of exchange on which registered)
Common Stock, no par value	POR	New York Stock Exchange
9.31% Medium-Term Notes due 2021	POR 21	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of June 30, 2019, the aggregate market value of voting common stock held by non-affiliates of the Registrant was $4,823,580,272. For purposes of this calculation, executive officers and directors are considered affiliates.

As of February 4, 2020, there were 89,391,379 shares of common stock outstanding.

Documents Incorporated by Reference

Part III, Items 10 - 14	Portions of Portland General Electric Company's definitive proxy statement to be filed pursuant to Regulation 14A for the Annual Meeting of Shareholders to be held on April 22, 2020.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2019

TABLE OF CONTENTS

DEFINITIONS

The abbreviations or acronyms defined below are used throughout this Form 10-K:

Abbreviation or Acronym	Definition
AFDC	Allowance for funds used during construction
ARO	Asset retirement obligation
AUT	Annual Power Cost Update Tariff
Beaver	Beaver natural gas-fired generating plant
Biglow Canyon	Biglow Canyon Wind Farm
Boardman	Boardman coal-fired generating plant
BPA	Bonneville Power Administration
Carty	Carty natural gas-fired generating plant
Colstrip	Colstrip Units 3 and 4 coal-fired generating plant
Coyote Springs	Coyote Springs Unit 1 natural gas-fired generating plant
CPP	U.S. Environmental Protection Agency’s Clean Power Plan
CWIP	Construction work-in-progress
Dth	Decatherm = 10 therms = 1,000 cubic feet of natural gas
EIM	Energy Imbalance Market
EPA	United States Environmental Protection Agency
ESS	Electricity Service Supplier
FERC	Federal Energy Regulatory Commission
FMB	First Mortgage Bond
FPA	Federal Power Act
GRC	General Rate Case for a specified test year
IRP	Integrated Resource Plan
ISFSI	Independent Spent Fuel Storage Installation
kV	Kilovolt = one thousand volts of electricity
Moody’s	Moody’s Investors Service
MW	Megawatts
MWa	Average megawatts
MWh	Megawatt hours
NRC	Nuclear Regulatory Commission
NVPC	Net Variable Power Costs
OATT	Open Access Transmission Tariff
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
PW1	Port Westward Unit 1 natural gas-fired generating plant
PW2	Port Westward Unit 2 natural gas-fired flexible capacity generating plant
RAC	Renewable Adjustment Clause
RPS	Renewable Portfolio Standard
S&P	S&P Global Ratings
SEC	United States Securities and Exchange Commission
Trojan	Trojan nuclear power plant
Tucannon River	Tucannon River Wind Farm
USDOE	United States Department of Energy

PART I

ITEM 1. BUSINESS.

General

Portland General Electric Company (PGE or the Company), a vertically-integrated electric utility with corporate headquarters located in Portland, Oregon, is engaged in the generation, wholesale purchase, transmission, distribution, and retail sale of electricity in the state of Oregon. The Company operates as a cost-based, regulated electric utility with revenue requirements and customer prices determined based on the forecasted cost to serve retail customers and a reasonable rate of return as determined by the Public Utility Commission of Oregon (OPUC). PGE meets its retail load requirement with both Company-owned generation and power purchased in the wholesale market. The Company participates in the wholesale market through the purchase and sale of electricity and natural gas in an effort to obtain reasonably-priced power to serve its retail customers. PGE, incorporated in 1930, is publicly-owned, with its common stock listed on the New York Stock Exchange. The Company operates as a single business segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis.

PGE's state-approved service area allocation of 4,000 square miles is located entirely within Oregon and includes 51 incorporated cities. During 2019, the Company added 10,000 customers, and as of December 31, 2019, served a total of 895,000 retail customers.

Employees

PGE had 2,949 employees as of December 31, 2019, with 775 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 719 and 56 employees and expire March 2022 and August 2022, respectively.

Available Information

PGE's periodic and current reports, and amendments to those reports, are available and may be accessed free of charge through the Investors section of the Company's website at PortlandGeneral.com as soon as reasonably practicable after the reports are electronically filed with, or furnished to, the United States Securities and Exchange Commission (SEC). It is not intended that PGE's website and the information contained therein or connected thereto be incorporated into this Annual Report on Form 10-K.

Regulation

Federal and state of Oregon (State) regulation each have a significant impact on the operations of PGE. In addition to the agencies and activities discussed below, the Company is subject to regulation by certain environmental agencies, as described in the Environmental Matters section in this Item 1.

Federal Regulation

Several federal agencies, including the Federal Energy Regulatory Commission (FERC), the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), and the Nuclear Regulatory Commission (NRC), have regulatory authority over certain of PGE's operations and activities, as described in the discussion that follows.

PGE is a "licensee," a "public utility," and a "user, owner, and operator of the bulk power system," as defined in the Federal Power Act (FPA). As such, the Company is subject to regulation by the FERC in matters related to wholesale energy activities, transmission services, reliability and cyber security standards, natural gas pipelines, hydroelectric projects, accounting policies and practices, short-term debt issuances, and certain other matters.

Wholesale Energy—PGE has authority under its FERC Market-Based Rates tariff to charge market-based rates for wholesale energy sales in all markets in which it sells electricity except in its own Balancing Authority Area (BAA). The BAA is the area in which PGE is responsible for balancing customer demand with electricity supply, in real time, and the tariff exception within PGE's BAA does not have a material impact on the Company.

Transmission—PGE offers wholesale electricity transmission service pursuant to its Open Access Transmission Tariff (OATT), which contains rates and terms and conditions of service, as filed with, and approved by, the FERC.

Reliability and Cyber Security Standards—The FERC has adopted mandatory reliability standards for owners, users, and operators of the bulk power system. Such standards, which are applicable to PGE, were developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC), which have responsibility for compliance and enforcement of these standards, and are intended to help protect critical cyber assets used to support reliable operations.

Natural Gas Pipelines—The FERC has authority in matters related to the construction, operation, extension, enlargement, safety, and abandonment of jurisdictional interstate natural gas pipeline facilities, as well as transportation rates and accounting for interstate natural gas commerce. PGE is subject to such authority as the Company has a 79.5% ownership interest in the Kelso-Beaver (KB) Pipeline, a 17-mile interstate pipeline that provides natural gas to Port Westward Unit 1 (PW1), Port Westward Unit 2 (PW2), and Beaver, the Company's natural gas-fired generating plants located near Clatskanie, Oregon. As the operator of record of the KB Pipeline, PGE is subject to the requirements and regulations enacted under the Pipeline Safety Laws administered by the PHMSA, which include safety standards, operator qualification standards, and public awareness requirements.

Hydroelectric Licensing—As required under the FPA, PGE holds FERC licenses for all Company-owned hydroelectric generating plants. The FERC license process includes an extensive public review process that involves the consideration of numerous natural resource issues and environmental conditions. For additional information, see the Environmental Matters section in this Item 1. and the Generating Facilities section in Item 2. —"Properties."

Accounting Policies and Practices—PGE prepares periodic and current reports in accordance with accounting principles generally accepted in the United States of America (GAAP). In addition, the Company prepares, pursuant to applicable provisions of the FPA, financial statements in accordance with the accounting requirements of the FERC, as set forth in its applicable Uniform System of Accounts and published accounting releases. Such financial statements are included in annual and quarterly reports filed with the FERC.

Short-term Debt—Pursuant to applicable provisions of the FPA and FERC regulations, regulated public utilities are required to obtain FERC approval to issue certain securities.

Spent Fuel Storage—The NRC regulates the licensing and decommissioning of nuclear power plants, including PGE's decommissioned Trojan nuclear power plant (Trojan), which was closed in 1993. For additional information on spent nuclear fuel storage activities, see Note 8, Asset Retirement Obligations in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data" and *"Hazardous Material"* in the Environmental Matters section of this Item 1.

State of Oregon Regulation

PGE is subject to the jurisdiction of the OPUC, which reviews and approves the Company's retail prices and reviews the Company's generation and transmission resource acquisition plans, pursuant to a biennial integrated resource planning process. The OPUC regulates the issuance of securities, prescribes accounting policies and practices, regulates the sale of utility assets, reviews transactions with affiliated companies, and has jurisdiction over the acquisition of, or exertion of substantial influence over, public utilities.

Customer prices are determined through formal proceedings that generally include testimony by participating parties, discovery, public hearings, and the issuance of a final order. Participants in such proceedings may include PGE, OPUC staff, and intervenors representing PGE customer groups, as well as other interested parties. The following are the more significant regulatory mechanisms and proceedings under which customer prices are determined:

- *General Rate Cases*. PGE periodically evaluates the need to change its retail electric price structure as part of a comprehensive general rate case process that reflects revenue requirements based on a forecasted test year. The OPUC authorizes the Company's debt-to-equity capital structure, return on equity, overall rate of return, and customer prices. For additional information regarding the Company's most recent general rate cases, see "*General Rate Case*" in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."
- *Annual Power Cost Updates*. The OPUC has approved an Annual Power Cost Update Tariff (AUT) by which PGE can adjust retail customer prices annually to reflect forecasted changes in the Company's net variable power costs (NVPC). NVPC consists of the cost of power purchased and fuel used to generate electricity, as well as the cost of settled electric and natural gas financial contracts (all classified as Purchased power and fuel expense in the Company's consolidated statements of income) and is net of wholesale revenues, which are classified as Revenues, net in the consolidated statements of income. The OPUC has also authorized a Power Cost Adjustment Mechanism (PCAM), under which PGE may share with customers a portion of actual cost variances associated with NVPC.
- *Renewable Energy.* The State maintains a Renewable Portfolio Standard (RPS) which requires PGE to serve a portion of its retail load with renewable resources. In conjunction with the RPS, the State established a renewable adjustment clause (RAC) mechanism that allows for the recovery in customer prices of prudently incurred costs to comply with the RPS. The State also passed a law referred to as the Oregon Clean Electricity and Coal Transition Plan (SB 1547), which, among its provisions, increased the RPS percentages in certain future years. For further information on SB 1547, see *Carbon Legislation* in the *"Overview"* section of Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations.

Retail Customer Choice Program—Under cost of service pricing, residential and small commercial customers may select portfolio options from PGE that include time-of-use and renewable resource pricing.

All commercial and industrial customers are eligible for pricing options other than cost of service for a one-year period, including daily market index-based pricing, under which the Company provides the electricity, and Direct Access, whereby customers purchase electricity directly from an Electricity Service Supplier (ESS). PGE receives revenue from Direct Access customers only for the transmission and delivery of the volume of electricity provided along with fixed transition adjustments intended to prevent the shifting of excess charges to the Company's cost of service customers. Certain large commercial and industrial customers may elect a fixed three-year or a minimum five-year term, to be served either by an ESS, or by the Company under the daily market index-based price option. Participation in the fixed three-year and minimum five-year opt-out programs for existing and planned load is capped at 300 average megawatts (MWa) in aggregate.

In 2018, the OPUC created and approved rules for a New Large Load Direct Access program, capped at 119 MWa, for unplanned, large, new loads and large load growth at existing sites. In January 2020, the OPUC issued an order that will require PGE to begin serving customers under this program in early February 2020.

For further information regarding Direct Access deliveries, see *"Customers and Demand"* in the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Regulatory Accounting

PGE prepares financial statements in accordance with GAAP and, as a regulated public utility, the effects of rate regulation are reflected in its financial statements. GAAP provides for the deferral, as regulatory assets, of certain actual or estimated costs that would otherwise be charged to expense, based on expected recovery from customers in future prices. Likewise, certain actual or anticipated credits that would otherwise be recognized as revenue or reduce expense can be deferred as regulatory liabilities, based on expected future credits or refunds to customers. PGE records regulatory assets or liabilities if it is probable that they will be reflected in future prices, based on regulatory orders or other available evidence.

The Company periodically assesses the applicability of regulatory accounting to its business, considering both the current and anticipated future regulatory environment and related accounting guidance. For additional information, see *"Regulatory Assets and Liabilities"* in Note 2, Summary of Significant Accounting Policies, and Note 7, Regulatory Assets and Liabilities, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Customers and Revenues

PGE generates revenue primarily through the sale and delivery of electricity to retail customers located exclusively in Oregon. In addition, the Company distributes power to commercial and industrial customers that choose to purchase their energy from an ESS. Although the Company includes such Direct Access customers in its customer counts and energy delivered to such customers in its total retail energy deliveries, retail revenues include only delivery charges and applicable transition adjustments for these Direct Access customers. The Company conducts retail electric operations within its service territory and competes with: i) the local natural gas distribution company for the energy needs of residential and commercial space heating, water heating, and appliances; and ii) ESSs. Energy efficiency, conservation measures and distributed solar generation also have an increasing influence on customer demand.

Retail Revenues

Retail customers are classified as residential, commercial, or industrial, with no single customer representing more than 7% of PGE's total retail revenues or 11% of total retail deliveries.

PGE's Retail revenues, retail energy deliveries, and average number of retail customers consist of the following:

	Years Ended December 31,					
	2019		2018		2017	
Retail revenues[1] (dollars in millions):						
Residential	$ 981	52%	$ 948	53%	$ 969	52%
Commercial	654	35	665	37	669	36
Industrial	222	12	210	12	212	11
Subtotal	1,857	99	1,823	102	1,850	99
Alternative revenue programs, net of amortization	2	—	3	—	—	—
Other accrued (deferred) revenues, net[2]	22	1	(45)	(2)	10	1
Total retail revenues	$ 1,881	100%	$ 1,781	100%	$ 1,860	100%
Retail energy deliveries[3] (MWh in thousands):						
Residential	7,471	38%	7,416	39%	7,880	40%
Commercial	7,318	38	7,430	39	7,555	38
Industrial	4,671	24	4,376	22	4,283	22
Total retail energy deliveries	19,460	100%	19,222	100%	19,718	100%
Average number of retail customers:						
Residential	779,673	88%	772,389	88%	762,211	88%
Commercial	110,084	12	109,107	12	107,855	12
Industrial	262	—	270	—	267	—
Total	890,019	100%	881,766	100%	870,333	100%

(1) Includes both revenues from customers who purchase their energy supplies from the Company and revenues from the delivery of energy to those commercial and industrial customers that purchase their energy from ESSs.

(2) Amounts for the years ended December 31, 2019 and 2018 are primarily comprised of $23 million of amortization and $45 million of deferral, respectively, related to the 2018 net tax benefits due to the change in corporate tax rate under the United States Tax Cuts and Jobs Act of 2017 (TCJA).

(3) Includes both energy sold to retail customers and energy deliveries to those commercial and industrial customers that purchase their energy from ESSs.

The following table presents additional averages for retail customers. Certain supplemental tariff collections are excluded from revenues as they are not considered a part of the Company's base retail prices for these calculations.

	Years Ended December 31,		
	2019	2018	2017
Residential			
Revenue per customer (in dollars):	$ 1,177	$ 1,153	$ 1,181
Usage per customer (in kilowatt hours):	9,582	9,601	10,338
Revenue per kilowatt hour (in cents):	12.28¢	12.01¢	11.42¢
Commercial			
Revenue per customer (in dollars):	$ 5,901	$ 6,051	$ 6,142
Usage per customer (in kilowatt hours):	66,481	68,096	70,046
Revenue per kilowatt hour (in cents):	8.88¢	8.89¢	8.77¢
Industrial			
Revenue per customer (in dollars):	$ 847,079	$ 776,245	$ 792,466
Usage per customer (in kilowatt hours):	17,827,115	16,207,263	16,041,461
Revenue per kilowatt hour (in cents):	4.75¢	4.79¢	4.94¢

For additional information, see the Results of Operations section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

In addition to standard cost of service pricing, the Company offers different pricing options including a daily market price option, various time-of-use options, and several renewable energy options, which are offered to residential and small commercial customers. For additional information on customer options, see "*Retail Customer Choice Program*" within the Regulation section of this Item 1.

Residential customers include single family housing, multiple family housing (such as apartments, duplexes, and town homes), mobile homes, and small farms. Residential demand is sensitive to the effects of weather, with demand historically highest during the winter heating season. Increased use of air conditioning in PGE's service territory has caused the summer peaks to increase in recent years, while the historical winter peak has not increased in over 20 years. In the past few years, summer peaks have exceeded winter peaks and long-term load forecasts expect that trend to continue. Economic conditions can also affect residential demand as strong job growth and population growth in PGE's service territory have led to increased customer growth rates. Residential demand is also impacted by energy efficiency measures; however, the Company's decoupling mechanism is intended to mitigate the financial effects of such measures.

Commercial customers consist of non-residential customers who accept energy deliveries at voltages equivalent to those delivered to residential customers. This customer class includes most businesses, small industrial companies, and public street and highway lighting accounts. The Company's commercial customer demand is somewhat less susceptible to weather conditions than residential customer demand. Economic conditions and fluctuations in total employment in the region can also lead to changes in energy demand from commercial customers. Energy efficiency measures also impact commercial demand, although the Company's decoupling mechanism partially mitigates the financial effects of such measures.

Industrial customers consist of non-residential customers who accept delivery at higher voltages than commercial customers, with pricing based on the amount of electricity delivered under the applicable tariff. Demand from industrial customers is primarily driven by economic conditions, with weather having little impact on this customer class.

Wholesale Revenues

PGE participates in the wholesale electricity marketplace in order to balance its supply of power to meet the needs of its retail customers. Interconnected transmission systems in the western United States serve utilities with diverse load requirements and allow the Company to purchase and sell electricity, largely through bi-lateral agreements, within the region to serve retail demand, depending upon the relative price and availability of power, hydro and wind conditions, and daily and seasonal retail demand. PGE also participates in the California Independent System Operator's western Energy Imbalance Market (western EIM), which allows for load balancing with other western EIM participants in five-minute intervals. Wholesale revenues represented 8% of total revenues in 2019 and 2018, and 5% in 2017.

Other Operating Revenues

Other operating revenues consist primarily of gains and losses on the sale of natural gas volumes purchased that exceeded what was needed to fuel the Company's generating facilities, as well as revenues from transmission services, excess transmission capacity resales, pole attachment rentals, and other electric services provided to customers. Other operating revenues represented 3% of total revenues in 2019 and 2018, and 2% in 2017.

Seasonality

Demand for electricity by PGE's residential and, to a lesser extent, commercial customers, is affected by seasonal weather conditions. The Company uses heating and cooling degree-days to determine the effect of weather on the demand for electricity. Heating and cooling degree-days, determined by taking the difference between the average daily temperature and a baseline of 65 degrees, provide cumulative variances over a period of time, to indicate the extent to which customers are likely to have used electricity for heating or cooling. The higher the number of degree-days, the greater the expected demand for electricity.

The following table presents the heating and cooling degree-days for the most recent three-year period, along with 15-year averages for the most recent year provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-Days	Cooling Degree-Days
2019	4,165	564
2018	3,702	692
2017	4,558	700
15-year average	4,140	531

PGE’s all-time high net system load peak of 4,073 megawatts (MW) occurred in December 1998. The Company’s all-time summer peak of 3,976 MW occurred in August 2017. The following table presents PGE’s average winter (defined as January, February, and December) and summer (defined as June through September) loads for the periods presented, along with the corresponding peak load (in MWs) and month in which such peak occurred. As the table below illustrates, although the average winter loads continue to run higher than average summer loads, the Company continues to experience its highest annual peak loads during the summer months:

	Winter Loads			Summer Loads		
	Average	Peak	Month	Average	Peak	Month
2019	2,609	3,422	February	2,263	3,765	June
2018	2,519	3,399	February	2,301	3,816	August
2017	2,698	3,727	January	2,335	3,976	August

The Company tracks and evaluates both load growth and peak load requirements for purposes of long-term load forecasting, integrated resource planning, and preparing general rate case assumptions. Behavior patterns, conservation, energy efficiency initiatives and measures, weather effects, economic conditions, and demographic changes all play a role in determining expected future customer demand and the resulting resources the Company will need to adequately meet those loads and maintain adequate capacity reserves.

Power Supply

PGE utilizes its generating resources, as well as wholesale power purchases from third parties to meet the needs of its retail customers. The volume of electricity the Company generates is dependent upon, among other factors, the capacity and availability of its generating resources and the price and availability of wholesale power and natural gas. As part of its power supply operations, the Company enters into short- and long-term power and fuel purchase agreements. PGE executes economic dispatch decisions concerning its own generation and participates in the wholesale market in an effort to obtain reasonably-priced power for its retail customers, manage risk, and administer its long-term wholesale contracts. The Company also promotes energy efficiency measures to meet its energy requirements.

PGE's resource and contracted capacity (in MW) was as follows:

	As of December 31,			
	2019		2018	
	Capacity	%	Capacity	%
Generation:				
Thermal [(1)]:				
Natural gas	1,830	35%	1,830	36%
Coal	814	15	814	16
Total thermal	2,644	50	2,644	53
Wind [(2)]	717	14	717	14
Hydro [(3)]	495	9	495	10
Total generation	3,856	73	3,856	77
Purchased power:				
Long-term contracts:				
Hydro [(3)]	462	9	522	10
PURPA qualifying facilities [(4)]	133	3	61	1
Dispatchable standby generation	125	2	129	3
Capacity	100	2	100	2
Wind [(2)]	100	2	100	2
Solar	7	—	13	—
Biomass	10	—	10	—
Total long-term contracts	937	18	935	18
Short-term contracts	471	9	273	5
Total purchased power	1,408	27	1,208	23
Total resource capacity	5,264	100%	5,064	100%

(1) Capacity represents the MW the plants are capable of generating under normal operating conditions, which is affected by ambient temperatures, net of electricity used in the operation of the plant.
(2) Capacity represents nameplate and differs from expected energy to be generated, which is expected to have a capacity factor range from 30 to 40%, dependent upon wind conditions.
(3) Capacity represents net capacity and differs from expected energy to be generated, which is expected to have a capacity factor range from 40 to 50%, dependent upon river flows.
(4) Capacity represents contracted capacity under the Public Utility Regulatory Policies Act of 1978 (PURPA).

For information regarding actual generating output and purchases for the years ended December 31, 2019 and 2018, see the Results of Operations section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Generation

PGE's generating resources consist of seven thermal plants (natural gas- and coal-fired), two wind farms, and seven hydroelectric facilities. The portion of PGE's retail load requirements generated by its plants varies from year to year and is determined by various factors, including planned and unplanned outages, availability and price of coal and natural gas, precipitation and snow-pack levels, the market price of electricity, and wind variability. For a complete listing of these facilities, see "*Generating Facilities*" in Item 2.—"Properties."

Thermal The Company has five natural gas-fired generating facilities: PW1, PW2, Beaver, Coyote Springs Unit 1 (Coyote Springs), and Carty Generating Station (Carty).

The Company operates, and has a 90% ownership interest in, Boardman and has a 20% ownership interest in the Colstrip Units 3 and 4 coal-fired generating plant (Colstrip), which is operated by a third party. Boardman is scheduled to cease coal-fired operations at the end of 2020 and, pursuant to SB 1547, PGE's portion of Colstrip is scheduled to be fully depreciated by 2030, with the potential to utilize the output of the facility, in Oregon, until 2035. For additional information on SB 1547, see *"Carbon Legislation"* in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Wind PGE owns and operates two wind farms, Biglow Canyon Wind Farm (Biglow Canyon) and Tucannon River Wind Farm (Tucannon River). Biglow Canyon, located in Sherman County, Oregon, is PGE's largest renewable energy resource consisting of 217 wind turbines with a total nameplate capacity of 450 MW. Tucannon River, located in southeastern Washington, consists of 116 wind turbines with a total nameplate capacity of 267 MW. PGE plans to add 300 MW of additional wind resource capacity from the construction of the Wheatridge Renewable Energy Facility (Wheatridge), of which PGE will own 100 MW. The wind component of the facility is expected to be operational in December 2020. For additional information on Wheatridge, see *"The Resource Planning Process"* in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Hydro The Company's FERC-licensed hydroelectric projects consist of Pelton/Round Butte on the Deschutes River near Madras, Oregon (discussed below), four plants on the Clackamas River, and one on the Willamette River.

PGE has a 66.67% ownership interest in the 455 MW Pelton/Round Butte hydroelectric project on the Deschutes River, with the remaining interest held by the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS). A 50-year joint license for the project, which is operated by PGE, was issued by the FERC in 2005. The CTWS has an option to purchase an additional undivided 16.66% interest in Pelton/Round Butte at their discretion on December 31, 2021. CTWS has a second option in 2036 to purchase an undivided 0.02% interest in Pelton/Round Butte. If both options are exercised, CTWS's ownership percentage would exceed 50%.

Fuel Supply—PGE contracts for natural gas and coal supplies required to fuel the Company's thermal generating plants, with certain plants also able to operate on fuel oil if needed. In addition, the Company uses forward, future, swap, and option contracts to manage its exposure to volatility in natural gas prices.

Natural Gas Physical supplies of natural gas are generally purchased up to 12 months in advance of delivery and based on anticipated operation of the plants. PGE manages the price risk of natural gas supply through the use of financial contracts up to 60 months in advance of expected need of energy.

PGE owns 79.5%, and is the operator of record, of the KB Pipeline, which directly connects PW1, PW2, and Beaver to the Northwest Pipeline, an interstate natural gas pipeline operating between British Columbia and New Mexico. Currently, PGE transports natural gas on the KB Pipeline for its own use under a firm transportation service agreement, with capacity offered to others on an interruptible basis to the extent not utilized by the Company. PGE has access to 114,000 Dth per day of firm natural gas transportation capacity to serve the three plants.

PGE has access to 4.1 billion cubic feet of natural gas storage in Mist, Oregon from which it can draw when economic factors favor its use or in the event that natural gas supplies are interrupted. The storage facility is owned and operated by a local natural gas company, NW Natural, and may be utilized to provide fuel to PW1, PW2, and Beaver.

To serve Coyote Springs and Carty, PGE has access to 120,000 Dth per day of firm natural gas transportation capacity on three pipeline systems accessing gas fields in Alberta, Canada.

Coal PGE has purchase agreements that, together with existing inventory, will provide coal sufficient for the anticipated operating needs for Boardman during 2020 until it ceases coal-fired operations. The

Colstrip co-owners obtain coal to fuel the plant via conveyor belt from a mine that lies adjacent to the facility and is the sole source of coal supply for the plant. PGE's coal supply contract with the owner of the mine is scheduled to expire at the end of 2025. The terms of contracts and the quality of coal are expected to be in alignment with required emissions limits.

Purchased Power

PGE supplements its own generation with power purchased in the wholesale market to meet its retail load requirements. The Company utilizes short- and long-term wholesale power purchase contracts in an effort to provide the most favorable economic mix on a variable cost basis.

PGE's medium-term power cost strategy helps mitigate the effect of price volatility on its customers due to changing energy market conditions. The strategy allows the Company to take positions in power and fuel markets up to five years in advance of physical delivery. By purchasing a portion of anticipated energy needs for future years over an extended period, PGE mitigates a portion of the potential future volatility in the average cost of purchased power and fuel.

The Company's major power purchase contracts consist of the following (also see the preceding table which summarizes the average resource capabilities related to these contracts):

Hydro—During 2019, the Company had the following agreements:

- *Mid-Columbia hydro*—PGE has long-term power purchase contracts with certain public utility districts in the state of Washington for a portion of the output of two hydroelectric projects on the mid-Columbia River; one contract representing 98 MW of capacity that expires in 2028 and one contract representing 165 MW of capacity that expires in 2052. Although the projects currently provide a total of 263 MW of capacity, actual energy received is dependent upon river flows and capacity amounts may decline over time.
- *CTWS*—PGE has a long-term agreement under which the Company purchases, at index prices, CTWS' interest in the output of the Pelton/Round Butte hydroelectric project. Although the agreement provides approximately 162 MW of net capacity, actual energy received is dependent upon river flows. The term of the agreement coincides with the term of the FERC license for this project, which expires in 2055. In 2014, PGE entered into an agreement with CTWS under which CTWS has agreed to sell, on modified payment terms, its share of the energy generated from the Pelton/Round Butte hydroelectric project exclusively to the Company through 2024.
- *Other*— PGE has one contract that provides for the purchase of power generated from a hydroelectric project with capacity of 37 MW and contract expiration in 2032.

PURPA qualifying facilities—PGE is required to purchase power from PURPA qualifying facilities (QFs), as mandated by federal law. QFs are generating facilities that fall within the following two categories: 1) qualifying generation facilities with a capacity of 80 MW or less and whose primary energy source is renewable (hydro, wind, solar, biomass, waste, or geothermal); or 2) qualifying cogeneration facilities that sequentially produce electricity and another form of useful thermal energy (e.g., heat, steam) in a way that is more efficient than the separate production of each form of energy. As of December 31, 2019, PGE had contracts with 31 on-line PURPA qualifying facilities, providing a total of 133 MW of capacity. As of December 31, 2019, PGE has 92 contracts with PURPA QFs representing 408 MW of capacity that are not yet operational. Fifty-seven of the QF power purchase agreements (PPAs) are in default because the QF has failed to complete construction and become operational by the date required by the PPA. The PPAs provide that the QF has one year to cure its default. PGE is permitted to immediately terminate the QF PPA upon expiration of the cure period. The term of a QF PPA generally ranges from 15 to 23 years, measured from the date of execution.

The expense and volume of purchases from these facilities for the years-ended December 31, 2019 and 2018 were as follows:

	2019	2018
PURPA contract expense (in millions)	$ 6	$ 5
MWh purchased under PURPA contracts (in thousands)	152	123
Average cost per MWh from PURPA contracts	$ 38.69	$ 43.22

Expenses incurred related to PURPA contracts are included in PGE's AUT.

Dispatchable Standby Generation (DSG)—PGE has a DSG program under which the Company can start, operate, and monitor customer-owned diesel-fueled standby generators when needed to provide NERC-required operating reserves. As of December 31, 2019, there were 59 sites with a total DSG capacity of 125 MW. Additional DSG projects are being pursued with a total goal of 145 MW online by the end of 2020.

Capacity—PGE's capacity contracts are primarily comprised of the following agreements to help meet peak loads:

- Seasonal peaking capacity up to 100MW during the summer and winter peak periods obtained from a natural gas-fired resource, which expires in 2024; and
- Starting in January 2021, an additional 200MW of annual capacity will be added, with a five-year term, primarily obtained from hydroelectric resources.

Wind—PGE has two contracts representing 100 MW of capacity to purchase power generated from renewable wind resources that extend to 2028 and 2035. The expected energy from these wind resources will vary from the nameplate capacity due to varying wind conditions.

Solar—PGE has three contracts representing 7 MW of capacity to purchase power generated from photovoltaic solar projects that extend to 2036 and 2037. The expected energy from these solar resources will vary from the nameplate capacity due to varying solar conditions.

Biomass—PGE has one contract to purchase biomass energy through 2020.

Short-term contracts—These contracts are for delivery periods of one month up to one year in length. They are entered into with various counterparties to provide additional firm energy to help meet the Company's load requirements.

PGE also utilizes spot purchases of power in the open market to secure the energy required to serve its retail customers. Such purchases are made under contracts that range in duration from 15 minutes to less than one month. As of 2017, PGE is also a market participant in the western EIM, which allows certain of its generating plants to receive automated dispatch signals from the CAISO for load balancing with other western EIM participants in five-minute intervals.

For additional information regarding PGE's power purchase contracts, see Note 16, Commitments and Guarantees, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Future Energy Resource Strategy

PGE's IRP outlines the Company's plan to meet future customer demand and describes PGE's future energy supply strategy. For a detailed discussion of the IRPs, see *"The Resource Planning Process"* within the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Transmission and Distribution

Transmission systems deliver energy from generating facilities to distribution systems for final delivery to customers. PGE schedules energy deliveries over its transmission system in accordance with FERC requirements and operates one balancing authority area (an electric system bounded by interchange metering) in its service territory. In 2019, PGE delivered approximately 24 million MWh in its balancing authority area through 1,264 circuit miles of transmission lines operating at or above 115 kilovolts (kV).

PGE's transmission system is part of the Western Interconnection, the regional grid in the western United States. The Western Interconnection includes the interconnected transmission systems of 11 western states, two Canadian provinces and parts of Mexico, and is subject to the reliability rules of the WECC and the NERC. PGE relies on transmission contracts with Bonneville Power Administration (BPA) to transmit a significant amount of the Company's generation to serve its distribution system. PGE's transmission system, together with contractual rights on other transmission systems, enables the Company to integrate and access generation resources to meet its customers' energy requirements. PGE's generation is managed on a coordinated basis to obtain maximum load-carrying capability and efficiency.

The Company's wholesale transmission activities are regulated by the FERC and are offered on a non-discriminatory basis, with all potential customers provided equal access to PGE's transmission system through PGE's OATT. In accordance with its OATT, PGE offers several transmission services to wholesale customers:

- Network integration transmission service, a service that integrates generating resources to serve retail loads;
- Short- and long-term firm point-to-point transmission service, a service with fixed delivery and receipt points; and
- Non-firm point-to-point service, an "as available" service with fixed delivery and receipt points.

For additional information regarding the Company's transmission and distribution facilities, see "*Transmission and Distribution*" in Item 2.—"Properties."

Environmental Matters

PGE's operations are subject to a wide range of environmental protection laws and regulations, which pertain to air and water quality, endangered species and wildlife protection, and hazardous material. Various state and federal agencies regulate environmental matters that relate to the siting, construction, and operation of generation, transmission, and substation facilities and the handling, accumulation, clean-up, and disposal of toxic and hazardous substances. In addition, certain of the Company's hydroelectric projects and transmission facilities are located on property under the jurisdiction of federal and state agencies, and/or tribal entities that have authority in environmental protection matters. The following discussion provides further information on certain regulations that affect the Company's operations and facilities.

Air Quality

Clean Air Act—PGE's operations, primarily its thermal generating plants, are subject to regulation under the federal Clean Air Act (CAA), which addresses particulate matter, hazardous air pollutants, and greenhouse gas emissions (GHGs), among other things. Oregon and Montana, the states in which PGE's thermal facilities are located, also implement and administer certain portions of the CAA and have set standards that are at least as stringent as federal standards. PGE manages its air emissions at its thermal generating plants by the use of low sulfur fuel, emissions and combustion controls and monitoring, and sulfur dioxide allowances awarded under the CAA.

Climate Change—In 2015, the United States Environmental Protection Agency (EPA) released the Clean Power Plan (CPP), under which each state would have to reduce carbon dioxide emissions from its power sector on a state-wide basis. In 2016, the United States Supreme Court halted implementation and enforcement of the CPP.

In August 2018, the EPA proposed the Affordable Clean Energy (ACE) rule, to replace the CPP. On July 8, 2019, the EPA finalized the ACE rule, which establishes guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired plants. With the finalization of the ACE rule, the Clean Power Plan (CPP) is also officially repealed.

As the ACE rule will only apply to coal-fired plants in operation once the state plan is submitted (anticipated to be July 2022), the ACE rule is not expected to impact Boardman, but will be applicable to Colstrip. There is significant ongoing litigation regarding the ACE rule; however, all litigation regarding the CPP has been dismissed. The Company will continue to monitor the development of the state plan in Montana and track ACE rule litigation.

Any laws that would impose emissions taxes or mandatory reductions in GHGs may have a material impact on PGE's operations, as the Company utilizes fossil fuels in its own power generation and other companies use such fuels to generate power that PGE purchases in the wholesale market. If incremental costs were incurred as a result of changes in the regulations regarding GHGs, the Company would seek recovery in customer prices.

PGE's carbon-emitting facilities provided 69% of the Company's net generating capacity at December 31, 2019.

For more information regarding GHGs and related environmental regulation, see *Carbon Legislation* in the *"Overview"* section of Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations.

Water Quality

The federal Clean Water Act requires that any federal license or permit to conduct an activity that may result in a discharge to waters of the United States must first receive a water quality certification from the state in which the activity will occur. In Oregon, Montana, and Washington, the Departments of Environmental Quality are responsible for reviewing proposed projects under this requirement to ensure that federally approved activities will meet water quality standards and policies established by the respective state. PGE has obtained permits where required and has certificates of compliance for its hydroelectric operations under the FERC licenses. The Company is currently subject to litigation with regard to water quality conditions on the Deschutes River. For additional information on this litigation see "*Deschutes River Alliance Clean Water Act Claims"* in Note 19, Contingencies in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Threatened and Endangered Species and Wildlife

Fish Protection—The federal Endangered Species Act (ESA) has granted protection to many populations of migratory fish species in the Pacific Northwest. Long-term recovery plans for these species continue to have operational impacts on many of the region's hydroelectric projects. PGE continues to implement fish protection measures at its hydroelectric projects that were prescribed by the U.S. Fish and Wildlife Service and the National Marine Fisheries Service under their authority granted in the ESA and the FPA. Conditions required with the operating licenses are expected to result in a minor reduction in power production and continued capital spending to modify the facilities to enhance fish passage and survival.

Avian Protection—Various statutes, including the Migratory Bird Treaty Act and Bald and Golden Eagle Protection Act, contain provisions for civil, criminal, and administrative penalties resulting from the unauthorized take of migratory birds and eagles. Because PGE operates facilities that can pose risks to a variety of such birds, the Company developed an avian protection plan to help address and reduce risks to bird species that may be affected by Company operations. PGE has implemented such a plan for its transmission, distribution, and thermal generation facilities and continues to finalize similar plans, for its wind generation facilities.

Hazardous Material

PGE has a comprehensive program to comply with requirements of both federal and state regulations related to the storage, handling, and disposal of hazardous materials. The handling and disposal of hazardous materials from Company facilities is subject to regulation under the federal Resource Conservation and Recovery Act (RCRA). In addition, the use, disposal, and clean-up of polychlorinated biphenyls, contained in certain electrical equipment, are regulated under the federal Toxic Substances Control Act.

PGE is also subject to regulation under the Comprehensive Environmental Response Compensation and Liability Act, commonly referred to as Superfund, which provides authority to the EPA to assert joint and several liability for investigation and remediation costs for designated Superfund sites.

An investigation by the EPA that began in 1997 of a segment of the Willamette River in Oregon known as Portland Harbor, revealed significant contamination of river sediments and prompted the EPA to designate Portland Harbor as a Superfund site. The EPA listed PGE among the more than one hundred Potentially Responsible Parties in this matter, as PGE historically owned or operated property near the river. For additional information regarding the EPA action on Portland Harbor, see Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

PGE is subject to regulation by the USDOE, which, under the Nuclear Waste Policy Act of 1982, is responsible for the permanent storage and disposal of spent nuclear fuel. PGE has contracted with the USDOE for permanent disposal of spent nuclear fuel from Trojan that is stored in the Independent Spent Fuel Storage Installation (ISFSI), an NRC-licensed interim dry storage facility that houses the fuel at the former plant site. The NRC approved the transfer of spent nuclear fuel from a spent fuel pool to the ISFSI where it is expected to remain until permanent off-site storage is available. Shipment of the spent nuclear fuel from the ISFSI to off-site storage is not expected to be completed prior to 2059. For additional information regarding this matter, see "*Trojan decommissioning activities*" in Note 8, Asset Retirement Obligations, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Information about Our Executive Officers

The following are PGE's current executive officers:

Name	Age	Current Position and Previous Experience	Year Appointed Officer
Larry N. Bekkedahl	59	Vice President, Grid Architecture, Integration and Systems Operations (January 2019 to present), Vice President Transmission and Distribution (August 2014 to January 2019). Senior Vice President of Transmission Services at Bonneville Power Administration ("BPA") (June 2012 to August 2014), Vice President of Engineering and Technical Services at BPA (2008 to June 2012).	2014
Bradley Y. Jenkins	56	Vice President, Utility Operations (January 2019 to present), Vice President, Generation and Power Operations (October 2017 to January 2019), Vice President, Power Supply Generation (September 2015 to October 2017), General Manager, Diversified Plant Operations, (November 2013 to August 2015), Plant General Manager, Boardman Power Plant (September 2012 to November 2013), Operations Manager, Boardman Power Plant (March 2012 to September 2012).	2015
Lisa A. Kaner	59	Vice President, General Counsel and Corporate Compliance Officer (July 2017 to present), trial attorney and shareholder at Markowitz Herbold PC (1994 to June 2017).	2017

John T. Kochavatr	46	Vice President, Information Technology and Chief Information Officer (February 2018 to present). Senior Vice President and Chief Information Officer at SUEZ Water Technologies & Solutions (formerly General Electric Water and Process Technologies) (October 2017 to January 2018), Chief Information Officer and Chief Digital Officer at General Electric Water and Process Technologies (November 2012 to September 2017).	2018
James F. Lobdell	61	Senior Vice President, Finance, Chief Financial Officer and Treasurer (March 2013 to present), Vice President, Power Operations and Resource Strategy (August 2004 to March 2013), Vice President, Power Operations (September 2002 to August 2, 2004), Vice President, Risk Management Reporting, Controls and Credit (May 2001 until September 2002).	2001
John McFarland	39	Vice President, Customer Solutions and Chief Customer Officer (April 2019 to present). Director, Global Digital Experience at General Motors (February 2016 to March 2019), Chief Marketing Officer at OnStar (a subsidiary of General Motors, October 2012 to January 2016), Senior Manager of Strategy at General Motors (September 2010 to September 2012), Brand Management and Finance at Procter & Gamble (August 2002 to August 2010).	2019
Anne F. Mersereau	57	Vice President, Human Resources, Diversity and Inclusion (January 2016 to present), Employee Services Manager (January 2014 to January 2016), Change Management Consultant (January 2012 to January 2014), Human Resources Business Partner (July 2009 to December 2011).	2016
William O. Nicholson	61	Vice President, Utility Technical Services (January 2019 to December 2019), Senior Vice President, Transmission and Distribution, (July 2018 to January 2019), Senior Vice President, Customer Service, Transmission and Distribution (April 2011 to July 2018), Vice President, Distribution Operations (August 2009 to April 2011), Vice President, Customers and Economic Development (May 2007 to August 2009). General Manager, Distribution Western Region (April 2004 to May 2007), General Manager, Distribution Line Operations and Services (February 2002 to April 2004). Mr. Nicholson retired effective December 31, 2019.	2007
Maria M. Pope	55	President (October 2017 to present) and Chief Executive Officer (January 2018 to present), Senior Vice President, Power Supply, Operations and Resource Strategy (March 2013 to January 2018), Senior Vice President, Finance, Chief Financial Officer and Treasurer (January 2009 to February 2013). Board director (January 2006 to December 2008). Vice President and Chief Financial Officer for Mentor Graphics Corporation (July 2007 to December 2008).	2009
W. David Robertson	53	Vice President, Public Policy (August 2009 to present), Director of Government Affairs (June 2004 to August 2009).	2009
Kristin A. Stathis	56	Vice President, Operations Services (May 2019 to present), Vice President, Customer Solutions (January 2019 to May 2019), Vice President, Customer Service Operations (June 2011 to December 2018), General Manager of Revenue Operations (August 2009 to May 2011), Assistant Treasurer and Manager of Corporate Finance (October 2005 to July 2009), General Manager of Power Supply Risk Management (August 2003 to September 2005).	2011

ITEM 1A. RISK FACTORS.

Certain risks and uncertainties that could have a significant impact on PGE's business, financial condition, results of operations, or cash flows, or that may cause the Company's actual results to vary materially from the forward-looking statements contained in this Annual Report on Form 10-K, include those set forth below.

Recovery of PGE's costs is subject to regulatory review and approval, and the inability to recover costs may adversely affect the Company's results of operations.

The prices that PGE charges for its retail services, as authorized by the OPUC, are a major factor in determining the Company's operating income, financial position, liquidity, and credit ratings. As a general matter, PGE seeks to recover in customer prices most of the costs incurred in connection with the operation of its business, including, among other things, costs related to capital projects (such as the construction of new facilities or the modification of existing facilities), the costs of compliance with legislative and regulatory requirements, and the costs of damage from storms and other natural disasters. However, there can be no assurance that such recovery will be granted. The OPUC has the authority to disallow the recovery of any costs that it considers imprudently incurred. Although the OPUC is required to establish customer prices that are fair, just and reasonable, it has significant discretion in the interpretation of this standard.

PGE attempts to manage its costs at levels consistent with the OPUC approved prices. However, if the Company is unable to do so, or if such cost management results in increased operational risk, the Company's financial and operating results could be adversely affected.

Economic conditions that result in reduced demand for electricity and impair the financial stability of some of PGE's customers could affect the Company's results of operations.

Unfavorable economic conditions in Oregon may result in reduced demand for electricity. Such reductions in demand could adversely affect PGE's results of operations and cash flows. Economic conditions could also result in an increased level of uncollectible customer accounts and cause the Company's vendors and service providers to experience cash flow problems and be unable to perform under existing or future contracts.

Market prices for power and natural gas are subject to forces that are often not predictable and that can result in price volatility and general market disruption, adversely affecting PGE's costs and ability to manage its energy portfolio and procure required energy supply, which ultimately could have an adverse effect on the Company's liquidity and results of operations.

As part of its normal business operations, PGE purchases power and natural gas in the open market under short- and long-term contracts, which may specify variable prices or volumes. Market prices for power and natural gas are influenced primarily by factors related to supply and demand. These factors generally include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric and wind generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth, and changes in technology.

Volatility in these markets can affect the availability, price and demand for power and natural gas. Disruption in power and natural gas markets could result in a deterioration of market liquidity, increase the risk of counterparty default, affect regulatory and legislative processes in unpredictable ways, affect wholesale power prices, and impair PGE's ability to manage its energy portfolio. Changes in power and natural gas prices can also affect the fair value of derivative instruments and cash requirements to purchase power and natural gas. If power and natural gas prices decrease from those contained in the Company's existing purchased power and natural gas agreements, PGE may be required to provide increased collateral, which could adversely affect the Company's liquidity. Conversely, if power and natural gas prices rise, especially during periods when the Company requires greater-than-expected volumes that must be purchased at market or short-term prices, PGE could incur greater costs than originally estimated.

The risk of volatility in power costs is partially mitigated through the AUT and the PCAM. Application of the PCAM requires that PGE absorb certain power cost increases before the Company is allowed to recover any amount from customers. Accordingly, the PCAM is expected to only partially mitigate the potentially adverse financial impacts of forced generating plant outages, reduced hydro and wind availability, interruptions in fuel supplies, and volatile wholesale energy prices.

The effects of weather on electricity usage can adversely affect results of operations.

Weather conditions can adversely affect PGE's revenues and costs, impacting the Company's results of operations. Variations in temperatures can affect customer demand for electricity, with warmer-than-normal winter seasons or cooler-than-normal summer seasons reducing the demand for energy. Weather conditions are the dominant cause of usage variations from normal seasonal patterns, particularly for residential customers. Severe weather can also disrupt energy delivery and damage the Company's transmission and distribution system.

Rapid increases in load requirements resulting from unexpected adverse weather changes, particularly if coupled with transmission constraints, could adversely impact PGE's cost and ability to meet the energy needs of its customers. Conversely, rapid decreases in load requirements could result in the sale of excess energy at depressed market prices.

Forced outages at PGE's generating plants can increase the cost of power required to serve customers because the cost of replacement power purchased in the wholesale market generally exceeds the Company's cost of generation.

Forced outages at the Company's generating plants could result in power costs greater than those included in customer prices. As indicated above, application of the Company's PCAM could help mitigate adverse financial impacts of such outages; however, the cost sharing features of the mechanism do not provide full recovery in customer prices. Inability to recover such costs in future prices could have a negative impact on the Company's results of operations.

The construction of new facilities, or modifications to existing facilities, is subject to risks that could result in the disallowance of certain costs for recovery in customer prices or higher operating costs.

PGE supplements its own generation with wholesale power purchases to meet its retail load requirement. In addition, long-term increases in both the number of customers and demand for energy will require continued expansion and upgrade of PGE's generation, transmission, and distribution systems. Construction of new facilities and modifications to existing facilities could be affected by various factors, including unanticipated delays and cost increases and the failure to obtain, or delay in obtaining, necessary permits from state or federal agencies or tribal entities, which could result in failure to complete the projects and the disallowance of certain costs in the rate determination process. In addition, failure to complete construction projects according to specifications could result in reduced plant efficiency, equipment failure, and plant performance that falls below expected levels, which could increase operating costs.

Adverse changes in PGE's credit ratings could negatively affect its access to the capital markets and its cost of borrowed funds.

Access to capital markets is important to PGE's ability to operate its business and complete its capital projects. Credit rating agencies evaluate the Company's credit ratings on a periodic basis and when certain events occur. A ratings downgrade could increase fees on PGE's revolving credit facilities and letter of credit facilities, increasing the cost of funding day-to-day working capital requirements, and could also result in higher interest rates on future long-term debt. A ratings downgrade could also restrict the Company's access to the commercial paper market, a principal source of short-term financing, or result in higher interest costs.

In addition, if Moody's Investors Service (Moody's) and/or S&P Global Ratings (S&P) reduce their rating on PGE's unsecured debt to below investment grade, the Company could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, which could have an adverse effect on the Company's liquidity.

PGE is subject to various legal and regulatory proceedings, the outcome of which is uncertain, and resolution unfavorable to PGE could adversely affect the Company's results of operations, financial condition, or cash flows.

In the normal course of its business, PGE is subject to various regulatory proceedings, lawsuits, claims, and other matters, which could result in adverse judgments, settlements, fines, penalties, injunctions, or other relief. These matters are subject to many uncertainties, the ultimate outcome of which management cannot predict. The final resolution of certain matters in which PGE is involved could require that the Company incur expenditures over an extended period of time and in a range of amounts that could have an adverse effect on its cash flows and results of operations. Similarly, the terms of resolution could require the Company to change its business practices and procedures, which could also have an adverse effect on its cash flows, financial position, or results of operations.

There are certain pending legal and regulatory proceedings, such as the remediation efforts related to the Portland Harbor site, which may have an adverse effect on results of operations and cash flows for future reporting periods. For additional information, see Item 3.—"Legal Proceedings" and Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Reduced river flows and unfavorable wind conditions can adversely affect generation from hydroelectric and wind generating resources. The Company could be required to replace energy expected from these sources with higher cost power from other facilities or with wholesale market purchases, which could have an adverse effect on results of operations.

PGE derives a significant portion of its power supply from its own hydroelectric facilities and through long-term purchase contracts with certain public utility districts in the state of Washington. Regional rainfall and snowpack levels affect river flows and the resulting amount of energy generated by these facilities. Shortfalls in energy expected from lower cost hydroelectric generating resources would require increased energy from the Company's other generating resources and/or power purchases in the wholesale market, which could have an adverse effect on results of operations.

PGE also derives a portion of its power supply from wind generating resources, for which the output is dependent upon wind conditions. Unfavorable wind conditions could require increased reliance on power from the Company's thermal generating resources or power purchases in the wholesale market, both of which could have an adverse effect on results of operations.

Although the application of the PCAM could help mitigate adverse financial effects from any decrease in power provided by hydroelectric and wind generating resources, full recovery of any increase in power costs is not assured. Inability to fully recover such costs in future prices could have a negative impact on the Company's results of operations, as well as a reduction in renewable energy credits and loss of production tax credits (PTCs) related to wind generating resources.

Capital and credit market conditions could adversely affect the Company's access to capital, cost of capital, and ability to execute its strategic plan as currently envisioned.

Access to capital and credit markets is important to PGE's ability to operate. The Company expects to issue debt and equity securities, as necessary, to fund its future capital requirements. In addition, contractual commitments and regulatory requirements may limit the Company's ability to delay or terminate certain projects.

If the capital and credit market conditions in the United States and other parts of the world deteriorate, the Company's future cost of debt and equity capital, as well as access to capital markets, could be adversely affected. In addition, restrictions on PGE's ability to access capital markets could affect its ability to execute its strategic plan.

Legislative or regulatory efforts to reduce GHG emissions could lead to increased capital and operating costs and have an adverse impact on the Company's results of operations.

Future legislation or regulations could result in limitations on GHGs from the Company's fossil fuel-fired generation facilities. Compliance with any GHG reduction requirements could require PGE to incur significant expenditures, including those related to carbon capture and sequestration technology, purchase of emission allowances and offsets, fuel switching, and the replacement of high-emitting generation facilities with lower-emitting facilities.

The cost to comply with potential GHG reduction requirements is subject to significant uncertainties, including those related to: i) the timing of the implementation of emissions reduction rules; ii) required levels of emissions reductions; iii) requirements with respect to the allocation of emissions allowances; iv) the maturation, regulation, and commercialization of carbon capture and sequestration technology; and v) PGE's compliance alternatives. Although the Company cannot currently estimate the effect of future legislation or regulations on its results of operations, financial condition, or cash flows, the costs of compliance with such legislation or regulations could be material.

Changes in tax laws may have an adverse impact on the Company's financial position, results of operations, and cash flows.

PGE makes judgments and interpretations about the application of tax law when determining the provision for taxes. Such judgments include the timing and probability of recognition of income, deductions, and tax credits, which are subject to challenge by taxing authorities. Additionally, treatment of tax benefits and costs for ratemaking purposes could be different than what the Company anticipates or requests from the state regulatory commission, which could have a negative effect on the Company's financial condition and results of operations.

PGE owns and operates wind generating facilities, which generate PTCs that PGE uses to reduce its federal tax obligations. The amount of PTCs earned depends on the level of electricity output generated and the applicable tax credit rate. A variety of operating and economic parameters, including adverse weather conditions and equipment reliability, could significantly reduce the PTCs generated by the Company's wind facilities resulting in a material adverse impact on PGE's financial condition and results of operations. These PTCs generate tax credit carryforwards that the Company plans to utilize in the future to reduce income tax obligations. If PGE cannot generate enough taxable income in the future to utilize all of the tax credit carryforwards before the credits expire, the Company may incur material charges to earnings.

Under certain circumstances, banks participating in PGE's credit facilities could decline to fund advances requested by the Company or could withdraw from participation in the credit facilities.

PGE currently has a syndicated unsecured revolving credit facility with several banks for an aggregate amount of $500 million. The revolving credit facility provides a primary source of liquidity and may be used to supplement operating cash flow and as backup for commercial paper borrowings. The revolving credit facility represents commitments by the participating banks to make loans and, in certain cases, to issue letters of credit. The Company is required to make certain representations to the banks each time it requests an advance under the credit facility. However, in the event certain circumstances occur that could result in a material adverse change in the business, financial condition, or results of operations of PGE, the Company may not be able to make such representations, in which case the banks would not be required to lend. PGE is also subject to the risk that one or more of the participating banks may default on their obligation to make loans under the credit facility.

Adverse capital market performance could result in reductions in the fair value of benefit plan assets and increase the Company's liabilities related to such plans. Sustained declines in the fair value of the plans' assets could result in significant increases in funding requirements, which could adversely affect PGE's liquidity and results of operations.

Performance of the capital markets affects the value of assets that are held in trust to satisfy future obligations under PGE's defined benefit pension and other postretirement plans. Sustained adverse market performance could result in lower rates of return for these assets than projected by the Company and could increase PGE's funding requirements related to the plans. Additionally, changes in interest rates affect PGE's liabilities under the plans. As interest rates decrease, the Company's liabilities increase, potentially requiring additional funding.

Performance of the capital markets also affects the fair value of assets that are held in trust to satisfy future obligations under the Company's non-qualified employee benefit plans, which include deferred compensation plans. As changes in the fair value of these assets are recorded in current earnings, decreases can adversely affect the Company's operating results. In addition, such decreases can require that PGE make additional payments to satisfy its obligations under these plans.

The inability to attract and retain a qualified workforce, including senior management talent, and to maintain satisfactory collective bargaining agreements without prolonged labor disruptions, may adversely affect PGE's results of operations.

PGE's workforce includes a diverse mix of skilled professional, managerial and technical employees, including employees represented under collective bargaining agreements. Workforce management risks include the risk of turnover due to demographic challenges as employees approach retirement age. PGE also faces competition from other employers for key skills and experience within the industry or local geography. The Company also faces the risk of labor disruption due to the outcomes of labor negotiations or the possibility that employees not currently subject to collective bargaining agreements may organize.

Development of alternative technologies may negatively impact the value of PGE's generation facilities.

A basic premise of PGE's business is that generating electricity at central generation facilities achieves economies of scale and produces electricity at a relatively low price. Many companies and organizations conduct research and development activities to seek improvements in alternative technologies and distributed generation. It is possible that advances in such technologies, or other current technologies, will reduce the cost of alternative methods of electricity production to a level that is equal to or below that of central thermal and wind generation facilities. Such a development could limit the Company's future growth opportunities and limit growth in demand for PGE's electric service.

Operational changes required to comply with both existing and new environmental laws related to fish and wildlife could adversely affect PGE's results of operations.

A portion of PGE's total energy requirement is supplied with power generated from hydroelectric and wind generating resources. Operation of these facilities is subject to regulation related to the protection of fish and wildlife. The listing of various plants and species of fish, birds, and other wildlife as threatened or endangered has resulted in significant operational changes to these projects. Salmon recovery plans could include further major operational changes to the region's hydroelectric projects, including those owned by PGE and those from which the Company purchases power under long-term contracts. In addition, laws relating to the protection of migratory birds and other wildlife could impact the development and operation of transmission and distribution lines and wind projects. Also, new interpretations of existing laws and regulations could be adopted or become applicable to such facilities, which could further increase required expenditures for salmon recovery and endangered species protection and reduce the availability of hydroelectric or wind generating resources to meet the Company's energy requirements.

PGE could be vulnerable to cyber security attacks, data security breaches, acts of terrorism, or other similar events that could disrupt its operations, require significant expenditures, or result in claims against the Company.

In the normal course of business, PGE collects, processes, and retains sensitive and confidential customer and employee information, as well as proprietary business information, and operates systems that directly impact the availability of electric power and the transmission of electric power in its service territory. Despite the security measures in place, the Company's systems, and those of third-party service providers, could be vulnerable to cyber security attacks, data security breaches, acts of terrorism, or other similar events that could disrupt operations or result in the release of sensitive or confidential information. Such events could cause a shutdown of service or expose PGE to liability. In addition, the Company may be required to expend significant capital and other resources to protect against security breaches or to alleviate problems caused by security breaches. PGE maintains insurance coverage against some, but not all, potential losses resulting from these risks. However, insurance may not be adequate to protect the Company against liability in all cases. In addition, PGE is subject to the risk that insurers will dispute or be unable to perform their obligations to the Company.

Storms, earthquakes, wildfires, and other natural disasters could damage the Company's facilities and disrupt delivery of electricity resulting in significant property loss, repair costs, and reduced customer satisfaction.

PGE has exposure to natural disasters that can cause significant damage to its generation, transmission, and distribution facilities. Such events can interrupt the delivery of electricity, increase repair and service restoration expenses, and reduce revenues. Such events, if repeated or prolonged, can also affect customer satisfaction and the level of regulatory oversight. As a regulated utility, the Company is required to provide service to all customers within its service territory and generally has been afforded liability protection against customer claims related to service failures beyond the Company's reasonable control.

PGE is subject to extensive regulation that affects the Company's operations and costs.

PGE is subject to regulation by the FERC, the OPUC, and by certain federal, state, and local authorities under environmental and other laws. Such regulation significantly influences the Company's operating environment and can have an effect on many aspects of its business. Changes to regulations are ongoing, and the Company cannot predict with certainty the future course of such changes or the ultimate effect that they might have on its business. However, changes in regulations could delay or adversely affect business planning and transactions, and substantially increase the Company's costs.

PGE business activities are concentrated in one region and future performance may be affected by events and factors unique to Oregon.

The Company's industry and geographic concentrations may increase exposure to risks arising from regional regulation or legislation, such as legislative action related to carbon emissions. These concentrations may also increase exposure to credit and operational risks due to counterparties, suppliers and customer being similarly affected by changing conditions.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

PGE's principal property, plant, and equipment are generally located on land owned by the Company or land under the control of the Company pursuant to existing leases, federal or state licenses, easements, or other agreements. In some cases, meters and transformers are located on customer property. The Indenture securing the Company's First

Mortgage Bonds (FMBs) constitutes a direct first mortgage lien on substantially all utility property and franchises, other than expressly excepted property.

Generating Facilities

The following are generating facilities owned by PGE as of December 31, 2019 (in MW):

Facility	Location	Net Capacity [1]
Wholly-owned:		
Natural Gas or Oil:		
Beaver	Clatskanie, Oregon	508
Carty	Boardman, Oregon	437
Port Westward Unit 1 (PW1)	Clatskanie, Oregon	411
Coyote Springs	Boardman, Oregon	249
Port Westward Unit 2 (PW2)	Clatskanie, Oregon	225
Wind:		
Biglow Canyon	Sherman County, Oregon	450
Tucannon River	Columbia County, Washington	267
Hydro:		
North Fork	Clackamas River	58
Faraday	Clackamas River	46
Oak Grove	Clackamas River	45
River Mill	Clackamas River	25
T.W. Sullivan	Willamette River	18
Jointly-owned [2]:		
Coal:		
Boardman [3]	Boardman, Oregon	518
Colstrip [4]	Colstrip, Montana	296
Hydro:		
Round Butte [5]	Deschutes River	230
Pelton [5]	Deschutes River	73
Net capacity		3,856

(1) Represents net capacity of generating unit as demonstrated by actual operating or test experience, net of electricity used in the operation of a given facility. For wind-powered generating facilities, nameplate ratings are used in place of net capacity. A generator's nameplate rating is its full-load capacity under normal operating conditions as defined by the manufacturer.
(2) Net capacity reflects PGE's ownership share.
(3) PGE operates Boardman and has a 90% ownership interest.
(4) PGE has a 20% ownership interest in the facility, which is operated by Talen Montana, LLC.
(5) PGE operates Pelton and Round Butte and has a 66.67% ownership interest.

PGE's hydroelectric projects are operated pursuant to FERC licenses issued under the FPA. The licenses for the hydroelectric projects on the three different rivers expire as follows: Clackamas River, 2055; Willamette River, 2035; and Deschutes River, 2055.

Transmission and Distribution

PGE owns or has contractual rights associated with transmission lines that deliver electricity from its generation facilities to its distribution system in its service territory and also to the Western Interconnection. As of December 31, 2019, PGE-owned electric transmission system consisted of 1,264 circuit miles as follows: 287 circuit miles of 500 kV line; 423 circuit miles of 230 kV line; and 554 miles of 115 kV line. The Company also has

27,755 circuit miles of distribution lines that deliver electricity to its customers. The Company also has an ownership interest in, and capacity on, the following:

- 15% of the Colstrip Transmission facilities from Colstrip to BPA's transmission system; and
- 20% of the Pacific Northwest Intertie, a 4,800 MW transmission facility between the John Day Substation near the Columbia River in northern Oregon, and Malin, Oregon, near the California border. The Pacific Northwest Intertie is used primarily for the transmission of interstate purchases and sales of electricity among utilities, including PGE.

In addition, the Company has contractual rights to the following transmission capacity:

- 3,670 MW of firm BPA transmission on BPA's system to PGE's service territory in Oregon; and
- 150 MW of firm BPA transmission from the Mid-Columbia projects in Washington to the northern end of the Pacific Northwest AC Intertie, near John Day, Oregon, 5 MW to Tucannon River, and 5 MW to Biglow Canyon.

ITEM 3. LEGAL PROCEEDINGS.

See Note 19, Contingencies in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data," for information regarding legal proceedings.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

PGE's common stock is traded on the NYSE under the ticker symbol "POR". As of February 4, 2020, there were 684 holders of record of PGE's common stock.

While the Company expects to pay regular quarterly dividends on its common stock, the declaration of any dividends is at the discretion of the Company's Board of Directors. The amount of any dividend declaration will depend upon factors that the Board of Directors deems relevant and may include, but are not limited to, PGE's results of operations and financial condition, future capital expenditures and investments, and applicable regulatory and contractual restrictions.

For information with respect to securities authorized for issuance under equity compensation plans, see Note 14, Stock-Based Compensation in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

ITEM 6. SELECTED FINANCIAL DATA.

The following consolidated selected financial data should be read in conjunction with Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 8.—"Financial Statements and Supplementary Data."

	Years Ended December 31,				
	2019	2018	2017	2016	2015
	(In millions, except per share amounts)				
Statement of Income Data:					
Total revenues	$ 2,123	$ 1,991	$ 2,009	$ 1,923	$ 1,898
Income from operations	353	346	380	340	318
Net income	214	212	187	193	172
Earnings per share—basic	2.39	2.38	2.10	2.17	2.05
Earnings per share—diluted	2.39	2.37	2.10	2.16	2.04
Dividends declared per common share	1.5175	1.4275	1.34	1.26	1.18
Statement of Cash Flows Data:					
Capital expenditures	606	595	514	584	598

	As of December 31,				
	2019	2018	2017	2016	2015
	(Dollars in millions)				
Balance Sheet Data:					
Total assets	$ 8,394	$ 8,110	$ 7,838	$ 7,527	$ 7,210
Total long-term debt	2,597	2,478	2,426	2,350	2,193
Total finance and operating lease obligations*	202	49	51	54	—
Total shareholders' equity	2,591	2,506	2,416	2,344	2,258
Common equity ratio	48.1%	49.8%	49.4%	49.4%	50.7%

* The balances as of December 31, 2018, 2017, 2016 and 2015 represent capital lease obligations under accounting standards codification (ASC) 840. The balance as of December 31, 2019 represents finance and operating lease obligations as a result of the adoption of ASU 2016-02, *Leases (Topic 842)*. For further information, see "Recently Adopted Accounting Pronouncements" in Note 2, Summary of Significant Accounting Policies and Note 17, Leases, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

Forward-Looking Statements

The information in this report includes statements that are forward-looking within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements include, but are not limited to, statements that relate to expectations, beliefs, plans, assumptions and objectives concerning future results of operations, business prospects, future loads, the outcome of litigation and regulatory proceedings, future capital expenditures, market conditions, future events or performance and other matters. Words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "plans," "predicts," "projects," "will likely result," "will continue," "should," or similar expressions are intended to identify such forward-looking statements.

Forward-looking statements are not guarantees of future performance and involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed. PGE's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis including, but not limited to, management's examination of historical operating trends and data contained either in internal records or available from third parties, but there can be no assurance that PGE's expectations, beliefs, or projections will be achieved or accomplished.

In addition to any assumptions and other factors and matters referred to specifically in connection with such forward-looking statements, factors that could cause actual results or outcomes for PGE to differ materially from those discussed in forward-looking statements include:

- governmental policies, legislative action, and regulatory audits, investigations and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of facilities and other assets, construction and operation of plant facilities, transmission of electricity, recovery of power costs and capital investments, and current or prospective wholesale and retail competition;
- economic conditions that result in decreased demand for electricity, reduced revenue from sales of excess energy during periods of low wholesale market prices, impaired financial stability of vendors and service providers and elevated levels of uncollectible customer accounts;
- changing customer expectations and choices that may reduce customer demand for our services which may impact PGE's ability to make and recover its investments through rates and earn its authorized return on equity, including the impact of growing distributed and renewable generation resources, changing customer demand for enhanced electric services, and an increasing risk that customers procure electricity from community choice aggregators;
- the outcome of legal and regulatory proceedings and issues including, but not limited to, the matters described in Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data" of this Annual Report on Form 10-K;
- unseasonable or extreme weather and other natural phenomena, which could affect customers' demand for power and PGE's ability and cost to procure adequate power and fuel supplies to serve its customers, and could increase the Company's costs to maintain its generating facilities and transmission and distribution systems;
- operational factors affecting PGE's power generating facilities, including forced outages, hydro and wind conditions, and disruption of fuel supply, any of which may cause the Company to incur repair costs or purchase replacement power at increased costs;
- complications arising from PGE's jointly-owned generating facilities, including changes in ownership, adverse regulatory outcomes or operational failures that result in legal or environmental liabilities or unanticipated costs related to replacement power or repair costs
- the failure to complete capital projects on schedule and within budget or the abandonment of capital projects, either of which could result in the Company's inability to recover project costs;
- volatility in wholesale power and natural gas prices, which could require PGE to issue additional letters of credit or post additional cash as collateral with counterparties pursuant to power and natural gas purchase agreements;
- changes in the availability and price of wholesale power and fuels, including natural gas and coal, and the impact of such changes on the Company's power costs;
- capital market conditions, including availability of capital, volatility of interest rates, reductions in demand for investment-grade commercial paper, as well as changes in PGE's credit ratings, any of which could have an impact on the Company's cost of capital and its ability to access the capital markets to support requirements for working capital, construction of capital projects, and the repayments of maturing debt;
- future laws, regulations, and proceedings that could increase the Company's costs of operating its thermal generating plants, or affect the operations of such plants by imposing requirements for additional emissions controls or significant emissions fees or taxes, particularly with respect to coal-fired generating facilities, in order to mitigate carbon dioxide, mercury and other gas emissions;
- changes in, and compliance with, environmental laws and policies, including those related to threatened and endangered species, fish, and wildlife;

- the effects of climate change, including changes in the environment that may affect energy costs or consumption, increase the Company's costs, or adversely affect its operations;
- changes in residential, commercial, and industrial customer growth, and in demographic patterns, in PGE's service territory;
- the effectiveness of PGE's risk management policies and procedures;
- cyber security attacks, data security breaches, or other malicious acts that cause damage to the Company's generation and transmission facilities or information technology systems, or result in the release of confidential customer, employee, or Company information;
- employee workforce factors, including potential strikes, work stoppages, transitions in senior management, and the ability to recruit and retain appropriate talent;
- new federal, state, and local laws that could have adverse effects on operating results;
- political and economic conditions;
- natural disasters and other risks, such as earthquake, flood, drought, lightning, wind, and fire;
- changes in financial or regulatory accounting principles or policies imposed by governing bodies; and
- acts of war or terrorism.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by law, PGE undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all such factors or assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.

Overview

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide an understanding of the business environment, results of operations, and financial condition of PGE. MD&A should be read in conjunction with the Company's consolidated financial statements contained in this report, and other periodic and current reports filed with the SEC.

PGE is a vertically-integrated electric utility engaged in the generation, transmission, distribution, and retail sale of electricity in the state of Oregon, as well as the wholesale purchase and sale of electricity and natural gas in order to meet the needs of its retail customers. The Company generates revenues and cash flows primarily from the sale and distribution of electricity to retail customers in its service territory. In addition, the Company participates in the wholesale market by purchasing and selling electricity and natural gas in an effort to obtain reasonably-priced power for its retail customers.

PGE is committed to continuing to achieve steady growth and returns as the Company transforms to meet the challenges of climate change and an ever-evolving energy grid. Customers, policy makers, and other stakeholders expect PGE to reduce greenhouse gas emissions, keep the power grid reliable and secure, and ensure prices are affordable, especially for the most vulnerable customers. The Company's strategy strives to balance these interests. PGE plans to:

- Decarbonize the power supply with a goal of more than 80% carbon reduction from 1990 levels by the year 2050;
- Electrify sectors of the economy like transportation and buildings that are also transforming to reduce greenhouse gas emissions; and

- Perform as a business, driving improvements to work efficiency, safety of our coworkers, and reliability of our systems and equipment all while adhering to the Company's earnings per diluted share growth guidance of 4-6% on average.

Decarbonize the power supply—PGE partners with customers and local and state governments to advance a clean energy future. PGE continues to leverage these partnerships to pursue emission reductions using a diverse portfolio of clean and renewable energy resources, and promote economy-wide emission reductions through electrification and smart energy use to help the state meet its greenhouse gas reduction goals.

PGE's framework for achieving a clean energy future is informed and enabled by: i) customer choice programs; ii) carbon legislation; iii) the resource planning process; and iv) the renewable cost recovery framework.

Customer Choice Programs—PGE's customers continue to express a commitment to purchasing clean energy, as over 225,000 customers voluntarily participate in PGE's Green Future Program, the largest renewable power program by participation in the nation. In 2017, Oregon's most populous city, Portland, and most populous county, Multnomah, each passed resolutions to achieve 100 percent clean and renewable electricity by 2035 and 100 percent economy-wide clean and renewable energy by 2050. Other jurisdictions in PGE's service area continue to consider similar goals.

In response, the Company has implemented a new customer product option, the Green Future Impact program, which allows for 100 megawatts (MW) of PGE-provided power purchase agreements for renewable resources and up to 200 MW of customer-provided renewable resources. Approved by the OPUC in the first quarter 2019, the program will provide business customers access to bundled renewable attributes from those resources. Through this voluntary program, the Company seeks to align sustainability goals, cost and risk management, reliable integrated power, and a cleaner energy system.

Pursuant to the OPUC order approving the Green Future Impact tariff, program subscribers remain cost of service customers, and pay both the cost of service tariff price and the price under the renewable energy option tariff. This structure is intended to avoid stranded costs and cost shifting.

Carbon Legislation—SB 1547 set a benchmark for how much electricity must come from renewable sources like wind and solar (50 percent by 2040) and requires the elimination of coal from Oregon utility customers' energy supply no later than 2030 (subject to an exception that allows extension of this date until 2035 for PGE's output from Colstrip).

Other future effects under the law include:

- An increase in RPS thresholds to 27% by 2025, 35% by 2030, 45% by 2035, and 50% by 2040;
- A limitation on the life of RECs generated from facilities that become operational after 2022 to five years, but continued unlimited lifespan for all existing RECs and allowance for the generation of additional unlimited RECs for a period of five years for projects online before December 31, 2022; and
- An allowance for energy storage costs related to renewable energy in the Company's Renewable Adjustment Clause (RAC) filings.

In response to SB 1547, the Company filed a tariff request in 2016 to accelerate recovery of PGE's investment in the Colstrip facility from 2042 to 2030. During 2019, the owners of Colstrip Units 1 and 2 announced that they would permanently close those two units and have retired them as of January 2020. Although PGE has no direct ownership interest in those two units, the Company does have a 20% ownership share in Colstrip Units 3 and 4, which utilize certain common facilities with Units 1 and 2.

Although PGE is currently scheduled to recover the costs of Colstrip by 2030, some co-owners of Units 3 and 4 have taken actions to recover their costs by 2025 and 2027. The Company continues to evaluate its ongoing investment in Colstrip.

Any reduction in generation from Colstrip has the potential to provide capacity on the Colstrip transmission line, which stretches from eastern Montana to near the western end of the state to serve markets in the Pacific Northwest and beyond. PGE has an ownership interest in, and capacity on, 15% of the Colstrip Transmission facilities. Renewable energy development in the state of Montana could benefit from any excess transmission capacity that may become available.

The Company continues with plans to cease coal-fired operation at its Boardman generating plant at the end of 2020.

During the 2019 State legislative session, House Bill (HB) 2020 was introduced, which would have authorized a comprehensive cap and trade package in the State and would have granted the OPUC direct authority to address climate change. Although HB 2020 was not enacted in 2019, an amended version has been reintroduced in the 35-day legislative session, which began on February 3, 2020. The new proposal, Senate Bill (SB) 1530, is also a cap and trade package that includes changes made to address concerns raised by various parties. Prior to the legislative session, the OPUC stated that it would continue to collaborate with the legislature and stakeholders to make progress on climate change, noting that their authority is limited to that of an economic regulator. The Company will continue to monitor this legislative effort.

The Resource Planning Process—PGE's planning process includes working with customers, stakeholders, and regulators to chart the course toward a clean, affordable, and reliable energy future. This process includes consideration of customer expectations and legislative mandates to move away from fossil fuel generation and toward renewable sources of energy.

In May 2018 the Company issued a request for proposals seeking to procure approximately 100 average MW (MWa) of qualifying renewable resources. The prevailing bid, Wheatridge Renewable Energy Facility (Wheatridge), will be an energy facility in eastern Oregon that combines 300 MW of wind generation and 50 MW of solar generation with 30 MW of battery storage.

PGE will own 100 MW of the wind resource with an investment of approximately $160 million. Subsidiaries of NextEra Energy Resources, LLC will own the balance of the 300 MW wind resource, along with the solar and battery components, and sell their portion of the output to PGE under 30-year power purchase agreements. PGE has the option to purchase the underlying assets of the power purchase agreements on the 12th anniversary of the commercial operation date of the wind facility. As of December 31, 2019, the Company has recorded $17 million, including the allowance for funds used during construction (AFDC), in construction work-in-progress (CWIP) related to Wheatridge.

The wind component of the facility is expected to be operational by December 2020 and qualify for PTCs at the 100 percent level. Construction of the solar and battery components is planned for 2021 and is also expected to qualify for federal investment tax credits.

In July 2019, PGE submitted its 2019 Integrated Resource Plan (2019 IRP) to the OPUC. The initial plan and modifications proposed by PGE within the docket (LC 73) would set forth the following actions the Company would undertake over the next four years to acquire the resources identified:

- Customer actions—
  - cost-effective energy efficiency
  - reliance on demand response, and
  - dispatchable customer storage and standby generation.
- Renewable actions—a Renewable RFP seeking up to 150 MWa to come online by the end of 2024 and contribute to meeting capacity needs; and

- Capacity actions—a concurrent procurement process that will allow PGE to pursue cost-competitive agreements for existing capacity in the region and to conduct a non-emitting Capacity RFP seeking new dispatchable resources.

Through the renewable and capacity actions, PGE seeks up to approximately 150 MWa of additional non-emitting energy resources and up to approximately 700 MW of capacity contribution from a combination of renewables, existing resources, and new non-emitting dispatchable capacity resources, such as energy storage.

The regulatory schedule for the 2019 IRP would lead to an OPUC order in the first quarter of 2020.

Renewable Recovery Framework—As previously authorized by the OPUC, the RAC allows PGE to recover prudently incurred costs of renewable resources through filings made by April 1st each year. In the 2019 General Rate Case (2019 GRC) Order, the OPUC authorized the inclusion of prudent costs of energy storage projects associated with renewables in future RAC filings to be made to the OPUC, under certain conditions. Although no significant filings have been submitted under the RAC during 2018, the Company did submit a RAC filing for Wheatridge in the fourth quarter of 2019.

Electrify other sectors of the economy—PGE is working toward an equitable, safe, and clean energy future. Recent and future enhancements to the grid to enable a seamless platform include:

- The use of electricity in more applications such as electric vehicles and heat pumps;
- The integration of new, geographically-diverse energy markets;
- The deployment of new technologies like energy storage, communications networks, automation and control systems for flexible loads, and distributed generation;
- The development of connected neighborhood microgrids and smart communities; and
- The use of data and analytics to better predict demand and support energy saving customer programs.

In July 2019, PGE's Board approved plans to construct an Integrated Operations Center (IOC) as a key step to supporting this strategy, at an estimated total cost of $200 million, excluding AFDC. The IOC will centralize mission-critical operations, including those that are planned as part of the integrated grid strategy. This secure, resilient facility will include infrastructure to support and enhance grid operations and co-locate primary support functions. As of December 31, 2019, the Company has recorded $30 million, including AFDC, in CWIP related to the IOC.

The Company is also working to advance transportation electrification, with projects aimed at improving accessibility to electric vehicle charging stations and partnering with local mass transit agencies to transition to a greater use of electric vehicles. In June 2019, the Legislature enacted Senate Bill 1044, which establishes Oregon's zero emissions vehicle goals in statute at 250,000 vehicle sales by 2025 and 95% of all vehicle sales by 2035. In September 2019, PGE filed with the OPUC its first Transportation Electrification plan, which considers current and planned activities, along with both existing and potential system impacts, in relation to the State's carbon reduction goals.

In 2018, PGE filed an energy storage proposal that called for 39 MW of storage to be developed over the next several years at various locations across the grid. In August 2018, the OPUC issued an order that outlined an agreed approach to the development of five energy storage projects by PGE with an expected capital cost of approximately $45 million.

Perform as a business—PGE focuses on providing reliable, clean power to customers at affordable prices while providing a fair return to investors. To achieve this goal the Company must execute effectively within its regulatory framework and maintain prudent management of key financial, regulatory, and environmental matters that may affect customer prices and investor returns. The following discussion provides detail on several such material matters:

General Rate Case—In 2018, PGE filed with the OPUC a general rate case based on a 2019 test year. The filing sought recovery of costs related to better serving customers and building a smarter, more resilient system and included the expectation of higher net variable power costs in 2019.

In December 2018, the OPUC issued an order that, when combined with customer credits and the effects of tax reform, would result in an overall annual increase in PGE's revenues of $9 million, effective January 1, 2019. In addition, the OPUC approved a capital structure of 50% debt and 50% equity, a return on equity of 9.50%, a cost of capital of 7.30%, and rate base of $4.75 billion.

The general rate case filings, as well as copies of the orders, direct testimony, exhibits, and stipulations are available on the OPUC website at www.oregon.gov/puc.

Power Costs—Pursuant to the AUT process, PGE annually files an estimate of power costs for the following year. As approved by the OPUC in December 2018, the 2019 GRC included a final projected increase in power costs for 2019, and a corresponding increase in annual revenue requirement, of $25 million from 2018 levels, which was reflected in customer prices effective January 1, 2019. The filing for the 2020 AUT indicated that power costs are expected to rise in 2020 by $27 million.

Under the PCAM for 2019, NVPC was within the limits of the deadband, thus no potential refund or collection was recorded. The OPUC will review the results of the PCAM for 2019 during the second half of 2020 with a decision expected in the fourth quarter 2020.

Portland Harbor Environmental Remediation Account (PHERA) Mechanism—The EPA has listed PGE as one of over one hundred PRPs related to the remediation of the Portland Harbor Superfund site. As of December 31, 2019, significant uncertainties still remain concerning the precise boundaries for clean-up, the assignment of responsibility for clean-up costs, the final selection of a proposed remedy by the EPA, and the method of allocation of costs amongst PRPs. It is probable that PGE will share in a portion of these costs. In a Record of Decision issued in 2017, the EPA outlined its selected remediation plan for clean-up of the Portland Harbor site, which had an estimated total cost of $1.7 billion, However, the Company does not currently have sufficient information to reasonably estimate the amount, or range, of its potential costs for investigation or remediation of Portland Harbor, although such costs could be material to PGE's financial position. The impact of such costs to the Company's results of operations is mitigated by the PHERA mechanism. As approved by the OPUC, the Company's environmental recovery mechanism allows the Company to defer and recover incurred environmental expenditures related to the Portland Harbor Superfund Site through a combination of third-party proceeds, such as insurance recoveries, and customer prices, as necessary. The mechanism established annual prudency reviews of environmental expenditures and third-party proceeds, and annual expenditures in excess of $6 million, excluding contingent liabilities, are subject to an annual earnings test. PGE's results of operations may be impacted to the extent such expenditures are deemed imprudent by the OPUC or disallowed per the prescribed earnings test. For further information regarding the PHERA mechanism, see "EPA Investigation of Portland Harbor" in Note 19, Contingencies in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

City of Portland Audit—In 2019, the city of Portland (the "City"), which is the largest city within PGE's service territory, completed its audit of PGE's and the City's mutual License Fees agreement for the 2012 through 2015 periods. The preliminary claim by the City is that PGE improperly excluded certain items from the calculation of gross revenues, which resulted in underpayment of franchise taxes of $7 million, including interest and penalties. PGE believes the City's preliminary findings are not consistent with previous audit conclusions, which found that the Company appropriately calculated gross revenues in determining franchise fees. PGE believes it has good standing for maintaining the historical approach to determining License Fees and has not recorded a liability for the City's assertion. The City has not provided its Final Letter of Determination, which is an initial step in an ongoing resolution process.

Capital Project Deferral—In the second quarter of 2018, PGE placed into service a new customer information system at a total cost of $152 million. In accordance with agreements reached with stakeholders in the Company's

2019 GRC, the Company's capital cost of the asset is included in rate base and customer prices as of January 1, 2019.

Consistent with past regulatory precedent, in May 2018, the Company submitted an application to the OPUC to defer the revenue requirement associated with this new customer information system from the time the system went into service through the end of 2018. As a result, PGE began deferring its incurred expenses, primarily related to depreciation and amortization, of the new customer information system once it was placed in service.

In 2017, the OPUC opened docket UM 1909 to conduct an investigation of the scope of its authority under Oregon law to allow the deferral of costs related to capital investments for later inclusion in customer prices. In October 2018, the OPUC issued Order 18-423 (Order) concluding that the OPUC lacks authority under Oregon law to allow deferrals of any costs related to capital investments. In the Order, the OPUC acknowledged that this decision is contrary to its past limited practice of allowing deferrals related to capital investments and will require adjustments to its regulatory practices. The OPUC directed its Staff to meet with the utilities and stakeholders to address the full implications of this decision, and to propose recommendations needed to implement this decision consistent with the OPUC's legal authority and the public interest.

In response to the Order, PGE and other utilities filed a motion for reconsideration and clarification, which was denied. On April 19, 2019, PGE and the other utilities filed a petition for judicial review of the OPUC Order with the Oregon Court of Appeals. While procedural steps pursuant to this petition continue, PGE believes that the costs incurred to date associated with the customer information system were prudently incurred and has not withdrawn its deferral application to recover the revenue requirement of this capital project.

During 2018, PGE deferred a total of $12 million of expenses related to the customer information system. However, the Order has impacted the probability of recovery of deferred expenses and, as such, the Company has recorded a reserve for the full amount of the costs related to the customer information system. The reserve was established with an offsetting charge to the results of operations in 2018. Any amounts that may ultimately be approved by the OPUC in subsequent proceedings would be recognized in earnings in the period of such approval; however, there is no assurance that such recovery would be granted by the OPUC.

Decoupling—The decoupling mechanism, authorized by the OPUC through 2022, is intended to provide for recovery of margin lost as a result of a reduction in electricity sales attributable to energy efficiency, customer-owned generation, and conservation efforts by residential and certain commercial customers. The mechanism provides for collection from (or refund to) customers if weather-adjusted use per customer is less (or more) than that projected in the Company's most recent general rate case.

The Company recorded an estimated collection of $14 million attributed to the year ended December 31, 2019, which resulted from variances between actual weather-adjusted use per customer and that projected in the 2019 GRC. Collections under the decoupling mechanism are subject to an annual limitation of 2% of the applicable tariff schedule. For 2019, this limitation would have been, in total, $27 million for residential and commercial customers now subject to the decoupling mechanism. Any collection from customers for the 2019 year is expected to occur over a one-year period, which would begin January 1, 2021.

The Company recorded a deferral for an estimated collection of $2 million during the year ended December 31, 2018, as a result of variances from amounts established in the 2018 GRC. Collection for the 2018 year is expected to occur over a one-year period, which began January 1, 2020.

Storm Restoration Costs—Beginning in 2011, the OPUC authorized the Company to collect $2 million annually from retail customers to cover incremental expenses related to major storm damages, and to defer any amount not utilized in the current year. Under the 2019 GRC, the annual collection amount increased to $4 million beginning in 2019. Due to a series of storm events in the first half of 2017, the Company exhausted the storm collection authorized for 2017. Consequently, PGE was exposed to the incremental costs related to such major storm events, which totaled $9 million, net of the amount collected in 2017.

As a result of the additional costs incurred, PGE filed an application with the OPUC requesting authorization to defer incremental storm related restoration costs from the date of the application, in the first quarter of 2017, through the end of 2017. In the third quarter of 2019, the OPUC issued an order that denied the Company's application for deferral. Although PGE had deferred the incremental expense in 2017, an offsetting reserve was also recorded at that time, thus the OPUC decision had no impact to the Company's current results of operations.

Corporate Activity Tax—In 2019, the State enacted HB 3427, which imposes a new gross receipts tax on companies with annual revenues in excess of $1 million and will apply to tax years beginning on or after January 1, 2020. The legislation defines that the tax will apply to commercial activities sourced in Oregon, less a deduction for 35% of the greater of "cost inputs" or "labor costs." The resulting amount will be taxed at 0.57%.

In anticipation of the incremental annual expense as a result of this new tax, PGE submitted a tariff filing with the OPUC in the fourth quarter 2019 to establish a balancing account and provide for an estimated recovery of $7 million in customer prices in 2020. The Company expects to revisit the expected tax consequences annually and revise the annual tariff accordingly. On January 29, 2020. the OPUC issued an order approving the tariff and the associated deferral, balancing account, and automatic adjustment clause, with the provision that it be included in base rates at a future date to be agreed upon by the parties.

The discussion that follows in this MD&A provides additional information related to the Company's operating activities, legal, regulatory, and environmental matters, results of operations, and liquidity and financing activities.

Operating Activities—As an electric utility, PGE closely follows and plans for customer demand in its service territory as it strives to meet the needs and expectations of its retail customers through the generation of power from its own facilities or purchase of power in the wholesale market.

Customers and Demand—The impact of seasonal weather conditions on demand for electricity can cause the Company's revenues, cash flows, and income from operations to fluctuate from period to period. See the *Seasonality* section of "Customers and Revenues" within Item 1. Business for further information regarding seasonal fluctuations.

In 2019, retail energy deliveries increased 1.2% from 2018 as industrial deliveries continued to grow. Residential customer deliveries, which are most sensitive to fluctuations in weather, also increased slightly, as 2019 saw cooler temperatures during the heating season partially offset by fewer cooling degree-days during the summer cooling season, while commercial customer deliveries decreased. For 2019 and 2018, the average number of retail customers and deliveries, by customer type, were as follows:

	2019		2018		Increase/ (Decrease) in Energy Deliveries
	Average Number of Customers	Energy Deliveries *	Average Number of Customers	Energy Deliveries *	
Residential	779,673	7,471	772,389	7,416	0.7 %
Commercial (PGE sales only)	109,521	6,653	108,570	6,783	(1.9)%
Direct Access	563	665	537	647	2.8 %
Total Commercial	110,084	7,318	109,107	7,430	(1.5)%
Industrial (PGE sales only)	193	3,181	203	2,987	6.5 %
Direct Access	69	1,490	67	1,389	7.3 %
Total Industrial	262	4,671	270	4,376	6.7 %
Total (PGE sales only)	889,387	17,305	881,162	17,186	0.7 %
Total Direct Access	632	2,155	604	2,036	5.8 %
Total	890,019	19,460	881,766	19,222	1.2 %

* In thousands of MWh.

In 2019, heating degree-days, an indication of electricity use for heating, were 1% above the 15-year average and 13% higher than 2018. Cooling degree-days, a similar indication of the extent to which customers are likely to have used electricity for cooling, although 6% above the 15-year moving average, were 18% below the 2018 levels.

Residential energy deliveries were 0.7% higher in 2019 than 2018, driven by a 0.9% increase in the average number of customers. Weather impacted residential deliveries as it served to increase comparable deliveries during the heating season and reduce comparable deliveries during the summer season. See *"Revenues"* in the 2019 Compared to 2018 section of Results of Operations within this Item 7, for further information on heating and cooling degree days.

Commercial energy deliveries declined in several sectors including food and merchandise stores and government and education. Irrigation deliveries were also lower in 2019, which saw a relatively mild summer, than 2018, which had an unusually hot and dry summer irrigation season.

The 6.7% increase in industrial energy deliveries is due to continued strength in the high-tech manufacturing sector as well as the reopening in 2019 of a large paper facility that had closed in late 2017.

On a weather-adjusted basis, total retail deliveries increased 0.1% from 2018. The increase was driven by 6.8% growth in industrial energy deliveries which were largely offset by decreases in residential and commercial energy deliveries of 1.9% and 1.6% respectively. Average usage per customer for smaller energy users continues to decline, driven by ongoing market and program-based energy efficiency gains. PGE projects that retail energy deliveries for 2020 will be approximately 0.5% - 1.5% above 2019 weather-adjusted levels, reflecting strength in industrial deliveries, partially offset by continued energy efficiency and conservation efforts.

ESSs supplied Direct Access customers with energy representing 11% of the Company's total retail energy deliveries during 2019 and 2018. The maximum retail load allowed to be supplied under the fixed three-year and minimum five-year opt-out programs represent 14% of the Company's total retail energy deliveries for 2019, and 2018. With the adoption of the New Large Load Direct Access program, the percentage of the Company's energy deliveries supplied by ESSs is expected to increase by as much as 6%.

Energy efficiency and conservation efforts by retail customers influence demand, although the financial effects of such efforts by residential and certain commercial customers are mitigated by the decoupling mechanism, which is intended to provide for recovery of margin lost as a result of a reduction in electricity sales attributable to energy efficiency and conservation efforts. The mechanism provides for collection from (or refund to) customers if weather-adjusted use per customer is less (or more) than the projected baseline set in the Company's most recent approved general rate case. See *"Decoupling"* in this Overview section of Item 7, for further information on the decoupling mechanism.

Power Operations—PGE utilizes a combination of its own generating resources and wholesale market transactions to meet the energy needs of its retail customers. Based on numerous factors, including plant availability, customer demand, river flows, wind conditions, and current wholesale prices, the Company continuously makes economic dispatch decisions in an effort to obtain reasonably-priced power for its retail customers. PGE also purchases wholesale natural gas in the United States and Canada to fuel its generating portfolio and sells excess gas back into the wholesale market. As a result, the amount of power generated and purchased in the wholesale market to meet the Company's retail load requirement can vary from period to period and impacts NVPC and income from operations.

	Plant availability (1)		Actual energy provided compared to projected levels (2)		Actual energy provided as a percentage of total retail load	
	2019	2018	2019	2018	2019	2018
Generation:						
Thermal:						
Natural gas	92%	92%	86%	89%	45%	41%
Coal (3)	87	94	104	69	24	17
Wind	96	92	90	95	9	10
Hydro	93	93	81	96	8	8

(1) Plant availability represents the percentage of the year the plant was available for operations, which is impacted by planned maintenance and forced, or unplanned, outages.
(2) Projected levels of energy are included as part of PGE's AUT. Such projections establish the power cost component of retail prices for the following calendar year. Any shortfall is generally replaced with power from higher cost sources, while any excess generally displaces power from higher cost sources.
(3) Plant availability excludes Colstrip, which PGE does not operate. Colstrip availability was 85% in 2019, compared with 82% in 2018.

Energy received from PGE-owned and jointly-owned thermal plants increased 20% in 2019 compared to 2018, primarily as a result of increased economic dispatch at Boardman. Energy expected to be received from thermal resources is projected annually in the AUT based on forecast market prices, variable costs to run the plant, and the constraints of the plant. PGE's thermal generating plants require varying levels of annual maintenance, which is generally performed during the second quarter of the year.

Energy received from PGE-owned hydroelectric plants and under contracts from mid-Columbia hydroelectric projects decreased 20% in 2019 compared to 2018, due to less favorable hydro conditions in 2019. Energy expected to be received from hydroelectric resources is projected annually in the AUT based on a modified hydro study, which utilizes 80 years of historical stream flow data. See *"Purchased power and fuel"* section of Results of Operations in this Item 7, for further detail on regional hydro results.

Energy received from PGE-owned wind resources and under contracts decreased 8% in 2019 compared to 2018, due to less favorable wind conditions in 2019. Energy expected to be received from wind generating resources (Biglow Canyon and Tucannon River) is projected annually in the AUT based on historical generation. Wind generation forecasts are developed using a 5-year rolling average of historical wind levels or forecast studies when historical data is not available. As a result of the generation shortfalls, PTCs have not materialized to the extent contemplated in the Company's prices.

Under the PCAM, PGE may share with customers a portion of cost variances associated with NVPC. Subject to a regulated earnings test, customer prices can be adjusted annually to absorb a portion of the difference between the forecasted NVPC included in customer prices (baseline NVPC) and actual NVPC for the year, if such differences exceed a prescribed "deadband" limit, which ranges from $15 million below to $30 million above baseline NVPC. The following is a summary of the results of the Company's PCAM as calculated for regulatory purposes for 2019, and 2018:

- For 2019, actual NVPC was above baseline NVPC by $5 million, which was within the established deadband range. Accordingly, no estimated collection from customers was recorded as of December 31, 2019. A final determination regarding the 2019 PCAM results will be made by the OPUC through a public filing and review in 2020.
- For 2018, actual NVPC was below baseline NVPC by $3 million, which was within the established deadband range. Accordingly, no estimated refund to customers was recorded as of December 31, 2018. A final determination regarding the 2018 PCAM results was made by the OPUC through a public filing and review in 2019, which confirmed no refund to customers pursuant to the PCAM for 2018.

Results of Operations

The following tables provide financial and operational information to be considered in conjunction with management's discussion and analysis of results of operations.

PGE defines Gross margin as Total revenues less Purchased power and fuel. Gross margin is considered a non-GAAP measure as it excludes depreciation and amortization and other operation and maintenance expenses. The presentation of Gross margin is intended to supplement an understanding of PGE's operating performance in relation to changes in customer prices, fuel costs, impacts of weather, customer counts and usage patterns, and impact from regulatory mechanisms such as decoupling. The Company's definition of Gross margin may be different from similar terms used by other companies and may not be comparable to their measures.

The results of operations are as follows for the years presented (dollars in millions):

	Years Ended December 31,					
	2019		2018		2017	
	Amount	As % of Rev	Amount	As % of Rev	Amount	As % of Rev
Total revenues (1)	$ 2,123	100%	$ 1,991	100%	$ 2,009	100%
Purchased power and fuel (1)	614	29	571	30	592	30
Gross margin	1,509	71	1,420	70	1,417	70
Other operating expenses:						
Generation, transmission and distribution	323	15	292	15	309	16
Administrative and other	290	14	271	13	260	13
Depreciation and amortization	409	19	382	19	345	17
Taxes other than income taxes	134	6	129	6	123	6
Total other operating expenses	1,156	54	1,074	53	1,037	52
Income from operations	353	17	346	17	380	18
Interest expense, net (2)	128	6	124	6	120	6
Other income:						
Allowance for equity funds used during construction	10	—	11	1	12	1
Miscellaneous income (expense), net	6	—	(4)	—	1	—
Other income, net	16	—	7	1	13	1
Income before income taxes	241	11	229	12	273	13
Income tax expense	27	1	17	1	86	4
Net income	$ 214	10%	$ 212	11%	$ 187	9%

(1) As reported on PGE's Consolidated Statements of Income.

(2) Includes an allowance for borrowed funds used during construction of $5 million in 2019 and $6 million in 2018 and 2017.

Revenues, energy deliveries (presented in MWh), and average number of retail customers consist of the following for the years presented:

	Years Ended December 31,					
	2019		2018		2017	
Revenues[1] (dollars in millions):						
Retail:						
Residential	$ 981	46%	$ 948	48%	$ 969	48%
Commercial	636	30	647	32	652	32
Industrial	196	9	185	9	192	10
Direct Access	44	2	43	2	37	2
Subtotal	1,857	87	1,823	91	1,850	92
Alternative revenue programs, net of amortization	2	—	3	—	—	—
Other accrued (deferred) revenues, net[2]	22	2	(45)	(2)	10	1
Total retail revenues	1,881	89	1,781	89	1,860	93
Wholesale revenues	170	8	159	8	105	5
Other operating revenues	72	3	51	3	44	2
Total revenues	$ 2,123	100%	$ 1,991	100%	$ 2,009	100%
Energy deliveries (MWh in thousands):						
Retail:						
Residential	7,471	31%	7,416	31%	7,880	34%
Commercial	6,653	28	6,783	29	6,932	30
Industrial	3,181	13	2,987	13	2,943	13
Subtotal	17,305	72	17,186	73	17,755	77
Direct access:						
Commercial	665	3	647	3	623	3
Industrial	1,490	6	1,389	6	1,340	6
Subtotal	2,155	9	2,036	9	1,963	9
Total retail energy deliveries	19,460	81	19,222	82	19,718	86
Wholesale energy deliveries	4,669	19	4,290	18	3,193	14
Total energy deliveries	24,129	100%	23,512	100%	22,911	100%
Average number of retail customers:						
Residential	779,673	88%	772,389	88%	762,211	88%
Commercial	109,521	12	108,570	12	107,364	12
Industrial	193	—	203	—	199	—
Direct access	632	—	604	—	559	—
Total	890,019	100%	881,766	100%	870,333	100%

(1) Includes both revenues from customers who purchase their energy supplies from the Company and revenues from the delivery of energy to those customers that purchase their energy from ESSs. Commercial revenues from ESS customers were $18 million for 2019 and 2018, and $17 million for 2017. Industrial revenues from ESS customers were $26 million, $25 million, and $20 million for 2019, 2018, and 2017, respectively.

(2) Amounts for the years ended December 31, 2019 and 2018 are primarily comprised of $23 million of amortization and $45 million of deferral, respectively, related to the 2018 net tax benefits due to the change in corporate tax rate under the United States Tax Cuts and Jobs Act of 2017 (TCJA).

PGE's sources of energy, total system load, and retail load requirement for the years presented are as follows:

	Years Ended December 31,					
	2019		2018		2017	
Sources of energy (MWh in thousands):						
Generation:						
Thermal:						
Natural gas	8,342	36%	7,515	33%	6,228	28%
Coal	4,416	19%	3,106	14	3,344	15
Total thermal	12,758	55	10,621	47	9,572	43
Hydro	1,407	6	1,474	7	1,774	8
Wind	1,706	8	1,875	8	1,641	8
Total generation	15,871	69	13,970	62	12,987	59
Purchased power:						
Term	5,882	25	6,714	30	7,192	33
Hydro	1,048	5	1,603	7	1,648	7
Wind	284	1	286	1	264	1
Total purchased power	7,214	31	8,603	38	9,104	41
Total system load	23,085	100%	22,573	100%	22,091	100%
Less: wholesale sales	(4,669)		(4,290)		(3,193)	
Retail load requirement	18,416		18,283		18,898	

Net income for the year ended December 31, 2019 was $214 million, or $2.39 per diluted share, compared with $212 million, or $2.37 per diluted share, for the year ended December 31, 2018. Among the factors that led to the $2 million, or 1%, increase in net income was Gross margin, which increased $89 million primarily due to a $132 million increase in revenues, driven by higher retail prices as a result of the 2019 GRC and other supplemental tariffs. Partially offsetting the revenue increase was a $43 million increase in Purchased power and fuel expense, as a result of a $46 million increase in the cost of purchased power. Although purchased power volumes were lower due to economic dispatch decisions, the resulting savings were diminished by the increased expenses associated with higher utilization of Company-owned generation. Largely offsetting the increase in Gross margin were Operating expense increases of $82 million, which included $27 million higher depreciation and amortization expense resulting from capital additions, a $13 million increase in distribution expenses due to higher vegetation management and wildfire mitigation efforts, $13 million higher labor and benefit expenses, a $10 million gain from the cash settlement of Carty litigation in 2018 that did not recur, and a $10 million increase in income tax expense.

2019 Compared to 2018

Total revenues increased $132 million, or 6.6%, in 2019 compared with 2018 as a result of the items discussed below.

Total retail revenues increased $100 million, or 5.6%, in 2019 compared with 2018, primarily due to the net effect of:

- $66 million as a result of customer price changes in the 2019 GRC, the AUT, and the amortization in prices of the decoupling mechanism;
- $23 million that resulted from the 1.2% overall increase in retail energy deliveries consisting of a 0.7% increase in residential deliveries, and a 6.7% increase in industrial deliveries, partially offset by a 1.5% decrease in commercial deliveries. The effects of weather on electricity demand is reflected predominantly in the Residential revenue line in the table above. The table below shows that 2019 had more heating degree days than 2018 during the heating season, although the effect was partially offset by the relative lack

of cooling degree-days during the summer months in 2019. For further information on customer demand, see *"Customers and Demand"* in the Overview section of this Item 7; and

- $12 million resulting from the combination of various supplemental tariffs and adjustments, the largest of which pertain to the demand response pilot program and a major maintenance expense deferral, which was offset in Generation, transmission and distribution expense.

Total heating degree-days in 2019 were slightly above the 15-year average and up considerably from total heating degree-days in 2018. Total cooling degree-days in 2019 exceeded the 15-year average by 6% although were 18% below the 2018 total. The following table presents the number of heating and cooling degree-days in 2019 and 2018, along with the 15-year averages, reflecting that weather had a considerable influence on comparative energy deliveries:

	Heating Degree-Days			Cooling Degree-Days		
	2019	**2018**	**15-Year Average**	**2019**	**2018**	**15-Year Average**
1st quarter	1,992	1,766	1,830	—	—	—
2nd quarter	467	471	653	102	116	88
3rd quarter	83	69	75	462	575	440
4th quarter	1,623	1,396	1,582	—	1	3
Total	4,165	3,702	4,140	564	692	531
Increase (decrease) from the 15-year average	1%	(11)%		6%	30%	

Wholesale revenues result from sales of electricity to utilities and power marketers made in the Company's efforts to secure reasonably priced power for its retail customers, manage risk, and administer its current long-term wholesale contracts. Such sales can vary significantly from year to year as a result of economic conditions, power and fuel prices, hydro and wind availability, and customer demand.

In 2019, an $11 million, or 7%, increase in wholesale revenues over 2018 resulted from $14 million related to a 9% increase in wholesale sales volume partially offset by $3 million from a 1% decrease in average prices received when the Company sold power into the wholesale market.

Other operating revenues increased $21 million, or 41%, in 2019 from 2018, primarily as a result of an $8 million increase attributable to the sale of excess natural gas not used to fuel the Company's generating facilities. Other contributors to the increase included $4 million related to a customer project that is offset with corresponding expense increases in Generation, transmission and distribution expense and $3 million as a result of higher revenue from joint pole usage. In addition, $6 million of incremental revenues resulted from a combination of late fees, transmission resale, storm deferrals, and a variety of smaller miscellaneous items.

Purchased power and fuel expense includes the cost of power purchased and fuel used to generate electricity to meet PGE's retail load requirements, as well as the cost of settled electric and natural gas financial contracts. In 2019, Purchased power and fuel expense increased $43 million, or 8%, from 2018, which was driven by a $61 million increase that resulted from a higher average variable power cost per MWh, offset by a $18 million decrease related to total system load.

The $61 million increase related to average variable power cost is due to an increase in cost per MWh from $25.31 in 2018 to $26.62 per MWh in 2019. The price increase was driven primarily by a 24% increase in the average variable power cost per MWh for purchased power as the Company, on average, purchased power at higher market prices. The average variable cost per MWh for PGE generating resources remained relatively flat from 2018 to 2019.

Although total system load is up 2% from 2018, the $18 million decrease due to total system load was largely due to PGE effectively dispatching its lowest-cost resources in a challenged market, resulting in a 14% increase in energy generated by PGE resource.

In 2019, energy received from Biglow Canyon and Tucannon River decreased 9% from 2018 due to less favorable wind conditions and provided 9% of the Company's retail load requirement in 2019 compared with 10% in 2018.

As a result of the less favorable hydro conditions in the region for 2019, energy received from PGE-owned hydroelectric projects in combination with mid-Columbia projects was 20% below 2018 levels and represented 13% of the Company's retail load requirement for 2019 compared with 17% for 2018.

The following table presents the actual April-to-September 2019 and 2018 runoff at particular points of major rivers relevant to PGE's hydro resources:

	Runoff as a Percent of 30-year Average	
Location	**2019 Actual**	**2018 Actual**
Columbia River at The Dalles, Oregon	94%	98%
Mid-Columbia River at Grand Coulee, Washington	87	99
Clackamas River at Estacada, Oregon	114	97
Deschutes River at Moody, Oregon	111	96

Actual NVPC, which consists of Purchased power and fuel expense net of Wholesale revenues, increased $32 million in 2019 compared with 2018. The increase attributable to changes in Purchased power and fuel expense was the result of a 5% increase in the average variable power cost per MWh and a 2% increase in total system load. This was partially offset by a 9% increase in the volume of wholesale energy deliveries, that were sold, on average, at 1% lower average price per MWh.

For 2019, actual NVPC, as calculated for regulatory purposes under the PCAM, was $5 million above the 2019 baseline NVPC. In 2018, NVPC was $3 million below the anticipated baseline. For further information regarding NVPC, see *"Power Operations"* in the Overview section of this Item 7.

Generation, transmission, and distribution expense increased $31 million, or 11%, in 2019 compared with 2018. The increase was driven by $13 million higher distribution expenses for vegetation management, wildfire mitigation and preventative maintenance, $6 million higher expenses at the Company's generation facilities, $3 million higher transmission expenses and $9 million miscellaneous expenses.

Administrative and other expense increased $19 million, or 7%, in 2019 compared with 2018, primarily due to $13 million higher overall labor and employee benefit expenses, a $10 million benefit from the Carty cash settlement that occurred in 2018 that did not recur in 2019, $5 million higher costs related to the new customer billing system (ongoing support in 2019 and 2018 deferral of costs, offset by collection in 2019), $6 million miscellaneous expenses, offset by an $11 million net year over year impact due to the change in retail customer collection experience following the implementation of the customer information system, and $4 million lower legal expenses attributable to the conclusion of the Carty litigation.

Depreciation and amortization expense in 2019 increased $27 million, or 7%, compared with 2018. The increase was primarily driven by a $19 million increase in depreciation and amortization expense resulting from capital additions, an $8 million increase related to net regulatory deferrals and amortization activity (which is offset in revenues), a $4 million increase due to the new lease standard reflecting the amortization of Finance lease right of use assets, partially offset by a $4 million increase to non-utility AROs in 2018 that did not recur in 2019.

Taxes other than income taxes expense increased $5 million, or 4%, in 2019 compared with 2018, primarily due to higher Oregon property taxes.

Interest expense increased $4 million, or 3%, in 2019 compared with 2018 as a $6 million increase was due to the new lease standard reflecting interest associated with Finance lease obligations, which are offset in Revenues, net as costs are being recovered in the AUT. In addition, a $1 million increase resulted from higher interest on net regulatory liabilities and a $1 million increase from lower AFUDC as the result of lower construction work-in-progress balances. A $4 million decrease resulted from the maturity of $300 million and the early redemption of $50 million of FMBs that were replaced with lower rate debt, reducing the Company's weighted average cost of debt.

Other income, net increased $9 million compared to 2018, with the difference due to gains of $5 million related to the non-qualified employee benefit trust assets, a $2 million curtailment gain recognized in 2019 due to changes in retiree medical plans and $2 million lower pension costs due to changes in actuarial assumptions.

Income tax expense increased $10 million, or 59%, in 2019 compared to 2018 primarily due to a decrease in PTCs and higher pre-tax income.

2018 Compared to 2017

For a comparison of the Company's results of operations for the fiscal year ended December 31, 2018 to the year ended December 31, 2017, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in the Company's Annual report on Form 10-K for the year ended December 31, 2018, filed with the SEC on February 15, 2019.

Liquidity and Capital Resources

Discussions, forward-looking statements, and projections in this section, and similar statements in other parts of this Annual Report on Form 10-K, are subject to PGE's assumptions regarding the availability and cost of capital. See *"Capital and credit market conditions could adversely affect the Company's access to capital, cost of capital, and ability to execute its strategic plan as currently envisioned."* in Item 1A.—Risk Factors, for further information.

Capital Requirements

The following table presents actual capital expenditures and debt maturities for 2019 and projected capital expenditures and future debt maturities for 2020 through 2024 (in millions, excluding AFDC):

	Years Ending December 31,					
	2019	**2020**	**2021**	**2022**	**2023**	**2024**
Ongoing capital expenditures*	$ 572	$ 675	$ 500	$ 500	$ 500	$ 500
Integrated Operations Center	27	95	80	—	—	—
Wheatridge Renewable Energy Facility	17	120	15	—	—	—
Total capital expenditures	$ 616	$ 890	$ 595	$ 500	$ 500	$ 500
Long-term debt maturities	$ 350	$ —	$ 160	$ —	$ —	$ 80

* Consists primarily of upgrades to, and replacement of, generation, transmission, and distribution infrastructure, as well as new customer connects. Includes preliminary engineering and removal costs.

During 2019, PGE funded its capital requirements through a combination of cash from operations in the amount of $546 million and proceeds from the issuance of FMBs in the amount of $470 million. Capital requirements in 2020 are expected to be $890 million. PGE plans to fund the 2020 capital requirements with cash from operations during 2020, which is expected to range from $625 million to $675 million, the issuance of debt securities of up to $400 million, and the issuance of commercial paper, as needed. The actual timing and amount of any other issuances of debt or commercial paper will be dependent upon the timing and amount of capital expenditures. For a discussion concerning PGE’s ability to fund its future capital requirements, see “*Debt and Equity Financings*” in this Item 7.

Liquidity

PGE’s access to short-term debt markets, including revolving credit from banks, helps provide necessary liquidity to support the Company’s current operating activities, including the purchase of power and fuel. Long-term capital requirements are driven largely by capital expenditures for distribution, transmission, and generation facilities to support both new and existing customers, information technology systems, and debt refinancing activities. PGE’s liquidity and capital requirements can also be significantly affected by other working capital needs, including margin deposit requirements related to wholesale market activities, which can vary depending upon the Company’s forward positions and the corresponding price curves.

The following summarizes PGE’s cash flows for the periods presented (in millions):

	Years Ended December 31,	
	2019	**2018**
Cash and cash equivalents, beginning of year	$ 119	$ 39
Net cash provided by (used in):		
Operating activities	546	630
Investing activities	(604)	(471)
Financing activities	(31)	(79)
Net change in cash and cash equivalents	(89)	80
Cash and cash equivalents, end of year	$ 30	$ 119

2019 Compared to 2018

Cash Flows from Operating Activities—Cash flows from operating activities are generally determined by the amount and timing of cash received from customers and payments made to vendors, as well as the nature and amount of non-cash items, including depreciation and amortization, deferred income taxes, and pension and other postretirement benefit costs included in net income during a given period. The $84 million decrease in cash flows from operating activities in 2019 compared to 2018 is due to:

- $68 million decrease relating to TCJA as a deferral occurred in 2018 with amortization recorded in 2019;
- $67 million decrease for Accounts payable and other accrued liabilities partially due to decreased fuel costs from lower gas prices in the fourth quarter 2019 compared to the fourth quarter 2018;
- $53 million decrease for an additional contribution to pension and other postretirement benefits; partially offset by
- $59 million decrease as a result of changes in Accounts receivable and Unbilled revenue balances;
- $27 million increase in Depreciation and amortization primarily due to higher average plant balances;
- $23 million increase in Deferred income taxes primarily due to increased contributions to pension and other postretirement benefits.

Cash provided by operations includes the recovery in customer prices of non-cash charges for depreciation and amortization. The Company estimates that such charges in 2020 will range from $415 million to $435 million. Combined with all other sources, cash provided by operations in 2020 is estimated to range from $625 million to $675 million.

Cash Flows from Investing Activities—Cash flows used in investing activities consist primarily of capital expenditures related to new construction and improvements to PGE's distribution, transmission, and generation facilities. The $133 million increase in net cash used in investing activities in 2019 compared with 2018 is primarily due to the $120 million cash inflow as a result of the Carty litigation settlement that occurred in 2018 that did not recur in 2019.

The Company plans for $890 million of capital expenditures in 2020 related to upgrades to and replacement of generation, transmission, and distribution infrastructure. PGE plans to fund the 2020 capital expenditures with cash from operations during 2020, as discussed above, as well as with the issuance of short- and long-term debt securities. For additional information, see "*Capital Requirements*" and "*Debt and Equity Financings*" in the Liquidity and Capital Resources section of this Item 7.

Cash Flows from Financing Activities—Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. During 2019, cash used in financing activities consisted primarily of the issuance of $470 million of long-term debt, less the repayment $350 million of FMBs and payment of dividends in the amount of $134 million.

2018 Compared to 2017

For a comparison of liquidity and capital resources and the Company's cash flow activities for the fiscal year ended December 31, 2018 and 2017, see Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations in the Company's Annual Report on Form 10-K for the year ended December 31, 2018, which was filed with the SEC on February 15, 2019.

Credit Ratings and Debt Covenants

PGE's secured and unsecured debt is rated investment grade by Moody's and S&P, with current credit ratings and outlook as follows:

	Moody's	**S&P**
First Mortgage Bonds	A1	A
Senior unsecured debt	A3	BBB+
Commercial paper	P-2	A-2
Outlook	Stable	Positive

In the event Moody's and/or S&P reduce their credit rating on PGE's unsecured debt below investment grade, the Company could be subject to requests by certain of its wholesale, commodity, and transmission counterparties to post additional performance assurance collateral in connection with its price risk management activities. The performance assurance collateral can be in the form of cash deposits or letters of credit, depending on the terms of the underlying agreements, and are based on the contract terms and commodity prices and can vary from period to period. Cash deposits provided as collateral are classified as Margin deposits in PGE's consolidated balance sheets, while any letters of credit issued are not reflected in the Company's consolidated balance sheets.

As of December 31, 2019, PGE had posted $31 million of collateral with these counterparties, consisting of $16 million in cash and $15 million in bank letters of credit. Based on the Company's energy portfolio, estimates of energy market prices, and the level of collateral outstanding as of December 31, 2019, the amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is $51 million and decreases to $4 million by December 31, 2020 and none by December 31, 2021. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade is $132 million and decreases to $78 million by December 31, 2020 and $68 million by December 31, 2021.

PGE's financing arrangements do not contain ratings triggers that would result in the acceleration of required interest and principal payments in the event of a ratings downgrade. However, the cost of borrowing and issuing letters of credit under the credit facilities would increase.

The Indenture securing PGE's outstanding FMBs constitutes a direct first mortgage lien on substantially all regulated utility property, other than expressly excepted property. Interest is payable semi-annually on FMBs. The issuance of FMBs requires that PGE meet earnings coverage and security provisions set forth in the Indenture of Mortgage and Deed of Trust securing the bonds. PGE estimates that on December 31, 2019, under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust, the Company could have issued up to $937 million of additional FMBs. Any issuances of FMBs would be subject to market conditions and amounts could be further limited by regulatory authorizations or by covenants and tests contained in other financing agreements. PGE also has the ability to release property from the lien of the Indenture of Mortgage and Deed of Trust under certain circumstances, including bond credits, deposits of cash, or certain sales, exchanges, or other dispositions of property.

PGE's credit facilities contain customary covenants and credit provisions, including a requirement that limits consolidated indebtedness, as defined in the credit agreements, to 65% of total capitalization (debt to total capital ratio). As of December 31, 2019, the Company's debt to total capital ratio, as calculated under the credit agreements, was 51.9%.

Debt and Equity Financings

PGE's ability to secure sufficient long-term capital at a reasonable cost is determined by its financial performance and outlook, its credit ratings, its capital expenditure requirements, alternatives available to investors, market conditions, and other factors. Management believes that the availability of revolving credit facilities, the expected ability to issue long-term debt and equity securities, and cash expected to be generated from operations provide sufficient cash flow and liquidity to meet the Company's anticipated capital and operating requirements for the foreseeable future.

Short-term Debt—Pursuant to an order issued by the FERC on January 16, 2020, PGE has authorization to issue short-term debt up to a total of $900 million through February 7, 2022.

As of December 31, 2019, PGE had a $500 million revolving credit facility scheduled to expire in November 2023. The facility allows for unlimited extension requests, provided that lenders with a pro-rata share of more than 50%, approve the extension request. The revolving credit facility supplements operating cash flows and provides a primary source of liquidity. Pursuant to the terms of the agreement, the revolving credit facility may be used as backup for commercial paper borrowings, to permit the issuance of standby letters of credit, and for general corporate purposes. PGE may borrow for one, two, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the applicable credit facility.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days, limited to the unused amount of credit under the revolving credit facility.

PGE classifies any borrowings under the revolving credit facility and outstanding commercial paper as Short-term debt in the consolidated balance sheets.

Under the revolving credit facility, as of December 31, 2019, PGE had no borrowings or commercial paper outstanding, and no letters of credit issued. As a result, as of December 31, 2019, the aggregate unused available credit capacity under the revolving credit facility was $500 million.

In addition, PGE has four letter of credit facilities under which the Company can request letters of credit for original terms not to exceed one year. These facilities provide for a total capacity of $220 million. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these facilities, letters of credit for a total of $55 million were outstanding as of December 31, 2019.

Long-term Debt—During 2019, PGE issued a total of $470 million of FMBs with $200 million issued in April at an interest rate of 4.3% maturing in 2049 and $270 million at an interest rate of 3.34% issued in two tranches. The first tranche, $110 million with a maturity in 2049, was issued in October 2019 and the second tranche, $160 million with a maturity in 2050, was issued in November 2019. A portion of the proceeds were used to repay a total of $350 million in FMBs in 2019.

As of December 31, 2019, total long-term debt outstanding, net of $11 million of unamortized debt expense, was $2,597 million, of which none is scheduled to mature in 2020.

Capital Structure—PGE's financial objectives include maintaining a common equity ratio (common equity to total consolidated capitalization, including current debt maturities) of approximately 50% over time. Achievement of this objective helps the Company maintain investment grade debt ratings and provides access to long-term capital at favorable interest rates. The Company's common equity ratio was 48.1% and 49.8% as of December 31, 2019 and 2018, respectively.

Contractual Obligations and Commercial Commitments

The following table presents PGE's contractual obligations as of December 31, 2019 (in millions):

	2020	2021	2022	2023	2024	There-after	Total
Long-term debt	$ —	$ 160	$ —	$ —	$ 80	$ 2,368	$ 2,608
Interest on long-term debt [(1)]	119	117	115	115	115	1,887	2,468
Capital and other purchase commitments	393	130	14	4	1	56	598
Purchased power and fuel:							
Electricity purchases	193	189	220	219	215	2,327	3,363
Capacity contracts	—	9	9	9	9	9	45
Public Utility Districts	16	15	13	13	12	50	119
Natural gas	59	45	40	38	42	603	827
Coal and transportation	27	27	27	27	27	27	162
Pension Plan Contributions [(2)]	—	—	9	27	30	—	66
Finance and operating lease obligations	24	24	24	22	21	281	396
Total	$ 831	$ 716	$ 471	$ 474	$ 552	$ 7,608	$ 10,652

(1) Future interest on long-term debt is calculated based on the assumption that all debt remains outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect as of December 31, 2019.

(2) Contributions beyond 2024 are not estimated due to significant uncertainty in financial market and demographic outcomes.

Other Financial Obligations

PGE has long-term power purchase agreements in place with certain public utility districts in the state of Washington.

The Company has acquired a percentage of the output of the Priest Rapids and Wanapum hydroelectric projects under an agreement that requires PGE to pay its proportionate share of the operating and debt service costs of the projects, whether or not they are operable. The agreements further provide that, should any other purchaser of output default on payments as a result of bankruptcy or insolvency, PGE would be allocated a pro-rata share of both the output and the operating and debt service costs of the defaulting purchaser.

Under an agreement for output of the Wells project, PGE receives a share of the production in return for a fixed payment. If any other purchaser of output were to default, PGE would receive a pro-rata portion of the defaulting purchaser's share of the project output and associated costs, with no limitation, regardless of the reason for the default. The share of the project output is expected to decline over time as the public utility district load grows and output is needed to serve that growth.

For additional information on these long-term power purchase agreements, see "*Public utility districts*" in Note 16, Commitments and Guarantees, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Off-Balance Sheet Arrangements

Other than the items listed below, PGE has no off-balance sheet arrangements that have, or are reasonably likely to have, a material current or future effect on its consolidated financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources:

- PGE has four letter of credit facilities that provide capacity up to a total of $220 million 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, $55 million has been issued as of December 31, 2019; and
- As a co-owner of Colstrip, PGE has provided surety bonds of $18 million as of December 31, 2019 on behalf of the operator to ensure the operation and maintenance of remedial and closure actions are carried out related to the Administrative Order on Consent Regarding Impacts Related to Wastewater Facilities Comprising the Closed-Loop System at Colstrip Steam Electric Station, Colstrip Montana (the AOC) as required by the Montana Department of Environmental Quality. It is currently anticipated that each co-owner of Colstrip will be required, at some future point, to post additional financial assurance to support further performance by the operator of closure and remediation actions under the AOC.

Critical Accounting Policies

The preparation of consolidated financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect amounts reported in the statements. The following accounting policies represent those that management believes are particularly important to the consolidated financial statements and that require the use of estimates, assumptions, and judgments to determine matters that are inherently uncertain.

Regulatory Accounting

As a rate-regulated enterprise, PGE applies regulatory accounting, which includes the recognition of regulatory assets and liabilities on the Company's consolidated balance sheets. Regulatory assets represent probable future revenue associated with certain incurred costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited or refunded to customers through the ratemaking process. Regulatory accounting is appropriate as long as prices are established or subject to approval by independent third-party regulators, prices are designed to recover the specific enterprise's cost of service, and, in view of demand for service, it is reasonable to assume that prices set at levels that will recover costs can be charged to and collected from customers. Amortization of regulatory assets and liabilities is reflected in the statement of income over the period in which they are included in customer prices.

If future recovery of regulatory assets is not probable, PGE would expense such items in the period such determination is made. Further, if PGE determines that all or a portion of its utility operations no longer meet the criteria for continued application of regulatory accounting, the Company would be required to write off those regulatory assets and liabilities related to operations that no longer meet requirements for regulatory accounting. Discontinued application of regulatory accounting would have a material impact on the Company's results of operations and financial position.

Asset Retirement Obligations

PGE recognizes AROs for legal obligations related to dismantlement and restoration costs associated with the future retirement of tangible long-lived assets. Upon initial recognition of AROs that are measurable, the probability-weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted risk-free rate, are recognized as both a liability and as an increase in the capitalized carrying amount of the related long-lived assets. Due to the long lead time involved, a market-risk premium cannot be determined for inclusion in future cash flows. In estimating the liability, management must utilize significant judgment and assumptions in determining whether a legal obligation exists to remove assets. Other estimates may be related to lease provisions, ownership agreements, licensing issues, cost estimates, inflation, and certain legal requirements. Changes that may arise over time with regard to these assumptions and determinations can change future amounts recorded for AROs.

Capitalized asset retirement costs related to electric utility plant are depreciated over the estimated life of the related asset and included in Depreciation and amortization expense in the consolidated statements of income. Accretion of the ARO liability is classified as a Depreciation and amortization expense in the consolidated statements of income. Accumulated asset retirement removal costs that do not qualify as AROs have been reclassified from accumulated depreciation to regulatory liabilities in the consolidated balance sheets.

Contingencies

PGE has various unresolved legal and regulatory matters about which there is inherent uncertainty, with the ultimate outcome contingent upon several factors. Such contingencies are evaluated using the best information available. A loss contingency is accrued, and disclosed if material, when it is probable that an asset has been impaired, or a liability incurred, and the amount of the loss can be reasonably estimated. If a range of probable loss is established, the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate. If the probable loss cannot be reasonably estimated, no accrual is recorded, but the loss contingency and the reasons to the effect that it cannot be reasonably estimated are disclosed. Material loss contingencies are disclosed when it is reasonably possible that an asset has been impaired, or a liability incurred. Established accruals reflect management's assessment of inherent risks, credit worthiness, and complexities involved in the process. There can be no assurance as to the ultimate outcome of any particular contingency.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

PGE is exposed to various forms of market risk, consisting primarily of fluctuations in commodity prices, foreign currency exchange rates, and interest rates, as well as credit risk. Any variations in the Company's market risk or credit risk may affect its future financial position, results of operations, or cash flows, as discussed below.

Risk Management Committee

PGE has a Risk Management Committee (RMC), which is responsible for providing oversight of the adequacy and effectiveness of corporate policies, guidelines, and procedures for market and credit risk management related to the Company's energy portfolio management activities. The RMC consists of officers and Company representatives with responsibility for risk management, finance and accounting, information technology, utility operations, legal, and rates and regulatory affairs. The RMC reviews and approves adoption of policies and procedures, and monitors compliance with policies, procedures, and limits on a regular basis through reports and meetings. The RMC also reviews and recommends risk limits that are subject to approval by PGE's Board of Directors.

Commodity Price Risk

PGE is exposed to commodity price risk as its primary business is to provide electricity to its retail customers. The Company engages in price risk management activities to manage exposure to volatility in net power costs for its retail customers. The Company uses power purchase contracts to supplement its own generation and to respond to fluctuations in the demand for electricity and variability in generating plant operations. The Company also enters into contracts for the purchase of fuel for the Company's natural gas- and coal-fired generating plants. These contracts for the purchase of power and fuel expose the Company to market risk. The Company uses instruments such as: i) forward contracts, which may involve physical delivery of an energy commodity; ii) financial swap and futures agreements, which may require payments to, or receipt of payments from, counterparties based on the differential between a fixed and variable price for the commodity; and iii) option contracts to mitigate risk that arises from market fluctuations of commodity prices. PGE does not engage in trading activities for non-retail purposes.

The following table presents energy commodity derivative fair values as a net liability as of December 31, 2019 that are expected to settle in each respective year (in millions):

	2020	2021	2022	2023	2024	Thereafter	Total
Commodity contracts:							
Electricity	$ 5	$ 1	$ 7	$ 7	$ 7	$ 76	$ 103
Natural gas	(7)	(2)	(1)	—	—	—	(10)
	$ (2)	$ (1)	$ 6	$ 7	$ 7	$ 76	$ 93

PGE reports energy commodity derivative fair values as a net asset or liability, which combines purchases and sales expected to settle in the years noted above. Energy commodity fair values exposed to commodity price risk are primarily related to purchase contracts, which are slightly offset by sales.

PGE's energy portfolio activities are subject to regulation, with related costs included in retail prices approved by the OPUC. The timing differences between the recognition of gains and losses on certain derivative instruments and their realization and subsequent recovery in prices are deferred as regulatory assets and regulatory liabilities to reflect the effects of regulation, significantly mitigating commodity price risk for the Company. As contracts are settled, these deferrals reverse and are recognized as Purchased power and fuel in the statements of income and included in the PCAM. PGE remains subject to cash flow risk in the form of collateral requirements based on the value of open positions and regulatory risk if recovery is disallowed by the OPUC. PGE attempts to mitigate both types of risks through prudent energy procurement practices.

Foreign Currency Exchange Rate Risk

PGE is exposed to foreign currency risk associated with natural gas forward and swap contracts denominated in Canadian dollars. Foreign currency risk is the risk of changes in value of pending financial obligations in foreign currencies that could occur prior to the settlement of the obligation due to a change in the value of that foreign currency in relation to the U.S. dollar. PGE mitigates its exposure to fluctuations in the Canadian exchange rate with an appropriate hedging strategy.

As of December 31, 2019, a 10% change in the value of the Canadian dollar would result in an immaterial change in exposure for transactions that will settle over the next twelve months.

Interest Rate Risk

To meet short-term cash requirements, PGE has the ability to issue commercial paper for terms of up to 270 days and has a revolving credit facility that permits same day borrowings. Although any borrowings under the commercial paper program or the revolving credit facility carry a fixed rate during their respective terms, the short-term nature of such borrowings subjects the Company to fluctuations in interest rates that result from changes in market conditions. As of December 31, 2019, PGE had no borrowings outstanding under its revolving credit facility and no commercial paper or other short-term debt outstanding.

In 2018 PGE entered into two forward starting interest rate swap lock agreements to hedge a portion of its interest rate risk associated with anticipated issuances of fixed-rate, long-term debt securities. These derivatives were designated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance.

As of December 31, 2018, the fair value of the interest rate swaps was a $4 million liability, which was recorded in Liabilities from price risk management activities - current on the Company's consolidated balance sheets. The swaps settled at a $5 million loss in January 2019, which was recorded in Regulatory assets - noncurrent on the consolidated balance sheets, and are subsequently being amortized as a component of interest expense over the life of the associated debt. Such amounts are also included as a component of cost of debt for ratemaking purposes. As of December 31, 2019, the Company had no outstanding interest rate swaps.

As of December 31, 2019, the total fair value and carrying amounts, excluding unamortized debt expense, by maturity date of PGE's long-term debt are as follows (in millions):

	Total Fair Value	Carrying Amounts by Maturity Date					
		Total	2020	2021	2022	2023	There-after
First Mortgage Bonds	$ 2,938	$ 2,510	$ —	$ 160	$ —	$ —	$ 2,350
Pollution Control Revenue Bonds	101	98	—	—	—	—	98
Total	$ 3,039	$ 2,608	$ —	$ 160	$ —	$ —	$ 2,448

As of December 31, 2019, PGE had no long-term debt instruments subject to interest rate risk exposures.

Credit Risk

PGE is exposed to credit risk in its commodity price risk management activities related to potential nonperformance by counterparties. The Company manages the risk of counterparty default according to its credit policies by performing financial credit reviews, setting limits and monitoring exposures, and requiring collateral (in the form of cash, letters of credit, and guarantees) when needed. PGE also uses standardized enabling agreements and, in certain cases, master netting agreements, which allow for the netting of positive and negative exposures under multiple agreements with counterparties. Despite such mitigation efforts, defaults by counterparties may periodically occur. Based upon periodic review and evaluation, allowances are recorded as needed to reflect credit risk related to wholesale accounts receivable.

The large number and diversified base of residential, commercial, and industrial customers, combined with the Company's ability to discontinue service, contribute to reduce credit risk with respect to trade accounts receivable from retail sales. Estimated provisions for uncollectible accounts receivable related to retail sales are provided for such risk.

As of December 31, 2019, PGE's credit risk exposure is $47 million for commodity activities, of which $36 million is with externally-rated investment grade counterparties. The underlying transactions that make up the exposure will mature during 2023. The exposure is included in accounts receivable and price risk management assets, offset by related accounts payable and price risk management liabilities.

Investment grade counterparties include those with a minimum credit rating on senior unsecured debt of Baa3 (as assigned by Moody's) or BBB- (as assigned by S&P), and also those counterparties whose obligations are guaranteed or secured by an investment grade entity. The credit exposure includes activity for electricity and natural gas forward, swap, and option contracts. Posted collateral may be in the form of cash or letters of credit, and may represent prepayment or credit exposure assurance.

Omitted from the market risk exposures discussed above are long-term power purchase contracts with certain public utility districts in the state of Washington. These contracts currently provide PGE with a percentage share of hydro facility output in exchange for an equivalent percentage share of operating and debt service costs. These contracts expire at varying dates through 2052. For additional information, see "*Public utility districts*" in Note 16, Commitments and Guarantees, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data." Management believes that circumstances that could result in the nonperformance by these counterparties are remote.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The following financial statements and report are included in Item 8:

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Portland General Electric Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Portland General Electric Company and subsidiaries (the "Company") as of December 31, 2019 and 2018, the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2019, and the related notes (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

Basis for Opinions

The Company’s management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company’s internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Contingencies - EPA Investigation of Portland Harbor- Refer to Note 19 to the financial statements

Critical Audit Matter Description

The Company is an identified Potentially Responsible Party (PRP) related to the United States Environmental Protection Agency's (EPA's) investigation of Portland Harbor, for which total undiscounted clean-up costs are estimated to be $1.7 billion based on the selected remediation plan in the Record of Decision issued by the EPA in January 2017. In accounting for environmental obligations, management should record a liability associated with the Company's environmental obligations when such a loss becomes both probable and reasonably estimable, the determination of which requires significant judgment by management. Management has concluded that a loss is probable, but the amount of such loss cannot be reasonably estimated, and therefore no liability has been recorded as of December 31, 2019.

Given the level of management judgment involved in determining whether sufficient information exists to reasonably estimate the amount, or range, of the Company's potential liability, auditing management's determination involved a high degree of auditor judgment.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's assessment of the ability to reasonably estimate the Company's potential liability related to the Portland Harbor site included the following, among others:

- We evaluated the design, and tested the operating effectiveness, of controls over management's evaluation as to whether a loss related to the Portland Harbor site is probable and is reasonably estimable.

- We read management's analysis of the EPA investigation of Portland Harbor and evaluated whether management had appropriately applied the relevant accounting guidance based on the facts identified in the analysis.

- With the assistance of our environmental specialists, we performed a public domain search specifically tailored to identify relevant information from the EPA, United States Department of Justice, local news reports and other relevant sources to identify items that may represent triggering events that could potentially impact management's assertion that any loss associated with Portland Harbor is not reasonably estimable. We compared this information to the information included in management's analysis and evaluated whether management had omitted any relevant evidence, including evidence that may be contradictory to management's assertion.

- We compared the Company's disclosures associated with the matter to those of other PRP's.

Regulatory Accounting - Refer to Notes 2 and 7 to the financial statements

Critical Audit Matter Description

The Company is subject to rate regulation by the Public Utility Commission of Oregon (the OPUC), which has jurisdiction with respect to the rates for retail electricity in the state of Oregon. Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as property, plant, and equipment; regulatory assets and liabilities; operating revenues; operation and maintenance expense; income taxes; and depreciation expense.

The Company's rates for retail customers are determined and approved in regulatory proceedings based on an analysis of the Company's costs. The OPUC has the authority to disallow the recovery of any costs that it considers imprudently incurred. Although the OPUC is required to establish customer prices that are fair, just and reasonable, it has significant discretion in the interpretation of this standard.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the degree of subjectivity involved in assessing the impact of future regulatory proceedings on the financial statements. Management judgments include assessing the likelihood of recovery in future rates of incurred costs and refunds to customers. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the OPUC, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the OPUC included the following, among others:

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs deferred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management's controls over regulatory developments that may affect the likelihood of recovering costs in future rates or of a refund or future reduction in rates.

- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.

- We read relevant regulatory orders issued by the OPUC for the Company, regulatory statutes, and other publicly available information to assess the likelihood of recovery in future rates or of a refund or future reduction in rates based on precedence of the OPUC's treatment of similar costs under similar circumstances.

- For selected regulatory assets and liabilities, we evaluated whether management had determined such amounts in accordance with the regulatory orders.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 13, 2020

We have served as the Company's auditor since 2004.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(Dollars in millions, except per share amounts)

	Years Ended December 31,		
	2019	2018	2017
Revenues:			
Revenues, net	$ 2,121	$ 1,988	$ 2,009
Alternative revenue programs, net of amortization	2	3	—
Total Revenues	2,123	1,991	2,009
Operating expenses:			
Purchased power and fuel	614	571	592
Generation, transmission and distribution	323	292	309
Administrative and other	290	271	260
Depreciation and amortization	409	382	345
Taxes other than income taxes	134	129	123
Total operating expenses	1,770	1,645	1,629
Income from operations	353	346	380
Interest expense, net	128	124	120
Other income:			
Allowance for equity funds used during construction	10	11	12
Miscellaneous income (expense), net	6	(4)	1
Other income, net	16	7	13
Income before income taxes	241	229	273
Income tax expense	27	17	86
Net income	$ 214	$ 212	$ 187
Weighted-average shares outstanding (in thousands):			
Basic	89,353	89,215	89,056
Diluted	89,559	89,347	89,176
Earnings per share:			
Basic	$ 2.39	$ 2.38	$ 2.10
Diluted	$ 2.39	$ 2.37	$ 2.10

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Years Ended December 31,		
	2019	2018	2017
Net income	$ 214	$ 212	$ 187
Other comprehensive income (loss)—Change in compensation retirement benefits liability and amortization, net of taxes of an immaterial amount in 2019, 2018, and 2017	(1)	1	(1)
Comprehensive income	$ 213	$ 213	$ 186

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In millions)

	As of December 31,	
	2019	**2018**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 30	$ 119
Accounts receivable, net	167	193
Unbilled revenues	86	96
Inventories, at average cost:		
Materials and supplies	56	53
Fuel	40	31
Regulatory assets—current	17	61
Other current assets	104	90
Total current assets	500	643
Electric utility plant:		
In service	10,928	10,344
Accumulated depreciation and amortization	(4,095)	(3,803)
In service, net	6,833	6,541
Construction work-in-progress	328	346
Electric utility plant, net	7,161	6,887
Regulatory assets—noncurrent	483	401
Nuclear decommissioning trust	46	42
Non-qualified benefit plan trust	38	36
Other noncurrent assets	166	101
Total assets	$ 8,394	$ 8,110

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS, continued
(In millions, except share amounts)

	As of December 31,	
	2019	**2018**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 165	$ 168
Liabilities from price risk management activities—current	23	55
Current portion of long-term debt	—	300
Current portion of finance lease obligations	16	—
Accrued expenses and other current liabilities	315	268
Total current liabilities	519	791
Long-term debt, net of current portion	2,597	2,178
Regulatory liabilities—noncurrent	1,377	1,355
Deferred income taxes	378	369
Unfunded status of pension and postretirement plans	247	307
Liabilities from price risk management activities—noncurrent	108	101
Asset retirement obligations	263	197
Non-qualified benefit plan liabilities	103	103
Finance lease obligations, net of current portion	135	—
Other noncurrent liabilities	76	203
Total liabilities	5,803	5,604
Commitments and contingencies (see notes)		
Shareholders' equity:		
Preferred stock, no par value, 30,000,000 shares authorized; none issued and outstanding	—	—
Common stock, no par value, 160,000,000 shares authorized; 89,387,124 and 89,267,959 shares issued and outstanding as of December 31, 2019 and 2018, respectively	1,220	1,212
Accumulated other comprehensive loss	(10)	(7)
Retained earnings	1,381	1,301
Total shareholders' equity	2,591	2,506
Total liabilities and shareholders' equity	$ 8,394	$ 8,110

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(In millions, except share and per share amounts)

	Common Stock		Accumulated Other Comprehensive Loss	Retained Earnings	Total
	Shares	Amount			
Balance as of December 31, 2016	88,946,704	$ 1,201	$ (7)	$ 1,150	$ 2,344
Shares issued pursuant to equity-based plans	167,561	2	—	—	2
Stock-based compensation	—	4	—	—	4
Dividends declared ($1.34 per share)	—	—	—	(120)	(120)
Net income	—	—	—	187	187
Other comprehensive (loss)	—	—	(1)	—	(1)
Balance as of December 31, 2017	89,114,265	1,207	(8)	1,217	2,416
Shares issued pursuant to equity-based plans	153,694	1	—	—	1
Stock-based compensation	—	4	—	—	4
Dividends declared ($1.4275 per share)	—	—	—	(128)	(128)
Net income	—	—	—	212	212
Other comprehensive income	—	—	1	—	1
Balance as of December 31, 2018	89,267,959	1,212	(7)	1,301	2,506
Shares issued pursuant to equity-based plans	119,165	1	—	—	1
Stock-based compensation	—	7	—	—	7
Dividends declared ($1.5175 per share)	—	—	—	(136)	(136)
Net income	—	—	—	214	214
Reclassification of stranded tax effects due to Tax Reform	—	—	(2)	2	—
Other comprehensive (loss)	—	—	(1)	—	(1)
Balance as of December 31, 2019	89,387,124	$ 1,220	$ (10)	$ 1,381	$ 2,591

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2019	**2018**	**2017**
Cash flows from operating activities:			
Net income	$ 214	$ 212	$ 187
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	409	382	345
Deferred income taxes	6	(17)	70
Allowance for equity funds used during construction	(10)	(11)	(12)
Pension and other postretirement benefits	21	30	24
Decoupling mechanism deferrals, net of amortization	(2)	(2)	(22)
(Amortization) Deferral of net benefits due to Tax Reform	(23)	45	—
Stock-based compensation	9	5	7
Other non-cash income and expenses, net	34	16	24
Changes in working capital:			
Decrease (increase) in receivables and unbilled revenues	30	(29)	(3)
(Increase) in margin deposits	—	(5)	(3)
(Decrease) increase in payables and accrued liabilities	(16)	51	5
Other working capital items, net	(12)	(11)	1
Contribution to non-qualified employee benefit trust	(11)	(11)	(8)
Contribution to pension and other postretirement plans	(65)	(12)	(5)
Other, net	(38)	(13)	(13)
Net cash provided by operating activities	546	630	597
Cash flows from investing activities:			
Capital expenditures	(606)	(595)	(514)
Purchases of nuclear decommissioning trust securities	(8)	(12)	(18)
Sales of nuclear decommissioning trust securities	13	15	21
Proceeds from Carty Settlement	—	120	—
Other, net	(3)	1	(3)
Net cash used in investing activities	(604)	(471)	(514)

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS, continued
(In millions)

	Years Ended December 31,		
	2019	**2018**	**2017**
Cash flows from financing activities:			
Proceeds from issuance of long-term debt	$ 470	$ 75	$ 225
Payments on long-term debt	(350)	(24)	(150)
Debt extinguishment costs	(9)	—	—
Dividends paid	(134)	(125)	(118)
Other	(8)	(5)	(7)
Net cash used in financing activities	(31)	(79)	(50)
(Decrease) increase in cash and cash equivalents	(89)	80	33
Cash and cash equivalents, beginning of year	119	39	6
Cash and cash equivalents, end of year	$ 30	$ 119	$ 39
Supplemental disclosures of cash flow information:			
Cash paid for:			
Interest, net of amounts capitalized	$ 116	$ 117	$ 110
Income taxes	33	25	18
Non-cash investing and financing activities:			
Accrued capital additions	76	61	53
Accrued dividends payable	36	34	31
Assets obtained under leasing arrangements	210	24	87

See accompanying notes to consolidated financial statements.

NOTE 1: BASIS OF PRESENTATION

Nature of Operations

Portland General Electric Company (PGE or the Company) is a single, vertically-integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon. The Company also participates in the wholesale market by purchasing and selling electricity and natural gas in an effort to obtain reasonably-priced power for its retail customers. PGE operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. The Company's corporate headquarters is located in Portland, Oregon and its approximately 4,000 square mile, state-approved service area is located entirely within the state of Oregon. PGE's allocated service area includes 51 incorporated cities. As of December 31, 2019, PGE served approximately 895,000 thousand retail customers with a service area population of approximately 1.9 million.

As of December 31, 2019, PGE had 2,949 employees, with 775 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 719 and 56 employees and expire March 2022 and August 2022, respectively.

PGE is subject to the jurisdiction of the Public Utility Commission of Oregon (OPUC) with respect to retail prices, utility services, accounting policies and practices, issuances of securities, and certain other matters. Retail prices are based on the Company's cost to serve customers, including an opportunity to earn a reasonable rate of return, as determined by the OPUC. The Company is also subject to regulation by the Federal Energy Regulatory Commission (FERC) in matters related to wholesale energy transactions, transmission services, reliability standards, natural gas pipelines, hydroelectric project licensing, accounting policies and practices, short-term debt issuances, and certain other matters.

Consolidation Principles

The consolidated financial statements include the accounts of PGE and its wholly-owned subsidiaries. The Company's ownership share of direct expenses and costs related to jointly-owned generating plants are also included in its consolidated financial statements. For further information on PGE's jointly-owned plant, see Note 18, Jointly-Owned Plant. Intercompany balances and transactions have been eliminated.

Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosures of gain or loss contingencies, as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ materially from those estimates.

Reclassifications

To conform with the 2019 presentation, PGE has condensed the functional asset class presentation for Electric utility plant on the consolidated balance sheets for 2018, which is now presented within Note 4, Balance Sheet Components. PGE also reclassified Stock-based compensation expense of $5 million in 2018 and $7 million in 2017 from Other non-cash income and expense, net to its own line item within the operations section of the consolidated statements of cash flows.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash and Cash Equivalents

Highly liquid investments with maturities of three months or less at the date of acquisition are classified as cash equivalents, of which PGE had $26 million as of December 31, 2019 and $112 million as of December 31, 2018 included within Cash and cash equivalents in the consolidated balance sheets.

Accounts Receivable

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

Provisions for uncollectible accounts receivable related to retail sales are charged to Administrative and other expense and are recorded in the same period as the related revenues, with an offsetting credit to the allowance for uncollectible accounts. Such estimates are based on management's assessment of the probability of collection, aging of accounts receivable, bad debt write-offs, actual customer billings, and other factors.

Provisions for uncollectible accounts receivable related to wholesale sales are charged to Purchased power and fuel expense and are recorded periodically based on a review of counterparty non-performance risk and contractual right of offset when applicable. There have been no material write-offs of accounts receivable related to wholesale sales in 2019, 2018, or 2017.

Price Risk Management

PGE engages in price risk management activities, utilizing financial instruments such as forward, future, swap, and option contracts for electricity, natural gas, and foreign currency. These instruments are measured at fair value and recorded on the consolidated balance sheets as assets or liabilities from price risk management activities. Changes in fair value are recognized in the consolidated statements of income, offset by the effects of regulatory accounting. Certain electricity forward contracts that were entered into in anticipation of serving the Company's regulated retail load may meet the requirements for treatment under the normal purchases and normal sales scope exception. Such contracts are not recorded at fair value and are recognized under accrual accounting.

Price risk management activities are utilized as economic hedges to protect against variability in expected future cash flows due to associated price risk and to manage exposure to volatility in net variable power costs (NVPC).

In accordance with ratemaking and cost recovery processes authorized by the OPUC, PGE recognizes a regulatory asset or liability to defer unrealized losses or gains, respectively, on derivative instruments until settlement. At the time of settlement, the Company recognizes a realized gain or loss on the derivative instrument.

Physically settled electricity and natural gas sale and purchase transactions are recorded in Revenues, net and Purchased power and fuel expense, respectively, upon settlement, while transactions that are not physically settled (financial transactions) are recorded on a net basis in Purchased power and fuel expense upon financial settlement.

Pursuant to transactions entered into in connection with PGE's price risk management activities, the Company may be required to provide collateral to certain counterparties. The collateral requirements are based on the contract terms and commodity prices and can vary period to period. Cash deposits provided as collateral are included within Other current assets in the consolidated balance sheets and were $16 million as of December 31, 2019 and 2018. Letters of credit provided as collateral are not recorded on the Company's consolidated balance sheets and were $15 million and $48 million as of December 31, 2019 and 2018, respectively.

Inventories

PGE's inventories, which are recorded at average cost, consist primarily of materials and supplies for use in operations, maintenance, and capital activities, as well as fuel, which includes natural gas, coal, and oil for use in the Company's generating plants. Periodically, the Company assesses inventory for purposes of determining that inventories are recorded at the lower of average cost or net realizable value.

Electric Utility Plant

Capitalization Policy

Electric utility plant is capitalized at original cost, which includes direct labor, materials and supplies, and contractor costs, as well as indirect costs such as engineering, supervision, employee benefits, and an allowance for funds used during construction (AFDC). Plant replacements are capitalized, with minor items charged to expense as incurred. Periodic major maintenance inspections and overhauls at PGE's generating plants are charged to expense as incurred, subject to regulatory accounting as applicable. Costs to purchase or develop software applications for internal use only are capitalized and amortized over the estimated useful life of the software. Costs of obtaining FERC licenses for the Company's hydroelectric projects are capitalized and amortized over the related license period.

During the period of construction, costs expected to be included in the final value of the constructed asset, and depreciated once the asset is complete and placed in service, are classified as Construction work-in-progress (CWIP) in Electric utility plant on the consolidated balance sheets. If the project becomes probable of being abandoned, such costs are expensed in the period such determination is made. If any costs are expensed, PGE may seek recovery of such costs in customer prices, although there can be no guarantee such recovery would be granted. Costs disallowed for recovery in customer prices, if any, are charged to expense at the time such disallowance becomes probable.

PGE records AFDC, which is intended to represent the Company's cost of funds used for construction purposes, based on the rate granted in the latest general rate case for equity funds and the cost of actual borrowings for debt funds. AFDC is capitalized as part of the cost of plant and credited to the consolidated statements of income. The average rate used by PGE was 7.1% in 2019, and 7.3% in 2018 and 2017. AFDC from borrowed funds was $5 million in 2019 and $6 million in 2018 and 2017 and is reflected as a reduction to Interest expense, net. AFDC from equity funds, included in Other income, net, was $10 million in 2019, $11 million in 2018, and $12 million in 2017.

On December 31, 2019, the FERC approved PGE's request to reclassify the functional asset classification of certain 115kV facilities from Distribution to Transmission to align classification with the primary function of these assets. As a result, on December 31, 2019, PGE reclassified $223 million of Electric utility plant in service assets from Distribution to Transmission. Accumulated depreciation and amortization related to these facilities is $113 million as of December 31, 2019. Additions to such assets, or construction of similar types of assets, will be classified as Transmission going forward.

Depreciation and Amortization

Depreciation is computed using the straight-line method, based upon original cost, and includes an estimate for cost of removal and expected salvage. Depreciation expense as a percent of the related average depreciable plant in service was 3.6% in 2019, 2018 and 2017. A component of depreciation expense includes estimated asset retirement removal costs allowed in customer prices.

Periodic studies are conducted to update depreciation parameters (i.e. retirement dispersion patterns, average service lives, and net salvage rates), including estimates of asset retirement obligations (AROs) and asset retirement removal costs. The studies are conducted at a minimum of every five years and are filed with the OPUC for approval and inclusion in a future rate proceeding. The most recent depreciation study was completed based on 2015 data, with an order received from the OPUC in September 2017 authorizing new depreciation rates effective January 1, 2018. This study was incorporated into the Company's 2018 general rate case filed with the OPUC in 2017.

Thermal generation plants are depreciated using a life-span methodology which ensures that plant investment is recovered by the estimated retirement dates, which range from 2020 to 2059. Depreciation is provided on PGE's other classes of plant in service over their estimated average service lives, which are as follows (in years):

Generation, excluding thermal:	
Hydro	98
Wind	30
Transmission	59
Distribution	46
General	12

When property is retired and removed from service, the original cost of the depreciable property units, net of any related salvage value, is charged to accumulated depreciation. Cost of removal expenditures are recorded against AROs or to accumulated asset retirement removal costs, if applicable, and included in Regulatory liabilities.

Intangible plant consists primarily of computer software development costs, which are amortized over either five or ten years, and hydro licensing costs, which are amortized over the applicable license term, which range from 30 to 50 years. Accumulated amortization was $366 million and $302 million as of December 31, 2019 and 2018, respectively, with amortization expense of $64 million in 2019, $59 million in 2018, and $46 million in 2017. Future estimated amortization expense as of December 31, 2019 is as follows: $60 million in 2020; $52 million in 2021; $46 million in 2022; $37 million in 2023; and $32 million in 2024.

Marketable Securities

Nuclear decommissioning trust

Reflects assets held in trust to cover general decommissioning costs and operation of the Independent Spent Fuel Storage Installation (ISFSI) at the decommissioned Trojan nuclear power plant (Trojan), which was closed in 1993. The Nuclear decommissioning trust (NDT) includes amounts collected from customers, less qualified expenditures, plus any realized and unrealized gains and losses on the investments held therein.

Non-qualified benefit plan trust

Reflects assets held in trust to cover the obligations of PGE's non-qualified benefit plans (NQBP) and represents contributions made by the Company, less qualified expenditures, plus any realized and unrealized gains and losses on the investments held therein.

All of PGE's investments in marketable securities included in NDT and NQBP trust on the consolidated balance sheets, are classified as equity or trading debt securities. These securities are classified as noncurrent because they are not available for use in operations. Such securities are stated at fair value based on quoted market prices. Realized and unrealized gains and losses on the NQBP trust assets are included in Other income, net. Realized and unrealized gains and losses on the NDT fund assets are recorded as regulatory liabilities or assets, respectively, for future ratemaking treatment. The cost of securities sold is based on the average cost method.

Regulatory Accounting

Regulatory Assets and Liabilities

As a rate-regulated enterprise, PGE applies regulatory accounting, which results in the creation of regulatory assets and regulatory liabilities. Regulatory assets represent: i) probable future revenue associated with certain actual or estimated costs that are expected to be recovered from customers through the ratemaking process; or ii) probable future collections from customers resulting from revenue accrued for completed alternative revenue programs, provided certain criteria are met. Regulatory liabilities represent probable future reductions in revenue associated with amounts that are expected to be credited to customers through the ratemaking process. Regulatory accounting is appropriate as long as: i) prices are established by, or subject to, approval by independent third-party regulators; ii) prices are designed to recover the specific enterprise's cost of service; and iii) in view of demand for service, it is reasonable to assume that prices set at levels that will recover costs can be charged to and collected from customers. Once the regulatory asset or liability is reflected in prices, the respective regulatory asset or liability is amortized to the appropriate line item in the consolidated statement of income over the period in which it is included in prices.

Circumstances that could result in the discontinuance of regulatory accounting include: i) increased competition that restricts PGE's ability to establish prices to recover specific costs; and ii) a significant change in the manner in which prices are set by regulators from cost-based regulation to another form of regulation. The Company periodically reviews the criteria of regulatory accounting to ensure that its continued application is appropriate. Based on a current evaluation of the various factors and conditions, management believes that recovery of PGE's regulatory assets is probable.

For additional information concerning the Company's regulatory assets and liabilities, see Note 7, Regulatory Assets and Liabilities.

Power Cost Adjustment Mechanism

PGE is subject to a power cost adjustment mechanism (PCAM), as approved by the OPUC. Pursuant to the PCAM, future customer prices can be adjusted to reflect a portion of the difference between: i) NVPC forecast each year and included in customer prices (baseline NVPC); and ii) actual NVPC for the year. NVPC consists of the cost of power purchased and fuel used to generate electricity to meet PGE's retail load requirements, as well as the cost of settled electric and natural gas financial contracts, all of which is classified as Purchased power and fuel in the Company's consolidated statements of income, and is net of wholesale sales, which are classified as Revenues, net in the consolidated statements of income.

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

To the extent actual NVPC, subject to certain adjustments, is outside the deadband range, the PCAM provides for 90% of the excess variance to be collected from, or refunded to, customers. Pursuant to a regulated earnings test, a refund will occur only to the extent that it results in PGE's actual regulated return on equity (ROE) for the given year being no less than 1% above the Company's latest authorized ROE, while a collection will occur only to the extent that it results in PGE's actual regulated ROE for that year being no greater than 1% below the Company's authorized ROE. PGE's authorized ROE was 9.5% for 2019 and 2018, and 9.6% for 2017.

Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Revenues, net in PGE's consolidated statements of income, while any estimated collection from customers is recorded as a reduction in Purchased power and fuel expense. A final determination of any customer refund or collection is made in the following year by the OPUC through a public filing and review. The PCAM has resulted in no collection from, or refund to, customers since 2011.

Asset Retirement Obligations

Legal obligations related to the future retirement of tangible long-lived assets are classified as AROs on PGE's consolidated balance sheets. An ARO is recognized in the period in which the legal obligation is incurred, and when the fair value of the liability can be reasonably estimated. Due to the long lead time involved until decommissioning activities occur, the Company uses present value techniques because quoted market prices and market-risk premiums are not available. The present value of estimated future decommissioning costs is capitalized and included in Electric utility plant, net on the consolidated balance sheets with a corresponding offset to ARO. For revisions to AROs in which the related asset is no longer in service, the corresponding offset is recorded as a Regulatory asset on the consolidated balance sheets, except for those AROs related to non-utility assets which is charged to Depreciation and amortization on the consolidated statements of income. Such estimates are revised periodically, with actual settlements charged to the ARO as incurred.

The estimated capitalized costs of AROs are depreciated over the estimated life of the related asset, with such depreciation included in Depreciation and amortization in the consolidated statements of income. Changes in the ARO resulting from the passage of time (accretion) is based on the original discount rate and recognized as an increase in the carrying amount of the liability and as a charge to accretion expense, which is included in Depreciation and amortization expense in the Company's consolidated statements of income.

For additional information concerning the Company's AROs, see Note 8, Asset Retirement Obligations.

The difference between the timing of the recognition of ARO depreciation and accretion expenses and the amount included in customers' prices is recorded as a regulatory asset or liability in the Company's consolidated balance sheets. As of December 31, 2019, PGE had a net regulatory liability related to Utility plant AROs in the amount of $54 million and a net regulatory asset related to Trojan decommissioning ARO activities of $91 million. As of December 31, 2018, PGE had a net regulatory liability related to Utility plant AROs in the amount of $53 million and a net regulatory asset related to Trojan decommissioning ARO activities of $25 million. For additional information concerning the Company's regulatory assets and liabilities related to AROs, see Note 7, Regulatory Assets and Liabilities.

Contingencies

Contingencies are evaluated using the best information available at the time the consolidated financial statements are prepared. Legal costs incurred in connection with loss contingencies are expensed as incurred. Loss contingencies, including environmental contingencies, are accrued, and disclosed if material, when it is probable that an asset has been impaired, or a liability incurred, as of the financial statement date and the amount of the loss can be reasonably estimated. If a reasonable estimate of probable loss cannot be determined, a range of loss may be established, in which case the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate.

A loss contingency will also be disclosed when it is reasonably possible that an asset has been impaired, or a liability, incurred if the estimate or range of potential loss is material. If a probable or reasonably possible loss cannot be determined, then the Company: i) discloses an estimate of such loss or the range of such loss, if the Company is able to determine such an estimate; or ii) discloses that an estimate cannot be made and the reasons why the estimate cannot be made.

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

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

For additional information concerning the Company's contingencies, see Note 19, Contingencies.

Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss (AOCL) presented on the consolidated balance sheets is comprised of the difference between the non-qualified benefit plans' obligations recognized in net income and the unfunded position.

Revenue Recognition

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

Franchise taxes, which are collected from customers and remitted to taxing authorities, are recorded on a gross basis in PGE's consolidated statements of income. Amounts collected from customers are included in Revenues, net and amounts due to taxing authorities are included in Taxes other than income taxes and totaled $45 million in 2019 and 2018, and $43 million in 2017.

Retail revenue is billed based on monthly meter readings taken at various cycle dates throughout the month. At the end of each month, PGE estimates the revenue earned from energy deliveries that remained unbilled to customers. The estimate, which is classified as Unbilled revenues in the Company's consolidated balance sheets, is calculated based on actual net retail system load each month, the number of days from the last meter read date through the last day of the month, and current customer prices.

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

Alternative Revenue Programs

Revenues related to PGE's decoupling mechanism is considered earned under alternative revenue programs, as this amount represent a contract with the regulator and not with customers. Such revenues are presented separately from revenues from contracts with customers and classified as Alternative revenue programs, net of amortization on the consolidated statements of income. The activity within this line item is comprised of current period deferral adjustments, which can either be a collection from or a refund to customers, and is net of any related amortization. When amounts related to alternative revenue programs are ultimately included in prices and customer bills, the amounts are included within Revenues, net, with an equal and offsetting amount of amortization recorded on the Alternative revenue programs, net of amortization line item.

Stock-Based Compensation

The measurement and recognition of compensation expense for all share-based payment awards, including restricted stock units, is based on the estimated fair value of the awards. The fair value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite vesting period. PGE attributes the value of stock-based compensation to expense on a straight-line basis. For additional information concerning the Company's Stock-Based Compensation, see Note 14, Stock-Based Compensation Expense.

Income Taxes

Income taxes are accounted for under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between financial statement carrying amounts and tax bases of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in current and future periods that includes the enactment date. Any valuation allowance would be established to reduce deferred tax assets to the "more likely than not" amount expected to be realized in future tax returns.

Because PGE is a rate-regulated enterprise, changes in certain deferred tax assets and liabilities are required to be passed on to customers through future prices and are charged or credited directly to a regulatory asset or regulatory liability. Such amounts were recognized as net regulatory liabilities of $260 million and $267 million as of December 31, 2019 and 2018, respectively, and will primarily be amortized using the average rate assumption method to account for the refund to customers as the temporary differences reverse.

Unrecognized tax benefits represent management's expected treatment of a tax position taken in a filed tax return or planned to be taken in a future tax return, that has not been reflected in measuring income tax expense for financial reporting purposes. Until such positions are no longer considered uncertain, PGE would not recognize the tax benefits resulting from such positions and would report the tax effect as a liability in the Company's consolidated balance sheets.

PGE records any interest and penalties related to income tax deficiencies in Interest expense and Other income, net, respectively, in the consolidated statements of income.

Recent Accounting Pronouncements

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

In August 2018, the FASB issued ASU 2018-15 *Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract*, to provide guidance on implementation costs incurred in a cloud computing arrangement that is a service contract. ASU 2018-15 aligns the accounting for such costs with the guidance on capitalizing costs associated with developing or obtaining internal-use software. For calendar year-end entities, the update will be effective for annual periods beginning on January 1, 2020. Early adoption is permitted, including adoption in an interim period. The amendments in this update may be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. PGE does not expect the adoption to have a material impact on the consolidated financial statements and does not plan to early adopt.

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

Recently Adopted Accounting Pronouncements

On January 1, 2019, PGE adopted ASU 2016-02, *Leases* (Topic 842), which supersedes the previous lease accounting requirements for lessees and lessors within Topic 840, *Leases*. The Company elected the practical expedient provided under ASU 2018-11, *Leases (Topic 842) Targeted Improvements*, which amended ASU 2016-02 to provide entities an optional transition practical expedient to adopt the new standard with a cumulative effect adjustment as of the beginning of the year of adoption with prior year comparative financial information and disclosures remaining as previously reported. As a result, no adjustments were made to the balance sheet prior to January 1, 2019 and amounts are reported in accordance with historical accounting under Topic 840, while the balance sheet as of December 31, 2019 is presented under Topic 842. The Company also elected the practical expedient provided under ASU 2018-01, *Leases (Topic 842) Land Easement Practical Expedient for Transition to Topic 842*, which amended ASU 2016-02 to provide entities an optional transition practical expedient to not evaluate under Topic 842, existing or expired land easements that were not previously accounted for as leases under the previous leases guidance in Topic 840. Effective January 1, 2019, PGE evaluates new or modified land easements under Topic 842.

PGE's transition to the new lease standard did not result in a material adjustment to beginning retained earnings and the Company expects the adoption of the new standard to have an immaterial impact to its results of operations on an ongoing basis. Upon transition, PGE elected to reassess all arrangements that may contain a lease and their resulting lease classification which resulted in the following balance sheet adjustments as of January 1, 2019: i) the recognition of right-of-use assets and liabilities from operating and finance leases of $44 million pursuant to the new standard; ii) the derecognition of existing build-to-suit assets and liabilities of $131 million that were no longer considered to meet build-to-suit criteria under Topic 842 and were not recognized on the Company’s balance sheet until commencement, which occurred in the second quarter of 2019; and iii) the derecognition of $49 million in lease assets and liabilities related to an existing gas pipeline lateral capital lease that no longer met the definition of a lease under the new standard. The following table illustrates the adjustments made upon adoption of Topic 842 and the corresponding line items affected on the Company’s consolidated balance sheets (in millions):

	January 1, 2019 Topic 842 Adoption Adjustments			
	Increase due to existing operating and finance leases	**Decrease due to build-to-suit reassessment**	**Decrease due to capital lease reassessment**	**Total Increase/ (Decrease)**
Assets				
Electric utility plant, net	$ 2	$ (131)	$ (49)	$ (178)
Other noncurrent assets	42	—	—	42
Liabilities				
Accrued expenses and other current liabilities	5	—	(2)	3
Other noncurrent liabilities	39	(131)	(47)	(139)

For new required disclosures and further information see Note 17, Leases. The transition to the new standard did not have a material impact on the Company's financial position.

On January 1, 2019 PGE adopted ASU 2018-02 *Income Statement—Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income* (ASU 2018-02). ASU 2018-02 allows for a reclassification from accumulated other comprehensive income to retained earnings for the stranded tax effects resulting from the United States Tax Cuts and Jobs Act of 2017 (TCJA). The amendments only relate to the reclassification of the income tax effects of the TCJA, and therefore the underlying guidance that requires that the effect of a change in tax laws or rates be included in income from continuing operations is not affected. As a result, PGE reclassified $2 million from Accumulated other compressive loss to Retained earnings during the period of adoption rather than applying the standard retrospectively. The implementation did not result in a material impact to the results of operation, financial position or statements of cash flows.

NOTE 3: REVENUE RECOGNITION

Disaggregated Revenue

The following table presents PGE's revenue, disaggregated by customer type (in millions):

	Year Ended December 31,	
	2019	2018
Retail:		
Residential	$ 981	$ 948
Commercial	636	647
Industrial	196	185
Direct access customers	44	43
Subtotal	1,857	1,823
Alternative revenue programs, net of amortization	2	3
Other accrued (deferred) revenues, net[1]	22	(45)
Total retail revenues	1,881	1,781
Wholesale revenues[2]	170	159
Other operating revenues	72	51
Total revenues	$ 2,123	$ 1,991

(1) Amounts for the year ended December 31, 2019 and 2018 is primarily comprised of $23 million of amortization and $45 million of deferral, respectively, related to the 2018 net tax benefits due to the change in corporate tax rate under the TCJA. For further information, see Note 12, Income Taxes.
(2) Wholesale revenues include $50 million and $42 million related to electricity commodity contract derivative settlements for the year ended December 31, 2019 and 2018, respectively. Price risk management derivative activities are included within Total revenues but do not represent revenues from contracts with customers as defined by GAAP, pursuant to Topic 606. For further information, see Note 6, Risk Management.

Retail Revenues

The Company's primary revenue source is the sale of electricity to customers at regulated tariff-based prices. Retail customers are classified as residential, commercial, or industrial. Residential customers include single family housing, multiple family housing (such as apartments, duplexes, and town homes), manufactured homes, and small farms. Residential demand is sensitive to the effects of weather, with demand highest during the winter heating and summer cooling seasons. Commercial customers consist of non-residential customers who accept energy deliveries at voltages equivalent to those delivered to residential customers. Commercial customers include most businesses, small industrial companies, and public street and highway lighting accounts. Industrial customers consist of non-residential customers who accept delivery at higher voltages than commercial customers. Demand from industrial customers is primarily driven by economic conditions, with weather having little impact on energy use by this customer class.

In accordance with state regulations, PGE's retail customer prices are based on the Company's cost of service and are determined through general rate case proceedings and various tariff filings with the OPUC. Additionally, the Company offers pricing options that include a daily market price option, various time-of-use options, and several renewable energy options.

PGE's obligation to sell electricity to retail customers generally represents a single performance obligation representing a series of distinct services that are substantially the same and have the same pattern of transfer to the customer that is satisfied over time as customers simultaneously receive and consume the benefits provided. PGE applies the invoice method to measure its progress towards satisfactorily completing its performance obligations.

Pursuant to regulation by the OPUC, PGE is mandated to maintain several tariff schedules to collect funds from customers associated with activities for the benefit of the general public, such as conservation, low-income housing, energy efficiency, renewable energy programs, and privilege taxes. For such programs, PGE generally collects the funds and remits the amounts to third party agencies that administer the programs. In these arrangements, PGE is considered to be an agent, as PGE's performance obligation is to facilitate a transaction between customers and the administrators of these programs. Therefore, such amounts are presented on a net basis and do not appear in Revenues, net within the consolidated statements of income.

Wholesale Revenues

PGE participates in the wholesale electricity marketplace in order to balance its supply of power to meet the needs of its retail customers. Interconnected transmission systems in the western United States serve utilities with diverse load requirements and allow the Company to purchase and sell electricity within the region depending upon the relative price and availability of power, hydro, solar, and wind conditions, and daily and seasonal retail demand.

PGE's Wholesale revenues are primarily short-term electricity sales to utilities and power marketers that consist of single performance obligations that are satisfied as energy is transferred to the counterparty. The Company may choose to net certain purchase and sale transactions in which it would simultaneously receive and deliver physical power with the same counterparty; in such cases, only the net amount of those purchases or sales required to meet retail and wholesale obligations will be physically settled and recorded in Wholesale revenues.

Other Operating Revenues

Other operating revenues consist primarily of gains and losses on the sale of natural gas volumes purchased that exceeded what was needed to fuel the Company's generating facilities, as well as revenues from transmission services, excess transmission capacity resale, excess fuel sales, utility pole attachment revenues, and other electric services provided to customers.

NOTE 4: BALANCE SHEET COMPONENTS

Accounts Receivable, Net

Accounts receivable is net of an allowance for uncollectible accounts of $5 million as of December 31, 2019 and $15 million as of December 31, 2018. The following is the activity in the allowance for uncollectible accounts (in millions):

	Years Ended December 31,		
	2019	**2018**	**2017**
Balance as of beginning of year	$ 15	$ 6	$ 6
Increase in provision	2	14	6
Amounts written off, less recoveries	(12)	(5)	(6)
Balance as of end of year	$ 5	$ 15	$ 6

Other Current Assets and Accrued Expenses and Other Current Liabilities

Other current assets and Accrued expenses and other current liabilities consist of the following (in millions):

	As of December 31,	
	2019	**2018**
Other current assets:		
Prepaid expenses	$ 63	$ 54
Margin deposits	16	16
Assets from price risk management activities	25	20
	$ 104	$ 90
Accrued expenses and other current liabilities:		
Regulatory liabilities—current	$ 44	$ 36
Accrued employee compensation and benefits	74	66
Accrued dividends payable	36	34
Accrued interest payable	25	27
Accrued taxes payable	33	34
Other	103	71
	$ 315	$ 268

Electric Utility Plant, Net

Electric utility plant, net consist of the following (in millions):

	As of December 31,	
	2019	**2018**
Electric utility plant:		
Generation	$ 4,749	$ 4,600
Transmission	848	580
Distribution	3,917	3,838
General	656	611
Intangible	758	715
Total in service	10,928	10,344
Accumulated depreciation and amortization	(4,095)	(3,803)
Total in service, net	6,833	6,541
Construction work-in-progress	328	346
Electric utility plant, net	$ 7,161	$ 6,887

NOTE 5: FAIR VALUE OF FINANCIAL INSTRUMENTS

PGE determines the fair value of financial instruments, both assets and liabilities recognized and not recognized in the Company's consolidated balance sheets, for which it is practicable to estimate fair value as of December 31, 2019 and 2018. The Company then classifies these financial assets and liabilities based on a fair value hierarchy that is applied to prioritize the inputs to the valuation techniques used to measure fair value. The three levels of the fair value hierarchy and application to the Company are discussed below.

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the measurement date.

Level 2 Pricing inputs include those that are directly or indirectly observable in the marketplace as of the measurement date.

Level 3 Pricing inputs include significant inputs that are unobservable for the asset or liability.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. Assets measured at fair value using net asset value (NAV) as a practical expedient are not categorized in the fair value hierarchy. These assets are listed in the totals of the fair value hierarchy to permit the reconciliation to amounts presented in the financial statements.

PGE recognizes transfers between levels in the fair value hierarchy as of the end of the reporting period for all of its financial instruments. Changes to market liquidity conditions, the availability of observable inputs, or changes in the economic structure of a security marketplace may require transfer of the securities between levels. There were no significant transfers between levels during the years ended December 31, 2019 and 2018, except those presented in this note.

The Company's financial assets and liabilities whose values were recognized at fair value are as follows by level within the fair value hierarchy (in millions):

	As of December 31, 2019				
	Level 1	**Level 2**	**Level 3**	**Other[(2)]**	**Total**
Assets:					
Cash equivalents	$ 26	$ —	$ —	$ —	$ 26
Nuclear decommissioning trust: [(1)]					
Debt securities:					
Domestic government	8	16	—	—	24
Corporate credit	—	9	—	—	9
Money market funds measured at NAV [(2)]	—	—	—	13	13
Non-qualified benefit plan trust: [(3)]					
Money market funds	1	—	—	—	1
Equity securities—domestic	7	—	—	—	7
Debt securities—domestic government	1	—	—	—	1
Price risk management activities: [(1) (4)]					
Electricity	—	9	7	—	16
Natural gas	—	21	1	—	22
	$ 43	$ 55	$ 8	$ 13	$ 119
Liabilities:					
Price risk management activities: [(1) (4)]					
Electricity	$ —	$ 14	$ 105	$ —	$ 119
Natural gas	—	12	—	—	12
	$ —	$ 26	$ 105	$ —	$ 131

(1) Activities are subject to regulation, with gains and losses deferred pursuant to regulatory accounting and included in regulatory assets or regulatory liabilities as appropriate.
(2) Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.
(3) Excludes insurance policies of $29 million, which are recorded at cash surrender value.

(4) For further information regarding price risk management derivatives, see Note 6, Risk Management.

	As of December 31, 2018				
	Level 1	Level 2	Level 3	Other[(2)]	Total
Assets:					
Cash equivalents	$ 112	$ —	$ —	$ —	$ 112
Nuclear decommissioning trust: [(1)]					
Debt securities:					
Domestic government	7	18	—	—	25
Corporate credit	—	10	—	—	10
Money market funds measured at NAV [(2)]	—	—	—	7	7
Non-qualified benefit plan trust: [(3)]					
Money market funds	2	—	—	—	2
Equity securities—domestic	6	—	—	—	6
Debt securities—domestic government	1	—	—	—	1
Price risk management activities: [(1) (4)]					
Electricity	—	9	3	—	12
Natural gas	—	8	—	—	8
	$ 128	$ 45	$ 3	$ 7	$ 183
Liabilities:					
Interest rate swap derivatives	$ —	$ 4	$ —	$ —	4
Price risk management activities: [(1) (4)]					
Electricity	—	10	84	—	94
Natural gas	—	51	7	—	58
	$ —	$ 65	$ 91	$ —	$ 156

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in regulatory assets or regulatory liabilities as appropriate.
(2) Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.
(3) Excludes insurance policies of $27 million, which are recorded at cash surrender value.
(4) For further information regarding price risk management derivatives, see Note 6, Risk Management.

Cash equivalents are highly liquid investments with maturities of three months or less at the date of acquisition and primarily consist of money market funds. Such funds seek to maintain a stable net asset value and are comprised of short-term, government funds. Policies of such funds require that the weighted-average maturity of securities held by the funds do not exceed 90 days and investors have the ability to redeem shares daily at the net asset value of the respective fund. These cash equivalents are classified as Level 1 in the fair value hierarchy due to the availability of quoted prices for identical assets in an active market as of the measurement date. Principal markets for money market fund prices include published exchanges such as National Association of Securities Dealers Automated Quotations (NASDAQ) and the New York Stock Exchange (NYSE).

Assets held in the NDT and NQBP trusts are recorded at fair value in PGE's consolidated balance sheets and invested in securities that are exposed to interest rate, credit, and market volatility risks. These assets are classified within Level 1, 2, or 3 based on the following factors:

Debt securities—PGE invests in highly-liquid United States Treasury securities to support the investment objectives of the trusts. These domestic government securities are classified as Level 1 in the fair value hierarchy due to the availability of quoted prices for identical assets in an active market as of the measurement date.

Assets classified as Level 2 in the fair value hierarchy include domestic government debt securities, such as municipal debt, and corporate credit securities. Prices are determined by evaluating pricing data such as broker quotes for similar securities and adjusted for observable differences. Significant inputs used in valuation models generally include benchmark yield and issuer spreads. The external credit rating, coupon rate, and maturity of each security are considered in the valuation, as applicable.

Equity securities—Equity mutual fund and common stock securities are classified as Level 1 in the fair value hierarchy due to the availability of quoted prices for identical assets in an active market as of the measurement date. Principal markets for equity prices include published exchanges such as NASDAQ and the NYSE.

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

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

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

Assets and liabilities from price risk management activities are recorded at fair value in PGE's consolidated balance sheets and consist of derivative instruments entered into by the Company to manage its exposure to commodity price risk and foreign currency exchange rate risk and to reduce volatility in NVPC. For additional information regarding these assets and liabilities, see Note 6, Risk Management.

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

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

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

Commodity Contracts	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Price per Unit Low	Price per Unit High	Price per Unit Weighted Average
	(in millions)						
As of December 31, 2019:							
Electricity physical forward	$ —	$ 104	Discounted cash flow	Electricity forward price (per MWh)	$ 12.53	$ 59.00	$ 36.92
Natural gas financial swaps	1	—	Discounted cash flow	Natural gas forward price (per Dth)	1.39	3.73	1.90
Electricity financial futures	7	1	Discounted cash flow	Electricity forward price (per MWh)	10.57	66.32	45.11
	$ 8	$ 105					
As of December 31, 2018:							
Electricity physical forward	$ 3	$ 84	Discounted cash flow	Electricity forward price (per MWh)	$ 14.60	$ 69.00	$ 45.00
Natural gas financial swaps	—	7	Discounted cash flow	Natural gas forward price (per Dth)	0.95	4.64	1.82
Electricity financial futures	—	—	Discounted cash flow	Electricity forward price (per MWh)	20.75	35.46	28.63
	$ 3	$ 91					

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,	
	2019	2018
Net liabilities from price risk management activities as of beginning of year	$ 88	$ 139
Net realized and unrealized losses/(gains) *	10	(40)
Net transfers out of Level 3 to Level 2	(1)	(11)
Net liabilities from price risk management activities as of end of year	$ 97	$ 88
Level 3 net unrealized losses/(gains) that have been fully offset by the effect of regulatory accounting	$ 16	$ (32)

* Includes $6 million in net realized gains in 2019 and $8 million in 2018.

Transfers into Level 3 occur when significant inputs used to value the Company's derivative instruments become less observable, such as a delivery location becoming significantly less liquid. During the years ended December 31, 2019 and 2018, there were no transfers into Level 3 from Level 2. Transfers out of Level 3 occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery term of a transaction becomes shorter. PGE records transfers in and transfers out of Level 3 at the end of the reporting period for all of its derivative instruments.

Transfers from Level 2 to Level 1 for the Company's price risk management assets and liabilities do not occur as quoted prices are not available for identical instruments. As such, the Company's assets and liabilities from price risk management activities mature and settle as Level 2 fair value measurements.

Long-term debt is recorded at amortized cost in PGE's consolidated balance sheets. 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, 2019, the carrying amount of PGE's long-term debt was $2,597 million, net of $11 million of unamortized debt expense, and its estimated aggregate fair value was $3,039 million. As of December 31, 2018, the carrying amount of PGE's long-term debt was $2,478 million, net of $10 million of unamortized debt expense, with an estimated aggregate fair value of $2,760 million.

For fair value information concerning the Company's pension plan assets, see Note 11, Employee Benefits.

NOTE 6: RISK MANAGEMENT

Price Risk Management

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

PGE utilizes derivative instruments to manage its exposure to commodity price risk and foreign exchange rate risk in order to manage volatility in NVPC for its retail customers. Such derivative instruments, recorded at fair value on the consolidated balance sheets, may include forward, futures, swap, and option contracts for electricity, natural gas, and foreign currency, with changes in fair value recorded in the consolidated statements of income. In accordance with ratemaking and cost recovery processes authorized by the OPUC, the Company recognizes a regulatory asset or liability to defer the gains and losses from derivative activity until settlement of the associated derivative instrument. PGE may designate certain derivative instruments as cash flow hedges or may use derivative instruments as economic hedges. The Company does not 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,	
	2019	2018
Current assets:		
Commodity contracts:		
Electricity	$ 9	$ 11
Natural gas	16	7
Total current derivative assets[(1)]	25	18
Noncurrent assets:		
Commodity contracts:		
Electricity	7	1
Natural gas	6	1
Total noncurrent derivative assets[(1)]	13	2
Total derivative assets[(2)]	$ 38	$ 20
Current liabilities:		
Commodity contracts:		
Electricity	$ 14	$ 16
Natural gas	9	35
Total current derivative liabilities	23	51
Noncurrent liabilities:		
Commodity contracts:		
Electricity	105	78
Natural gas	3	23
Total noncurrent derivative liabilities	108	101
Total derivative liabilities[(2)]	$ 131	$ 152

(1) Total current derivative assets is included in Other current assets, and Total noncurrent derivative assets is included in Other noncurrent assets on the consolidated balance sheets.
(2) As of December 31, 2019 and 2018, no commodity derivative assets or liabilities were designated as hedging instruments.

PGE's net volumes related to its Assets and Liabilities from price risk management activities resulting from its derivative transactions, which are expected to deliver or settle at various dates through 2035, were as follows (in millions):

	As of December 31,					
	2019			2018		
Commodity contracts:						
Electricity		6	MWh		5	MWh
Natural gas		145	Dth		123	Dth
Foreign currency exchange	$	23	Canadian	$	18	Canadian

PGE has elected to report positive and negative exposures resulting from derivative instruments pursuant to agreements that meet the definition of a master netting arrangement at gross values on the consolidated balance sheet. In the case of default on, or termination of, any contract under the master netting arrangements, such agreements provide for the net settlement of all related contractual obligations with a given counterparty through a single payment. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, receivables and payables arising from settled positions, and other forms of non-cash collateral, such as letters of credit. As of December 31, 2019, PGE had no material gross master netting arrangements. As of December 31, 2018, gross amounts included as Price risk management liabilities subject to master netting agreements were $88 million, for which PGE posted collateral of $11 million, which consisted entirely of letters of credit. Of the gross amounts recognized as of December 31, 2018, $84 million was for electricity and $4 million was for natural gas.

Net realized and unrealized losses (gains) on derivative transactions not designated as hedging instruments are classified in Purchased power and fuel in the consolidated statements of income and were as follows (in millions):

	Years Ended December 31,					
	2019		2018		2017	
Commodity contracts:						
Electricity	$	20	$	(34)	$	41
Natural Gas		(32)		21		85
Foreign currency exchange		(1)		1		(1)

Net unrealized and certain net realized losses (gains) presented in the table above are offset within the consolidated statements of income by the effects of regulatory accounting. Of the net amounts recognized in Net income, net gains of $2 million, net gains of $18 million, and net losses of $82 million for the years ended December 31, 2019, 2018, and 2017, respectively, have been offset.

Assuming no changes in market prices and interest rates, the following table presents the years in which the net unrealized (gains)/losses recorded as of December 31, 2019 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2020		2021		2022		2023		2024		Thereafter		Total	
Commodity contracts:														
Electricity	$	5	$	1	$	7	$	7	$	7	$	76	$	103
Natural gas		(7)		(2)		(1)		—		—		—		(10)
Net unrealized (gain)/loss	$	(2)	$	(1)	$	6	$	7	$	7	$	76	$	93

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, 2019 was $122 million, for which the Company has posted $15 million in collateral, consisting entirely of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered as of December 31, 2019, the cash requirement to either post as collateral or settle the instruments immediately would have been $114 million. As of December 31, 2019, PGE had no posted cash collateral for derivative instruments with no credit-risk-related contingent features. Cash collateral for derivative instruments is classified as Margin deposits included in Other current assets on the Company's consolidated balance sheet.

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

	As of December 31,	
	2019	**2018**
Assets from price risk management activities:		
Counterparty A	35%	42%
Counterparty B	1	15
Counterparty C	13	5
Counterparty D	11	6
Counterparty E	11	9
	71%	77%
Liabilities from price risk management activities:		
Counterparty F	79%	56%

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.

Interest Rate Risk

In 2018 PGE entered into two forward starting interest rate swap lock agreements to hedge a portion of its interest rate risk associated with anticipated issuances of fixed-rate, long-term debt securities. These derivative instruments were designated as cash flow hedges, protecting against the risk of changes in future interest payments that could have resulted from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance.

As of December 31, 2018, the fair value of the interest rate swaps was a $4 million liability, which was recorded in Liabilities from price risk management activities - current on the Company's consolidated balance sheets. The swaps settled at a $5 million loss in January 2019, which was recorded in Regulatory assets - noncurrent on the consolidated balance sheets, and will be amortized as a component of interest expense over the life of the associated debt. Such amounts are also included as a component of cost of debt for ratemaking purposes. As of December 31, 2019, the Company had no outstanding interest rate swaps.

NOTE 7: REGULATORY ASSETS AND LIABILITIES

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

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

		As of December 31,			
		2019			2018
	Remaining Amortization Period	Earning a Return [1]	Not Earning a Return	Total	Total
Regulatory assets:					
Price risk management	2035	$ —	$ 95	$ 95	$ 131
Pension and other postretirement plans	[2]	—	213	213	222
Debt issuance costs	2049	—	26	26	16
Trojan decommissioning activities	2059	—	94	94	26
Other	Various	62	10	72	67
Total regulatory assets		$ 62	$ 438	$ 500	$ 462
Regulatory liabilities:					
Asset retirement removal costs	[3]	$ 1,021	$ —	$ 1,021	$ 979
Deferred income taxes	[4]	260	—	260	267
Asset retirement obligations	[3]	54	—	54	53
Tax reform deferral [5]	2020	23	—	23	45
Other	Various	47	16	63	47
Total regulatory liabilities		$ 1,405	$ 16	$ 1,421	$ 1,391

(1) Earning a return includes either interest on the regulatory asset or liability, or inclusion of the regulatory asset or liability as an increase or decrease to rate base at the allowed rate of return.
(2) Recovery expected over the average service life of employees.
(3) Recovery or refund expected over the estimated lives of the underlying assets and treated as a reduction to rate base.
(4) Refund expected primarily through amortization using the average rate assumption method over the average life of the underlying assets and treated as a reduction to rate base.
(5) Refund related to the deferral of the 2018 net tax benefits due to the change in corporate tax rate under TCJA, including interest, over a two-year period that began in 2019.

Price risk management represents the difference between the net unrealized losses recognized on derivative instruments related to price risk management activities and their realization and subsequent recovery in customer prices. For further information regarding assets and liabilities from price risk management activities, see Note 6, Risk Management.

Pension and other postretirement plans represents unrecognized components of the benefit plans' funded status, which are recoverable in customer prices when recognized in net periodic pension and postretirement benefit costs. For further information, see Note 11, Employee Benefits.

Debt issuance costs represents unrecognized debt issuance costs related to debt instruments retired prior to the stipulated maturity date.

Trojan decommissioning activities represents the deferral of ongoing costs associated with monitoring spent nuclear fuel at Trojan, net of amortization of customer collections. In addition, proceeds received from the United States Department of Energy (USDOE) for the reimbursement of costs to monitor the ISFSI is deferred and subsequently refunded to customers.

Asset retirement removal costs represents the costs that do not qualify as AROs and are a component of depreciation expense allowed in customer prices. Such costs are recorded as a regulatory liability as they are collected in prices, and are reduced by actual removal costs incurred.

Deferred income taxes represents income tax benefits primarily from property-related timing differences that will be refunded to customers when the temporary differences reverse. Substantially all of the amounts deferred are subject to tax normalization rules that require that the impact to the results of operations of amortizing the excess deferred income tax balance cannot occur more rapidly than over the book life of the related assets. The Company uses the average rate assumption method to account for the refund to customers. For further information, see Note 12, Income Taxes.

Asset retirement obligations represents the difference in the timing of recognition of: i) the amounts recognized for depreciation expense of the asset retirement costs and accretion of the ARO; and ii) the amount recovered in customer prices.

NOTE 8: ASSET RETIREMENT OBLIGATIONS

AROs consist of the following (in millions):

	As of December 31,	
	2019	**2018**
Trojan decommissioning activities	$ 137	$ 68
Utility plant	126	112
Non-utility property	16	17
Total asset retirement obligations	279	197
Less: current portion *	16	—
Noncurrent asset retirement obligations	$ 263	$ 197

* Current portion of AROs are classified within Accrued expenses and other current liabilities in the consolidated balance sheets.

Trojan decommissioning activities represents the present value of future decommissioning costs for PGE's 67.5% ownership interest in Trojan, which ceased operation in 1993. The remaining decommissioning activities primarily consist of the long-term operation and decommissioning of the ISFSI, an interim dry storage facility that is licensed by the Nuclear Regulatory Commission (NRC). 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 the third quarter of 2019, the NRC issued PGE a renewed license to operate the ISFSI through the first quarter of 2059. PGE updated its ARO to reflect the estimated costs through this date which increased the Trojan ARO by $69 million as of December 31, 2019. The Company also recorded accretion of $4 million and a reduction of $4 million due to settled liabilities.

Under a settlement agreement reached with the USDOE, the Company receives annual reimbursement from the USDOE for certain costs related to monitoring the ISFSI. Pursuant to this process, the USDOE reimbursed the co-owners $4 million in 2019 for costs incurred in 2018 and $4 million in 2018 for costs incurred in 2017 resulting from USDOE delays in accepting spent nuclear fuel.

Utility plant represents AROs that have been recognized for the Company's thermal and wind generation sites, and distribution and transmission assets, the disposal of which is governed by environmental regulation. During 2019, the Company recorded an overall increase in utility AROs of $14 million, with the change comprised of revisions in estimated cash flows of $13 million, accretion of $4 million, and a reduction of $3 million due to settled liabilities.

In 2019, the Company recorded an $11 million increase to its ARO related to Colstrip to revise the estimated cash flows associated with remediation of a number of settlement ponds that will require upgrading or closure to meet Montana Department of Environmental Quality regulatory requirements.

Non-utility property primarily represents AROs that have been recognized for portions of unregulated properties leased to third parties. Revisions to estimates for non-utility AROs are not subject to regulatory deferral. As such, additions in non-utility AROs are charged directly to the consolidated statement of income in the period in which the revisions are probable and reasonably estimable.

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

	Years Ended December 31,		
	2019	2018	2017
Balance as of beginning of year	$ 197	$ 167	$ 161
Liabilities incurred	—	—	2
Liabilities settled	(9)	(5)	(3)
Accretion expense	9	8	7
Revisions in estimated cash flows	82	27	—
Balance as of end of year	$ 279	$ 197	$ 167

Pursuant to regulation, the amortization of utility plant AROs is included in depreciation expense and in customer prices. Any differences in the timing of recognition of costs for financial reporting and ratemaking purposes are deferred as a regulatory asset or regulatory liability. Recovery of Trojan decommissioning costs is included in PGE's retail prices with an equal amount recorded in Depreciation and amortization expense.

PGE maintains a separate trust account, Nuclear decommissioning trust in the consolidated balance sheet, for funds collected from customers through prices to cover the cost of Trojan decommissioning activities.

The Oak Grove hydro facility and transmission and distribution plant located on public right-of-ways and on certain easements meet the requirements of a legal obligation and will require removal when the plant is no longer in service. An ARO liability is not currently measurable as management believes that these assets will be used in utility operations for the foreseeable future. Removal costs are charged to accumulated asset retirement removal costs, which is included in Regulatory liabilities on PGE's consolidated balance sheets.

NOTE 9: CREDIT FACILITIES

As of December 31, 2019, PGE had a $500 million revolving credit facility scheduled to expire in November 2023. The credit facility allows for unlimited extension requests, provided that lenders with a pro-rata share of more than 50% approve the extension request.

Pursuant to the terms of the agreement, the revolving credit facility may be used for general corporate purposes, as backup for commercial paper borrowings, and to permit the issuance of standby letters of credit. PGE may borrow for one, two, three, or six at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the applicable credit facility. The revolving credit facility contains a provision that requires annual fees based on PGE's unsecured credit ratings, and contains customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the agreement, to

65.0% of total capitalization. As of December 31, 2019, PGE was in compliance with this covenant with a 51.9% debt to total capital ratio.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days, limited to the unused amount of credit under the revolving credit facility.

PGE classifies any borrowings under the revolving credit facility and outstanding commercial paper as Short-term debt in the consolidated balance sheets.

Under the revolving credit facility, as of December 31, 2019, PGE had no borrowings outstanding and there were no commercial paper or letters of credit issued. As a result, the aggregate unused available credit capacity under the revolving credit facility was $500 million.

In addition, PGE has four letter of credit facilities that provide a total capacity of $220 million under which the Company can request letters of credit for original terms not to exceed one year. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these facilities, a total of $55 million of letters of credit were outstanding as of December 31, 2019. Outstanding letters of credit are not reflected on the Company's consolidated balance sheets.

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 7, 2022.

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

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

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

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

NOTE 10: LONG-TERM DEBT

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

	As of December 31,	
	2019	2018
First Mortgage Bonds, rates range from 2.51% to 9.31%, with a weighted average rate of 4.63% in 2019 and 5.01% in 2018, due at various dates through 2050	$ 2,510	$ 2,390
Pollution Control Revenue Bonds, rates at 5%, due 2033	119	119
Pollution Control Revenue Bonds held by PGE	(21)	(21)
Total long-term debt	2,608	2,488
Less: Unamortized debt expense	(11)	(10)
Less: Current portion of long-term debt	—	(300)
Long-term debt, net of current portion	$ 2,597	$ 2,178

First Mortgage Bonds—On April 12, 2019, PGE issued $200 million of 4.30% Series FMBs due in 2049. Proceeds from the transaction were used to repay the $300 million current portion of long-term debt on April 15, 2019.

On October 25, 2019, PGE entered into an agreement to issue $270 million of privately placed FMBs in two tranches, both of which bear interest from their issue date at an annual rate of 3.34%. The first tranche, $110 million, with a maturity in 2049, was issued on October 25, 2019, a portion of which was used to redeem $50 million of 6.75% FMBs that had a maturity date in 2023. The second tranche, $160 million, with a maturity in 2050, was issued and funded November 15, 2019.

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

Pollution Control Revenue Bonds—The Company has the option to remarket through 2033 the $21 million PCRBs held by PGE as of December 31, 2019. At the time of any remarketing, the Company can choose a new interest rate period that could be daily, weekly, or a fixed term. The new interest rate would be based on market conditions at the time of remarketing. The 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, 2019, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:	
2020	$ —
2021	160
2022	—
2023	—
2024	80
Thereafter	2,368
	$ 2,608

NOTE 11: EMPLOYEE BENEFITS

Pension and Other Postretirement Plans

Defined Benefit Pension Plan—PGE sponsors a non-contributory defined benefit pension plan, which has been closed to new employees since January 1, 2012. No changes were made to the benefits provided to existing participants when the plan was closed to new employees.

The assets of the pension plan are held in a trust and are comprised of equity and debt instruments, all of which are recorded at fair value. Pension plan calculations include several assumptions that are reviewed annually and updated as appropriate.

PGE contributed $62 million to the pension plan in 2019 and $9 million in 2018. PGE does not expect to contribute to the pension plan in 2020.

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. In the third quarter of 2019, PGE announced an amendment to its HRAs and defined dollar medical benefit for non-represented employees, resulting in a $2 million curtailment gain, which has been recorded in Miscellaneous income (expense), net on the consolidated statement of income.

The assets of these plans are held in voluntary employees' beneficiary association trusts and are comprised of money market funds, equity securities, common and collective trust funds, partnerships/joint ventures, and registered investment companies, all of which are recorded at fair value. Postretirement health and life insurance benefit plan calculations include several assumptions that are reviewed annually by PGE and updated as appropriate, with measurement dates of December 31.

Non-Qualified Benefit Plan—The NQBP in the following tables include obligations for a Supplemental Executive Retirement Plan and a directors pension plan, both of which were closed to new participants in 1997. The NQBP also includes pension make-up benefits for employees that participate in the unfunded Management Deferred Compensation Plan (MDCP). Investments in the NQBP trust, consisting of trust-owned life insurance policies and marketable securities, provide funding for the future requirements of these plans. The assets of such trust are included in the accompanying tables for informational purposes only and are not considered segregated and restricted under current accounting standards. The investments in marketable securities, consisting of money market, bonds, and equity mutual funds, are classified as equity or trading debt securities and recorded at fair value. The measurement date for the NQBP is December 31. For further information regarding these trust investments, see Note 5, Fair Value of Financial Instruments.

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

Trust assets and plan liabilities related to the NQBP included in PGE's consolidated balance sheets are as follows as of December 31 (in millions):

	2019			2018		
	NQBP	Other NQBP	Total	NQBP	Other NQBP	Total
Non-qualified benefit plan trust	$ 17	$ 21	$ 38	$ 16	$ 20	$ 36
Non-qualified benefit plan liabilities *	24	79	103	22	81	103

* For the NQBP, excludes the current portion of $2 million in 2019 and 2018, which are classified in Accrued expenses and other current liabilities in the consolidated balance sheets.

Investment Policy and Asset Allocation—The Board of Directors of PGE appoints an Investment Committee, which is comprised of certain members of management from the Company, and establishes the Company's asset allocation. The Investment Committee is then responsible for the implementation of the asset allocation and oversight of the benefit plan investments. The Company's investment strategy for its pension and other postretirement plans is to balance risk and return through a diversified portfolio of equity securities, fixed income securities, and other alternative investments. Asset classes are regularly rebalanced to ensure asset allocations remain within prescribed parameters.

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

	As of December 31,			
	2019		2018	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Equity securities	64%	65%	65%	67%
Debt securities	36	35	35	33
Total	100%	100%	100%	100%
Other Postretirement Benefit Plans:				
Equity securities	61%	59%	58%	59%
Debt securities	39	41	42	41
Total	100%	100%	100%	100%
Non-Qualified Benefits Plans:				
Equity securities	17%	12%	16%	13%
Debt securities	7	12	10	13
Insurance contracts	76	76	74	74
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, 2019:					
Defined Benefit Pension Plan assets:					
Equity securities—Domestic	$ 49	$ —	$ —	$ —	$ 49
Investments measured at NAV:					
Money market funds	—	—	—	5	5
Collective trust funds	—	—	—	632	632
Private equity funds	—	—	—	9	9
	$ 49	$ —	$ —	$ 646	$ 695
Other Postretirement Benefit Plans assets:					
Money market funds	$ 4	$ —	$ —	$ —	$ 4
Equity securities:					
Domestic	—	3	—	—	3
International	9	—	—	—	9
Debt securities—Domestic	—	5	—	—	5
Investments measured at NAV:					
Money market funds	—	—	—	5	5
Collective trust funds	—	—	—	8	8
	$ 13	$ 8	$ —	$ 13	$ 34
As of December 31, 2018:					
Defined Benefit Pension Plan assets:					
Equity securities—Domestic	$ 67	$ —	$ —	$ —	$ 67
Investments measured at NAV:					
Money market funds	—	—	—	5	5
Collective trust funds	—	—	—	463	463
Private equity funds	—	—	—	11	11
	$ 67	$ —	$ —	$ 479	$ 546
Other Postretirement Benefit Plans assets:					
Money market funds	$ 3	$ —	$ —	$ —	$ 3
Equity securities:					
Domestic	—	3	—	—	3
International	8	—	—	—	8
Debt securities—Domestic government	—	5	—	—	5
Investments measured at NAV:					
Money market funds	—	—	—	4	4
Collective trust funds	—	—	—	7	7
	$ 11	$ 8	$ —	$ 11	$ 30

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

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

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

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

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

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

Private equity funds—PGE invests in a combination of primary and secondary fund-of-funds, which hold ownership positions in privately held companies across the major domestic and international private equity sectors, including but not limited to, partnerships, joint ventures, venture capital, buyout, and special situations. Private equity investments are valued at NAV as a practical expedient and are not classified in the fair value hierarchy.

The following tables provide certain information with respect to the Company's defined benefit pension plan, other postretirement benefits, and NQBP as of and for the years ended December 31, 2019 and 2018. Information related to the Other NQBP is not included in the following tables (dollars in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2019	2018	2019	2018	2019	2018
Benefit obligation:						
As of January 1	$ 811	$ 869	$ 72	$ 78	$ 24	$ 27
Service cost	16	19	2	2	—	—
Interest cost	34	32	3	3	1	1
Participants' contributions	—	—	2	2	—	—
Actuarial loss (gain)	88	(67)	8	(7)	3	(1)
Benefit payments	(42)	(39)	(6)	(6)	(2)	(3)
Administrative expenses	(2)	(3)	—	—	—	—
Plan amendment	—	—	(9)	—	—	—
Curtailment gain	—	—	(1)	—	—	—
As of December 31	$ 905	$ 811	$ 71	$ 72	$ 26	$ 24
Fair value of plan assets:						
As of January 1	$ 546	$ 629	$ 30	$ 33	$ 16	$ 17
Actual return on plan assets	131	(50)	5	(2)	1	(1)
Company contributions	62	9	3	3	2	3
Participants' contributions	—	—	2	2	—	—
Benefit payments	(42)	(39)	(6)	(6)	(2)	(3)
Administrative expenses	(2)	(3)	—	—	—	—
As of December 31	$ 695	$ 546	$ 34	$ 30	$ 17	$ 16
Unfunded position as of December 31	$ (210)	$ (265)	$ (37)	$ (42)	$ (9)	$ (8)
Accumulated benefit plan obligation as of December 31	$ 813	$ 734	N/A	N/A	$ 26	$ 24
Classification in consolidated balance sheet:						
Noncurrent asset	$ —	$ —	$ —	$ —	$ 17	$ 16
Current liability	—	—	—	—	(2)	(2)
Noncurrent liability	(210)	(265)	(37)	(42)	(24)	(22)
Net liability	$ (210)	$ (265)	$ (37)	$ (42)	$ (9)	$ (8)
Amounts included in comprehensive income:						
Net actuarial loss (gain)	$ (3)	$ 25	$ 5	$ (4)	$ 3	$ (1)
Net prior service credit	—	—	(9)	—	—	—
Amortization of net actuarial loss	(10)	(17)	—	—	(1)	(1)
	$ (13)	$ 8	$ (4)	$ (4)	$ 2	$ (2)
Amounts included in AOCL:*						
Net actuarial loss (gain)	$ 213	$ 226	$ 1	$ (4)	$ 13	$ 11
Prior service cost	—	—	(9)	—	—	—
	$ 213	$ 226	$ (8)	$ (4)	$ 13	$ 11

* Amounts included in AOCL related to the Company's defined benefit pension plan and other postretirement benefits are transferred to Regulatory assets due to the future recoverability from retail customers. Accordingly, as of the balance sheet date, such amounts are included in Regulatory assets.

Net periodic benefit cost consists of the following for the years ended December 31 (in millions):

	Defined Benefit Pension Plan			Other Postretirement Benefits			Non-Qualified Benefit Plans		
	2019	2018	2017	2019	2018	2017	2019	2018	2017
Service cost	$ 16	$ 19	$ 17	$ 2	$ 2	$ 2	$ —	$ —	$ —
Interest cost on benefit obligation	34	32	33	3	3	3	1	1	1
Expected return on plan assets	(40)	(42)	(42)	(2)	(1)	(2)	—	—	—
Amortization of net actuarial loss	10	17	13	—	—	—	1	1	1
Curtailment gain	—	—	—	(2)	—	—	—	—	—
Net periodic benefit cost	$ 20	$ 26	$ 21	$ 1	$ 4	$ 3	$ 2	$ 2	$ 2

The portion of non-service costs attributable to expense related to the pension and other postretirement benefit plans, is classified as Miscellaneous income (expense), net within Other income on the Company's consolidated statements of income. PGE estimates that $17 million will be amortized from AOCL into net periodic benefit cost in 2020, consisting of a net actuarial loss of $17 million for pension benefits, a net actuarial gain and prior service credit of $1 million for other postretirement benefits and a net actuarial loss of $1 million for non-qualified benefits. Amounts related to the pension and other postretirement benefits are offset with the amortization of the corresponding regulatory asset.

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

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2019	2018	2019	2018	2019	2018
Assumptions used to determine benefit obligations:						
Discount rate	3.43%	4.25%	3.19% - 3.47%	4.10% - 4.26%	3.43%	4.25%
Weighted average rate of compensation increase	3.65%	3.65%	4.58%	4.58%	N/A	N/A
Assumptions used to determine net periodic benefit cost:						
Discount rate	4.25%	3.65%	3.11% - 4.26%	3.42% - 3.70%	3.43%	3.65%
Weighted average rate of compensation increase	3.65%	3.65%	4.58%	4.58%	N/A	N/A
Long-term rate of return on plan assets	7.00%	7.00%	5.88%	6.20%	N/A	N/A

As of December 31, 2019, there are no liabilities with sensitivity to health care cost trend rates.

Changes in actuarial assumptions can also have a material effect on net periodic pension expense. A 0.25% reduction in the expected long-term rate of return on plan assets, or reduction in the discount rate, would have the effect of increasing the 2019 net periodic pension expense by approximately $2 million.

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					
	2020	2021	2022	2023	2024	2025 - 2029
Defined benefit pension plan	$ 44	$ 44	$ 45	$ 46	$ 46	$ 239
Other postretirement benefits	5	5	5	5	6	20
Non-qualified benefit plans	2	2	2	2	2	11
Total	$ 51	$ 51	$ 52	$ 53	$ 54	$ 270

All of the plans develop expected long-term rates of return for the major asset classes using long-term historical returns, with adjustments based on current levels and forecasts of inflation, interest rates, and economic growth. Also included are incremental rates of return provided by investment managers whose returns are expected to be greater than the markets in which they invest.

401(k) Retirement Savings Plan

PGE sponsors a 401(k) Plan that covers substantially all employees. For eligible employees who are covered by PGE's defined benefit pension plan, the Company matches employee contributions to the 401(k) Plan up to 6% of the employee's base pay. For eligible employees who are not covered by PGE's defined benefit pension plan, the Company contributes 5% of the employee's base salary, whether or not the employee contributes to the 401(k) Plan, and also matches employee contributions up to 5% of the employee's base pay.

For the majority of bargaining employees who are subject to the International Brotherhood of Electrical Workers Local 125 agreements the Company contributes an additional 1% of the employee's base salary, whether or not the employee contributes to the 401(k) Plan.

All contributions are invested in accordance with employees' elections, limited to investment options available under the 401(k) Plan. PGE made contributions to employee accounts of $25 million in 2019, $23 million in 2018, and $21 million in 2017.

NOTE 12: INCOME TAXES

On December 22, 2017, the TCJA was enacted and signed into law with substantially all of the provisions having an effective date of January 1, 2018. The most significant change to PGE's financial condition was the federal corporate tax rate decrease from 35% to 21%.

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

	Years Ended December 31,		
	2019	2018	2017
Current:			
Federal	$ 9	$ 12	$ 4
State and local	12	22	12
	21	34	16
Deferred:			
Federal	(2)	(15)	61
State and local	8	(2)	9
	6	(17)	70
Income tax expense	$ 27	$ 17	$ 86

The significant differences between the U.S. federal statutory rate and PGE's effective tax rate for financial reporting purposes are as follows:

	Years Ended December 31,		
	2019	2018	2017
Federal statutory tax rate	21.0%	21.0%	35.0%
Federal tax credits[1]	(13.4)	(16.7)	(14.0)
Change in federal tax law[2]	—	—	6.1
State and local taxes, net of federal tax benefit	6.5	6.5	5.0
Flow through depreciation and cost basis differences	1.5	1.5	1.5
Excess deferred tax amortization[3]	(3.7)	(4.1)	—
Other	(0.7)	(0.8)	(2.1)
Effective tax rate	11.2%	7.4%	31.5%

(1) Federal tax credits consist primarily of production tax credits (PTCs) earned from Company-owned wind-powered generating facilities. The federal PTCs are earned based on a per-kilowatt hour rate, and as a result, the annual amount of PTCs earned will vary based on weather conditions and availability of the facilities. The PTCs are generated for 10 years from the corresponding facilities' in-service dates. PGE's PTC generation ended or will end at various dates between 2017 and 2024.
(2) For the year ended December 31, 2017, includes a $17 million increase to Income tax expense related to the remeasurement of deferred income taxes as a result of the enacted tax rate change under the TCJA.
(3) The majority of excess deferred income taxes related to remeasurement under the TCJA is subject to IRS normalization rules and will be amortized over the remaining regulatory life of the assets using the average rate assumption method.

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

	As of December 31,	
	2019	2018
Deferred income tax assets:		
Employee benefits	$ 119	$ 134
Price risk management	26	36
Regulatory liabilities	22	26
Tax credits	64	52
Other	—	9
Total deferred income tax assets	231	257
Deferred income tax liabilities:		
Depreciation and amortization	496	511
Regulatory assets	103	115
Other	10	—
Total deferred income tax liabilities	609	626
Deferred income tax liability, net	$ 378	$ 369

As of December 31, 2019, PGE has federal credit carryforwards of $64 million, consisting of PTCs, which will expire at various dates through 2039. PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2019 and 2018 will be realized; accordingly, no valuation allowance has been recorded. As of December 31, 2019, and 2018, PGE had no material unrecognized tax benefits.

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

NOTE 13: EQUITY-BASED PLANS

Employee Stock Purchase Plan

PGE has an employee stock purchase plan (ESPP) under which a total of 625,000 shares of the Company's common stock may be issued. The ESPP permits all eligible employees to purchase shares of PGE common stock through regular payroll deductions, which are limited to 10% of base pay. Each year, employees may purchase up to a maximum of $25,000 in common stock or 1,500 shares (based on fair value on the purchase date), whichever is less. Two six-month offering periods occur annually, January 1 through June 30 and July 1 through December 31, during which eligible employees may contribute toward the purchase of shares of PGE common stock. Purchases occur the last day of the offering period, at a price equal to 95% of the fair value of the stock on the purchase date. As of December 31, 2019, there were 278,098 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, 2019, there were 2,466,470 shares available for future issuance pursuant to the DRIP.

NOTE 14: STOCK-BASED COMPENSATION EXPENSE

Pursuant to the Portland General Electric Company Stock Incentive Plan as amended and restated effective February 13, 2018 (the Plan), the Company may grant a variety of equity-based awards, including restricted stock units (RSUs) with time-based vesting conditions (time-based RSUs) and performance-based vesting conditions (performance-based RSUs), to non-employee directors, officers, or certain key employees. RSU activity is summarized in the following table:

	Units	Weighted Average Grant Date Fair Value
Nonvested units as of December 31, 2016	458,792	$ 34.68
Granted	202,145	41.96
Forfeited	(64,840)	39.57
Vested	(196,721)	31.78
Nonvested units as of December 31, 2017	399,376	37.98
Granted	198,864	37.99
Forfeited	(8,556)	39.73
Vested	(160,771)	36.77
Nonvested units of December 31, 2018	428,913	38.43
Granted	210,555	49.06
Forfeited	(9,041)	41.68
Vested	(167,037)	37.52
Nonvested units as of December 31, 2019	463,390	43.52

A total of 4,687,500 shares of common stock were registered for issuance under the Plan, of which 2,902,576 shares remain available for future issuance as of December 31, 2019.

Outstanding RSUs provide for the payment of one Dividend Equivalent Right (DER) for each stock unit. Each DER represents an amount equal to dividends paid to shareholders on a share of PGE's common stock and vests on the same schedule as the related RSU. The DERs are settled in shares of PGE common stock valued either at the closing stock price on the vesting date (for performance-based RSUs) or dividend payment date (for all other grants).

Time-based RSUs generally vest over a period of up to three years from the grant date. The fair value of time-based RSUs is measured based on the closing price of PGE common stock on the date of grant and charged to compensation expense on a straight-line basis over the requisite service period for the entire award. The total value of time-based RSUs vested was $1 million for the years ended December 31, 2019, 2018, and 2017.

Performance-based RSUs vest based on the extent to which performance goals are met at the end of a three-year performance period, subject to adjustment by the Compensation and Human Resources Committee of PGE's Board of Directors. The number of RSUs that may vest under grants awarded in 2018 and 2017 is based on two equally-weighted metrics: i) actual return on equity relative to allowed return on equity; and ii) a relative total shareholder return (TSR) of PGE's common stock as compared to an index of peer companies during the performance period. Based on the attainment of the goals, the number of RSUs that vest can range from zero to 175% of the RSUs granted. The number of RSUs that may vest under grants awarded in 2019 is based on three equally-weighted metrics: i) actual return on equity relative to allowed return on equity; ii) average EPS growth; and iii) power supply portfolio decarbonization—and relative TSR as a modifier to the total of the three equally-weighted metrics. Based on the attainment of the goals, the number of RSUs that vest can range from zero to 200% of the RSUs granted.

For return on equity, average EPS growth and power supply portfolio decarbonization 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:

	2019	2018	2017
Risk-free interest rate	2.5%	2.4%	1.5%
Expected term (in years)	3.0	3.0	3.0
Volatility	14.8% - 74.5%	14.7% - 21.8%	15.6% - 22.9%

There is no expected dividend yield used in the valuation, as it is assumed that all dividends distributed during the performance period are reinvested in the Company's underlying stock. The fair value of performance-based RSUs is charged to compensation expense on a straight-line basis over the requisite service period for the entire award based on the number of shares expected to vest. Stock-based compensation expense was calculated assuming the attainment of performance goals that would allow the weighted average vesting of 123.0%, 86.6%, and 89.1% of awarded performance-based RSUs for the respective 2019, 2018, and 2017 grants, with an estimated 5% forfeiture rate.

The total value of performance-based RSUs vested was $7 million for the year ended December 31, 2019, $4 million for 2018, and $6 million for 2017.

Stock-based compensation, included in Administrative and other expense in the consolidated statements of income, was $9 million for the year ended December 31, 2019, $5 million for 2018, and $7 million in 2017. Such amounts differ from those reported in the consolidated statements of shareholders' equity for stock-based compensation due primarily to the impact from the income tax payments made on behalf of employees. The Company withholds a portion of the vested shares for the payment of income taxes on behalf of the employees. Not included in Administrative and other expenses in the consolidated statements of income, is the net impact from these income tax payments, partially offset by the issuance of DERs, resulting in a charge to shareholders' equity of $2 million in 2019, and $2 million in 2018 and $3 million in 2017.

As of December 31, 2019, unrecognized stock-based compensation expense was $10 million, which is expected to be recognized over a weighted average period of one to three years. No stock-based compensation costs have been capitalized.

NOTE 15: EARNINGS PER SHARE

Basic earnings per share are computed based on the weighted average number of common shares outstanding during the year. Diluted earnings per share are computed using the weighted average number of common shares outstanding and the effect of dilutive potential common shares outstanding during the year using the treasury stock method. Potential common shares consist of employee stock purchase plan shares and contingently issuable time-based and performance-based RSUs, along with associated DERs.

Net income attributable to PGE common shareholders is the same for both the basic and diluted earnings per share computations. The reconciliations of the denominators of the basic and diluted earnings per share computations are as follows (in thousands):

	Years Ended December 31,		
	2019	2018	2017
Weighted average common shares outstanding—basic	89,353	89,215	89,056
Dilutive effect of potential common shares	206	132	120
Weighted average common shares outstanding—diluted	89,559	89,347	89,176

NOTE 16: COMMITMENTS AND GUARANTEES

Purchase Commitments

As of December 31, 2019, PGE's estimated future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2020	2021	2022	2023	2024	Thereafter	Total
Capital and other purchase commitments	$ 393	$ 130	$ 14	$ 4	$ 1	$ 56	$ 598
Purchased power and fuel:							
Electricity purchases	193	189	220	219	215	2,327	3,363
Capacity contracts	—	9	9	9	9	9	45
Public utility districts	16	15	13	13	12	50	119
Natural gas	59	45	40	38	42	603	827
Coal and transportation	27	27	27	27	27	27	162
Total	$ 688	$ 415	$ 323	$ 310	$ 306	$ 3,072	$ 5,114

Capital and other purchase commitments—Certain commitments have been made for 2020 and beyond that include those related to hydro licenses, upgrades to generation, distribution, and transmission facilities, information systems, and system maintenance work. Termination of these agreements could result in cancellation charges.

Electricity purchases and Capacity contracts—PGE has power purchase agreements with counterparties, which expire at varying dates through 2051, and power capacity contracts through 2025.

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

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

Under the Grant County agreements, the Company is required to pay its proportionate share of the operating and debt service costs of the hydroelectric projects whether they are operable or not. Under the Douglas County agreement, the Company is required to make monthly payments for capacity that will not vary with annual project generation provided to PGE. The Company has estimated the capacity payments, which are subject to annual adjustments based on Douglas County's loads, and included the estimated amounts in the table above. The future minimum payments for the PUDs in the preceding table reflect the principal and capacity payments only and do not include interest, operation, or maintenance expenses.

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

	Capacity Charges and Revenue Bonds as of December 31, 2019	PGE's Average Share as of December 31, 2019		Contract Expiration	Total PGE Contract Costs		
		Output	Capacity		2019	2018	2017
			(in MW)				
Priest Rapids and Wanapum	$ 1,302	8.6%	163	2052	$ 21	$ 17	$ 16
Wells	651	13.6	98	2028	16	11	11

The agreements for Priest Rapids, Wanapum, and Wells provide that, should any other purchaser of output default on payments as a result of bankruptcy or insolvency, PGE would be allocated a pro-rata share of the output and operating and debt service costs of the defaulting purchaser. For Wells, PGE would be responsible for a pro-rata portion of the defaulting purchaser's share with no limitation, regardless of the reason for any default. For Priest Rapids and Wanapum, PGE would be allocated up to a cumulative maximum that would not adversely affect the tax-exempt status of any of the public utility district's outstanding debt for the portion of the project that benefits tax-exempt purchasers.

Natural gas—PGE has contracts for the purchase and transportation of natural gas from domestic and Canadian sources for its natural gas-fired generating facilities.

Coal and transportation—PGE has coal and related rail transportation agreements with take-or-pay provisions related to Boardman that expire in December 2020. The Company also has a coal agreement with take-or-pay provisions related to Colstrip that expires in December 2025.

Guarantees

PGE enters into financial agreements and power and natural gas purchase and sale agreements that include indemnification provisions relating to certain claims or liabilities that may arise relating to the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. PGE periodically evaluates the likelihood of incurring costs under such indemnities based on the Company's historical experience and the evaluation of the specific indemnities. As of December 31, 2019, management believes the likelihood is remote that PGE would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnities. The Company has not recorded any liability on the consolidated balance sheets with respect to these indemnities.

NOTE 17: LEASES

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

Operating leases reflect lease expense on a straight-line basis, while finance leases result in the separate presentation of interest expense on the lease liability and amortization expense of the ROU asset. Any material differences between expense recognition and timing of payments is deferred as a regulatory asset or liability in order to match what is being recovered in customer prices for ratemaking purposes.

PGE does not record leases with a term of 12-months or less in the consolidated balance sheets. Total short-term lease costs as of December 31, 2019 are immaterial. PGE has lease agreements with lease and non-lease components, which are accounted for separately.

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

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

	2019
Operating lease cost	$ 7
Finance lease cost:	
Amortization of right-of-use assets	$ 3
Interest on lease liabilities	6
Total finance lease cost	$ 9
Variable lease cost	$ 19

Supplemental information related to amounts and presentation of leases in the consolidated balance sheets is presented below (in millions):

	Balance Sheet Classification	December 31, 2019
Operating Leases:		
Operating lease right-of-use assets	Other noncurrent assets	$ 51
Current liabilities	Accrued expenses and other current liabilities	$ 8
Noncurrent liabilities	Other noncurrent liabilities	43
Total operating lease liabilities		$ 51
Finance Leases:		
Finance lease right-of-use assets	Electric utility plant, net	$ 150
Current liabilities	Current portion of finance lease obligations	$ 16
Noncurrent liabilities	Finance lease obligations, net of current portion	135
Total finance lease liabilities		$ 151

Lease term and discount rates were as follows:

	December 31, 2019
Weighted Average Remaining Lease Term	
Operating leases	24 years
Finance leases	29 years
Weighted Average Discount Rate	
Operating leases	3.5%
Finance leases	7.3%

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

As of December 31, 2019, maturities of lease liabilities were as follows (in millions):

	Operating Leases	Finance Leases
2020	$ 8	$ 16
2021	8	16
2022	8	16
2023	8	14
2024	7	14
Thereafter	46	235
Total lease payments	85	311
Less imputed interest	(34)	(160)
Total	$ 51	$ 151

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

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

2018 Lease Obligations

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

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

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

As of December 31, 2018, a capital lease asset of $57 million was reflected within Electric utility plant and accumulated amortization of such assets of $8 million was reflected within Accumulated depreciation and amortization in the consolidated balance sheets. The present value of the future minimum lease payments due under the agreement included $2 million within Accrued expenses and other current liabilities and $47 million in Other noncurrent liabilities on the consolidated balance sheets. For ratemaking purposes capital leases are treated as operating leases; therefore, in accordance with the accounting rules for regulated operations, the amortization of the leased asset is based on the rental payments recovered from customers. Amortization of the leased asset of $3 million and interest expense of $4 million was recorded to Purchased power and fuel expense in the consolidated statements of income through December 31, 2018. Pursuant to the adoption of the new lease accounting standard, Topic 842, PGE derecognized the capital lease obligation and related capital lease asset as it no longer met the definition of a lease.

Build-to-suit—PGE entered into a 30-year lease agreement with a local natural gas company, NW Natural, to expand their natural gas storage facilities, including the development of an underground storage reservoir and construction of a new compressor station and 13-miles of pipeline, which are collectively designed to provide no-notice storage and transportation services to PW1, PW2, and Beaver. Construction of the expansion project was completed in the second quarter of 2019 at a cost of $149 million. Due to the level of PGE's involvement during the construction period, the Company was deemed to be the owner of the assets for accounting purposes during the construction period. As a result, PGE recorded $131 million to Construction work-in-progress within Electric utility plant, net and a corresponding liability for the same amount to Other noncurrent liabilities in the consolidated balance sheets as of December 31, 2018. Pursuant to the adoption of the new lease accounting standard, Topic 842, PGE derecognized the build-to-suit assets and liabilities as they are no longer considered to meet the build-to-suit criteria under the new standard. For additional information regarding the new lease accounting standard, see Note 2, Summary of Significant Accounting Policies.

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

Operating leases—PGE has various operating leases associated with leases of land, support facilities, and power purchase agreements that rely on identified plant that expire in various years, extending through 2096. Rent expense was $7 million in 2018. Contingent rents related to power purchase agreements was $14 million in 2018. Sublease income was $4 million in 2018.

NOTE 18: JOINTLY-OWNED PLANT

As of December 31, 2019, PGE had the following investments in jointly-owned plant (dollars in millions):

	PGE Share	In-service Date	Plant In-service	Accumulated Depreciation*	Construction Work In Progress
Boardman	90.00%	1980	$ 517	$ 478	$ —
Colstrip	20.00	1986	550	375	14
Pelton/Round Butte	66.67	1958 / 1964	265	78	6
Total			$ 1,332	$ 931	$ 20

* Excludes AROs and accumulated asset retirement removal costs.

Under the respective joint operating agreements for the generating facilities, each participating owner is responsible for financing its share of capital and operating expenses. PGE's proportionate share of direct operating and maintenance expenses of the facilities is included in the corresponding operating and maintenance expense categories in the consolidated statements of income.

NOTE 19: CONTINGENCIES

PGE is subject to legal, regulatory, and environmental proceedings, investigations, and claims that arise from time to time in the ordinary course of its business. Contingencies are evaluated using the best information available at the time the consolidated financial statements are prepared. Legal costs incurred in connection with loss contingencies are expensed as incurred. The Company may seek regulatory recovery of certain costs that are incurred in connection with such matters, although there can be no assurance that such recovery would be granted.

Loss contingencies are accrued, and disclosed if material, when it is probable that an asset has been impaired, or a liability incurred, as of the financial statement date and the amount of the loss can be reasonably estimated. If a reasonable estimate of probable loss cannot be determined, a range of loss may be established, in which case the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate.

A loss contingency will also be disclosed when it is reasonably possible that an asset has been impaired, or a liability incurred, if the estimate or range of potential loss is material. If a probable or reasonably possible loss cannot be reasonably estimated, then the Company: i) discloses an estimate of such loss or the range of such loss, if the Company is able to determine such an estimate; or ii) discloses that an estimate cannot be made and the reasons.

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

PGE evaluates, on a quarterly basis, developments in such matters that could affect the amount of any accrual, as well as the likelihood of developments that would make a loss contingency both probable and reasonably estimable. The assessment as to whether a loss is probable or reasonably possible, and as to whether such loss or a range of such loss is estimable, often involves a series of complex judgments about future events. Management is often unable to estimate a reasonably possible loss, or a range of loss, particularly in cases in which: i) the damages sought are indeterminate or the basis for the damages claimed is not clear; ii) the proceedings are in the early stages; iii) discovery is not complete; iv) the matters involve novel or unsettled legal theories; v) significant facts are in dispute; vi) a large number of parties are represented (including circumstances in which it is uncertain how liability, if any, would be shared among multiple defendants); or vii) a wide range of potential outcomes exist. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including any possible loss, fine, penalty, or business impact.

EPA Investigation of Portland Harbor

An investigation by the United States Environmental Protection Agency (EPA) of a segment of the Willamette River known as Portland Harbor that began in 1997 revealed significant contamination of river sediments. The EPA subsequently included Portland Harbor on the National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act as a federal Superfund site. PGE was included among the Potentially Responsible Parties (PRPs) as it has historically owned or operated property near the river.

In 2008, the EPA requested information from various parties, including PGE, concerning additional properties in or near the original segment of the river under investigation, as well as several miles beyond. Subsequently, the EPA has listed additional PRPs, which now number over one hundred.

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

The EPA finalized the feasibility study, along with the remedial investigation, and the results provided the framework for the EPA to determine a clean-up remedy for Portland Harbor that was documented in a Record of Decision (ROD) issued in 2017. The ROD outlined the EPA's selected remediation plan for clean-up of the Portland Harbor site, which has an undiscounted estimated total cost of $1.7 billion, comprised of $1.2 billion related to remediation construction costs and $0.5 billion related to long-term operation and maintenance costs. Remediation construction costs were estimated to be incurred over a 13-year period, with long-term operation and maintenance costs estimated to be incurred over a 30-year period from the start of construction. The EPA acknowledged the estimated costs are based on data that was outdated and that pre-remedial design sampling was necessary to gather updated baseline data to better refine the remedial design and estimated cost. A small group of PRPs performed pre-remedial design sampling to update baseline data and submitted the data in an updated evaluation report to the EPA for review. The evaluation report concluded that the conditions of the Portland Harbor Superfund site have improved substantially over the past ten years. In response, the EPA indicated that while it would use the data to inform implementation of the ROD, the EPA's conclusions remained materially unchanged. EPA is currently seeking parties to sign up to perform remedial design.

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

In cases in which injuries to natural resources have occurred as a result of releases of hazardous substances, federal and state natural resource trustees may seek to recover for damages at such sites, which are referred to as Natural Resource Damages (NRD). The EPA does not manage NRD assessment activities but does provide claims information and coordination support to the NRD trustees. NRD assessment activities are typically conducted by a Council made up of the trustee entities for the site. The Portland Harbor NRD trustees consist of the National Oceanic and Atmospheric Administration, the U.S. Fish and Wildlife Service, the state of Oregon, the Confederated Tribes of the Grand Ronde Community of Oregon, the Confederated Tribes of Siletz Indians, the Confederated Tribes of the Umatilla Indian Reservation, the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS), and the Nez Perce Tribe.

The NRD trustees may seek to negotiate legal settlements or take other legal actions against the parties responsible for the damages. Funds from such settlements must be used to restore injured resources and may also compensate the trustees for costs incurred in assessing the damages. The Company believes that PGE's portion of NRD liabilities related to Portland Harbor will not have a material impact on its results of operations, financial position, or cash flows.

The impact of such costs to the Company's results of operations is mitigated by the Portland Harbor Environmental Remediation Account (PHERA) mechanism. As approved by the OPUC in 2017, the PHERA allows the Company to defer and recover incurred environmental expenditures related to the Portland Harbor Superfund Site through a combination of third-party proceeds, such as insurance recoveries, and if necessary, through customer prices. The mechanism established annual prudency reviews of environmental expenditures and third-party proceeds. Annual expenditures in excess of $6 million, excluding expenses related to contingent liabilities, are subject to an annual earnings test and would be ineligible for recovery to the extent PGE's actual regulated return on equity exceeds its return on equity as authorized by the OPUC in PGE's most recent general rate case. 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.

Trojan Investment Recovery Class Actions

In 1993, PGE closed the Trojan nuclear power plant (Trojan) and sought full recovery of, and a rate of return on, its Trojan costs in a general rate case filing with the OPUC. In 1995, the OPUC issued a general rate order that granted the Company recovery of, and a rate of return on, 87% of its remaining investment in Trojan.

Numerous challenges and appeals were subsequently filed in various state courts on the issue of the OPUC's authority under Oregon law to grant recovery of, and a return on, the Trojan investment. In 2007, following several appeals by various parties, the Oregon Court of Appeals issued an opinion that remanded the matter to the OPUC for reconsideration.

In 2003, in two separate proceedings, lawsuits were filed against PGE on behalf of two classes of electric service customers: i) Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company, Marion County Circuit Court (Circuit Court); and ii) Morgan v. Portland General Electric Company, Marion County Circuit Court. The class action lawsuits seek damages totaling $260 million, plus interest, as a result of the Company's inclusion, in prices charged to customers, of a return on its investment in Trojan.

In 2006, the Oregon Supreme Court (OSC) issued a ruling ordering the abatement of the class action proceedings. The OSC concluded that the OPUC had primary jurisdiction to determine what, if any, remedy could be offered to PGE customers, through price reductions or refunds, for any amount of return on the Trojan investment that the Company collected in prices.

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

In 2015, based on a motion filed by PGE, the Marion County Circuit Court lifted the abatement on the class action proceedings and heard oral argument on the Company's motion for Summary Judgment. In 2016, the Circuit Court entered a general judgment that granted the Company's motion for Summary Judgment and dismissed all claims by the plaintiffs. The plaintiffs subsequently appealed the Circuit Court dismissal to the Court of Appeals for the state of Oregon.

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

PGE believes that the 2014 OSC decision, the decisions of the Circuit Court and the Court of Appeals that followed have reduced the risk of any loss to the Company beyond the amounts previously recorded and refunds discussed above. However, because the class actions remain subject to a potential petition for review to the OSC, management believes that it is reasonably possible that such a loss to the Company could result. As these matters involve unsettled legal theories and have a broad range of potential outcomes, sufficient information is currently not available to determine the amount of any such loss.

Deschutes River Alliance Clean Water Act Claims

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

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

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

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

In October 2018, DRA filed an appeal, and PGE and CTWS filed cross-appeals, to the Ninth Circuit Court of Appeals. In December 2019, the Court of Appeals closed the case and vacated the briefing schedule, pending ongoing discussions among the parties.

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

Other Matters

PGE is subject to other regulatory, environmental, and legal proceedings, investigations, and claims that arise from time to time in the ordinary course of business, which may result in judgments against the Company. Although management currently believes that resolution of such matters, individually and in the aggregate, will not have a material impact on its financial position, results of operations, or cash flows, these matters are subject to inherent uncertainties, and management's view of these matters may change in the future.

QUARTERLY FINANCIAL DATA

(Unaudited)

	Quarter Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share amounts)			
2019				
Total revenues	$ 573	$ 460	$ 542	$ 548
Income from operations	111	57	88	97
Net income	73	25	55	61
Earnings per share:*				
Basic	0.82	0.28	0.61	0.68
Diluted	0.82	0.28	0.61	0.68
2018				
Total revenues	$ 493	$ 449	$ 525	$ 524
Income from operations	100	80	91	75
Net income	64	46	53	49
Earnings per share:*				
Basic	0.72	0.51	0.59	0.55
Diluted	0.72	0.51	0.59	0.55

* Earnings per share are calculated independently for each period presented. Accordingly, the sum of the quarterly earnings per share amounts may not equal the total for the year.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. CONTROLS AND PROCEDURES.

(a) Disclosure Controls and Procedures

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and the Chief Financial Officer, has evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the period covered by this report pursuant to Rule 13a-15(b) under the Exchange Act. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of such period, the Company's disclosure controls and procedures are effective.

(b) Management's Annual Report on Internal Control over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act). The Company's internal control over financial reporting is a process designed by, or under the supervision of, the Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company's internal control over financial reporting as of the end of the period covered by this report pursuant to Rule 13a-15(c) under the Exchange Act. Management's assessment was based on the framework established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management has concluded that, as of December 31, 2019, the Company's internal control over financial reporting is effective.

The Company's internal control over financial reporting, as of December 31, 2019, has been audited by Deloitte & Touche LLP, the independent registered public accounting firm who audits the Company's consolidated financial statements, as stated in their report included in Item 8.—"Financial Statements and Supplementary Data," which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting, as of December 31, 2019.

(c) Changes in Internal Control over Financial Reporting

There have not been any changes in the Company's internal control over financial reporting during the fourth quarter of 2019 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Certain information required by Item 10 is incorporated herein by reference to the relevant information under the captions “Delinquent Section 16(a) Reports,” “Corporate Governance,” and “Item 1: Election of Directors” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 22, 2020. Information regarding executive officers of Portland General Electric Company may be found in Part I, Item 1. Business of this Annual Report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION.

The information required by Item 11 is incorporated herein by reference to the relevant information under the captions “Corporate Governance—Director Compensation,” “Corporate Governance—Compensation Committee Interlocks,” “Compensation and Human Resources Committee Report,” “Compensation Discussion and Analysis,” and “Executive Compensation Tables” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 22, 2020.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information required by Item 12 is incorporated herein by reference to the relevant information under the captions “Security Ownership of Certain Beneficial Owners, Directors and Executive Officers,” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 22, 2020.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required by Item 13 is incorporated herein by reference to the relevant information under the caption “Corporate Governance” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 22, 2020.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by Item 14 is incorporated herein by reference to the relevant information under the captions “Principal Accountant Fees and Services” and “Pre-Approval Policy for Independent Auditor Services” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 22, 2020.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a) Financial Statements and Schedules

The financial statements are set forth under Item 8 of this Annual Report on Form 10-K. Financial statement schedules have been omitted since they are either not required, not applicable, or the information is otherwise included.

(b) Exhibit Listing

Exhibit Number	Description
(3)	**Articles of Incorporation and Bylaws**
3.1*	Third Amended and Restated Articles of Incorporation of Portland General Electric Company (Form 8-K filed May 9, 2014, Exhibit 3.1).
3.2*	Eleventh Amended and Restated Bylaws of Portland General Electric Company (Form 10-K filed February 15, 2019, Exhibit 3.2).
(4)	**Instruments defining the rights of security holders, including indentures**
4.1*	Portland General Electric Company Indenture of Mortgage and Deed of Trust dated July 1, 1945 (Form 8, Amendment No. 1 dated June 14, 1965) (File No. 001-05532-99).
4.2*	Fortieth Supplemental Indenture dated October 1, 1990 (Form 10-K for the year ended December 31, 1990, Exhibit 4) (File No. 001-05532-99).
4.3*	Sixty-second Supplemental Indenture dated April 1, 2009 (Form 8-K filed April 16, 2009, Exhibit 4.1) (File No. 001-05532-99).
4.4*	Seventy-third Supplemental Indenture dated August 1, 2017, between the Company and Wells Fargo Bank, National Association, as Trustee (Form 8-K filed August 3, 2017, Exhibit 4.1).
4.5*	Seventy-fifth Supplemental Indenture, dated April 1, 2019, between the Company and Wells Fargo Bank, National Association, as trustee (Form 8-K filed April 15, 2019, Exhibit 4.1).
4.6	Description of Securities
(10)	**Material Contracts**
10.1*	Amended and Restated Credit Agreement dated March 6, 2015 between Portland General Electric Company and Wells Fargo Bank, National Association, as Administrative Agent, Bank of America, N.A., Barclays Bank PLC, JPMorgan Chase Bank, N.A. and U.S. Bank National Association (Form 10-Q filed April 27, 2015, Exhibit 10.1).
10.2*	First Amendment to Credit Agreement, dated February 21, 2017 among Portland General Electric Company, Lenders, and Wells Fargo Bank, National Association, as administrative agent for the Lenders (Form 10-K filed February 16, 2018, Exhibit 10.2).
10.3*	Second Amendment to Credit Agreement, dated as of January 16, 2019 among Portland General Electric Company, Lenders, and Wells Fargo Bank, National Association, as administrative agent for the Lenders (Form 10-K filed February 15, 2019, Exhibit 10.3).
10.4*	Consent Agreement, dated December 6, 2017 among Portland General Electric Company, Lenders, and Wells Fargo Bank, National Association, as administrative agent for the Lenders (Form 10-K filed February 16, 2018, Exhibit 10.3).
10.5*	Portland General Electric Company Severance Pay Plan for Executive Employees, as amended and restated effective February 14, 2017 (Form 10-K filed February 17, 2017, Exhibit 10.2). +
10.6*	Portland General Electric Company Outplacement Assistance Plan dated June 15, 2005 (Form 8-K filed June 20, 2005, Exhibit 10.2) (File No. 001-05532-99). +
10.7*	Portland General Electric Company 2005 Management Deferred Compensation Plan dated January 1, 2005 (Form 10-K filed March 11, 2005, Exhibit 10.18) (File No. 001-05532-99). +
10.8*	Portland General Electric Company Management Deferred Compensation Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.1) (File No. 001-05532-99). +

Exhibit Number	Description
10.9*	Portland General Electric Company Supplemental Executive Retirement Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.2) (File No. 001-05532-99). +
10.10*	Portland General Electric Company Senior Officers' Life Insurance Benefit Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.3) (File No. 001-05532-99). +
10.11*	Portland General Electric Company Umbrella Trust for Management dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.4) (File No. 001-05532-99). +
10.12*	Portland General Electric Company Stock Incentive Plan, As Amended and Restated Effective February 13, 2018. (Form 10-Q filed April 27, 2018, Exhibit 10.1) (File No. 001-055532-99). +
10.13*	Portland General Electric Company 2006 Annual Cash Incentive Master Plan (Form 8-K filed March 17, 2006, Exhibit 10.1) (File No. 001-05532-99). +
10.14*	Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan (Form 8-K filed May 17, 2006, Exhibit 10.1) (File No. 001-05532-99). +
10.15*	Portland General Electric Company 2008 Annual Cash Incentive Master Plan for Executive Officers (Form 8-K filed February 26, 2008, Exhibit 10.1) (File No. 001-05532-99). +
10.16*	Form of Portland General Electric Company Agreement Concerning Indemnification and Related Matters (Form 8-K filed December 24, 2009, Exhibit 10.1) (File No. 001-05532-99). +
10.17*	Form of Portland General Electric Company Agreement Concerning Indemnification and Related Matters for Officers and Key Employees (Form 8-K filed February 19, 2010, Exhibit 10.1) (File No. 001-05532-99). +
10.18	Form of Directors' Restricted Stock Unit Agreement +
10.19	Form of Officers' and Key Employees' Performance Stock Unit Agreement +
10.20	Form of Officers' and Key Employees' Restricted Stock Unit Agreement +
10.21	Separation Agreement dated September 27, 2019 by and between William Nicholson and Portland General Electric Company. +
(23)	**Consents of Experts and Counsel**
23.1	Consent of Independent Registered Public Accounting Firm Deloitte & Touche LLP.
(31)	**Rule 13a-14(a)/15d-14(a) Certifications**
31.1	Certification of Chief Executive Officer.
31.2	Certification of Chief Financial Officer.
(32)	**Section 1350 Certifications**
32.1	Certifications of Chief Executive Officer and Chief Financial Officer.
(101)	**Interactive Data File**
101.INS	XBRL Instance Document. The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
104	Cover page information from Portland General Electric Company's Annual Report on Form 10-K filed February 14, 2020, formatted in iXBRL (Inline Extensible Business Reporting Language).

* Incorporated by reference as indicated.

\+ Indicates a management contract or compensatory plan or arrangement.

Certain instruments defining the rights of holders of other long-term debt of PGE are omitted pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K because the total amount of securities authorized under each such omitted instrument does not exceed 10% of the total consolidated assets of the Company and its subsidiaries. PGE hereby agrees to furnish a copy of any such instrument to the SEC upon request.

Upon written request to Investor Relations, Portland General Electric Company, 121 S.W. Salmon Street, Portland, Oregon 97204, the Company will furnish shareholders with a copy of any Exhibit upon payment of reasonable fees for reproduction costs incurred in furnishing requested Exhibits.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on February 13, 2020.

PORTLAND GENERAL ELECTRIC COMPANY

By: /s/ MARIA M. POPE

Maria M. Pope

President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on February 13, 2020.

Signature	Title
/s/ MARIA M. POPE **Maria M. Pope**	*President, Chief Executive Officer, and Director* (principal executive officer)
/s/ JAMES F. LOBDELL **James F. Lobdell**	*Senior Vice President of Finance, Chief Financial Officer, and Treasurer* (principal financial and accounting officer)
/s/ JOHN W. BALLANTINE **John W. Ballantine**	*Director*
/s/ RODNEY L. BROWN, JR. **Rodney L. Brown, Jr.**	*Director*
/s/ JACK E. DAVIS **Jack E. Davis**	*Director*
/s/ KIRBY A. DYESS **Kirby A. Dyess**	*Director*
/s/ MARK B. GANZ **Mark B. Ganz**	*Director*
/s/ MARIE OH HUBER **Marie Oh Huber**	*Director*
/s/ KATHRYN J. JACKSON **Kathryn J. Jackson**	*Director*
/s/ MICHAEL H. MILLEGAN **Michael H. Millegan**	*Director*
/s/ NEIL J. NELSON **Neil J. Nelson**	*Director*
/s/ M. LEE PELTON **M. Lee Pelton**	*Director*
/s/ CHARLES W. SHIVERY **Charles W. Shivery**	*Director*

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-232976 on Form S-3 and Registration Statements Nos. 333-135726, 333-142694, and 333-158059 on Forms S-8 of our report dated February 13, 2020, relating to the consolidated financial statements of Portland General Electric Company and subsidiaries, and the effectiveness of Portland General Electric Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Portland General Electric Company for the year ended December 31, 2019.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 13, 2020

EXHIBIT 31.1

CERTIFICATION

I, Maria M. Pope, certify that:

1. I have reviewed this Annual Report on Form 10-K of Portland General Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2020

/s/ MARIA M. POPE
Maria M. Pope
President and
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, James F. Lobdell, certify that:

1. I have reviewed this Annual Report on Form 10-K of Portland General Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2020

/s/ JAMES F. LOBDELL
James F. Lobdell
Senior Vice President of Finance, Chief Financial Officer, and Treasurer

EXHIBIT 32.1

**CERTIFICATIONS PURSUANT TO
18 U.S.C. SECTION 1350, AS ADOPTED
PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

We, Maria M. Pope, President and Chief Executive Officer, and James F. Lobdell, Senior Vice President of Finance, Chief Financial Officer and Treasurer, of Portland General Electric Company (the "Company"), hereby certify that the Company's Annual Report on Form 10-K for the year ended December 31, 2019, as filed with the Securities and Exchange Commission on February 14, 2020 pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the "Report"), fully complies with the requirements of that section.

We further certify that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ MARIA M. POPE	/s/ JAMES F. LOBDELL
Maria M. Pope	James F. Lobdell
President and Chief Executive Officer	*Senior Vice President of Finance, Chief Financial Officer and Treasurer*
Date: February 13, 2020	Date: February 13, 2020

Corporate information

BOARD OF DIRECTORS

Jack E. Davis
Chair of the Board of Directors,
Portland General Electric;
Retired Chief Executive Officer,
Arizona Public Service Company

Maria M. Pope
President and Chief Executive Officer,
Portland General Electric

John W. Ballantine
Retired Executive Vice President and
Chief Risk Management Officer,
First Chicago NBD Corporation

Rodney L. Brown Jr.
Founding Partner,
Cascadia Law Group PLLC

Kirby A. Dyess
Principal,
Austin Capital Management LLC

Mark B. Ganz
President and Chief Executive Officer,
Cambia Health Solutions, Inc.

Marie Oh Huber
Senior Vice President,
General Counsel and Secretary,
eBay, Inc.

Kathryn J. Jackson
Director of Energy and Technology
Consulting, KeySource, Inc.

Michael H. Millegan
Founder and Chief Executive Officer,
Millegan Advisory Group 3 LLC

Neil J. Nelson
President, Siltronic Corporation

M. Lee Pelton
President, Emerson College

Charles W. Shivery
Retired Chairman, President and Chief
Executive Officer, Northeast Utilities

CORPORATE OFFICERS

Maria M. Pope
President and Chief Executive Officer

James F. Lobdell
Senior Vice President, Finance,
Chief Financial Officer and Treasurer

Larry N. Bekkedahl
Vice President,
Grid Architecture,
Integration and Systems Operations

Bradley Y. Jenkins
Vice President,
Utility Operations

Lisa A. Kaner
Vice President,
General Counsel and
Corporate Compliance Officer

John T. Kochavatr
Vice President,
Information Technology and
Chief Information Officer

John C. McFarland
Vice President,
Customer Solutions,
Chief Customer Officer

Anne F. Mersereau
Vice President,
Human Resources,
Diversity, Equity and Inclusion

W. David Robertson
Vice President,
Public Policy

Kristin A. Stathis
Vice President,
Operations Services

INVESTOR INFORMATION

Corporate headquarters
Portland General Electric Company
121 SW Salmon St.
Portland, OR 97204
503-464-8000
investors.portlandgeneral.com

Transfer agent
American Stock
Transfer & Trust Company
6201 15th Ave.
Brooklyn, NY 11219
866-621-2788

Independent auditors
Deloitte & Touche LLP
3900 U.S. Bancorp Tower
Portland, OR 97204
503-222-1341

Form 10-K
A copy of the company's 2019 Annual Report on Form 10-K will be furnished, without charge, upon written request made to:

Christopher Liddle
Director of Investor
Relations and Treasury
121 SW Salmon St.
1WTC0506
Portland, OR 97204

You may also obtain a copy of the Form 10-K by calling Investor Relations at 503-464-8586 or by downloading a copy from investors.portlandgeneral.com.

Market information
Portland General Electric Company stock trades on the New York Stock Exchange under the ticker symbol POR.

To vote online visit:
investors.portlandgeneral.com

2019 highlights

We are committed to a clean energy future and to transparent, consistent reporting about environmental, social and governance achievements for the benefit of customers and the financial sector. We have adopted the Edison Electric Institute's ESG reporting framework. Our 2018 EEI ESG report is available on investors.portlandgeneral.com and is updated annually.

ADVANCING A SUSTAINABLE ENVIRONMENT

First

Major renewable energy facility in North America, the Wheatridge Renewable Energy Facility will combine 300 MW of wind generation, 50 MW of solar generation and 30 MW of battery storage.

150 MWa

Of additional renewable resources proposed in our 2019 Integrated Resource Plan, which also includes pursuing a similar amount of energy efficiency; strengthening partnerships with customers to balance the grid through flexible load programs; and pursuit of new clean technologies, like energy storage, to support grid reliability.

Completed

Our fleet decarbonization study and are progressing plans to electrify almost 1,100 vehicles, providing lessons and processes for customers to follow.

Seven

Electric Avenues now operating in our service area, expanding our network of charging infrastructure.

First

All-electric bus line launched in partnership with TriMet, the state's largest transit provider. We are also partnering in planning charging infrastructure for broader bus electrification and a 20-year electric fuel plan.

First

Electric bus program launched in Oregon to help school districts electrify their buses.

$200 million

Investment in an Integrated Operations Center with enhanced technology and resilience against seismic, cyber and physical security risks, to centralize key operations and functions.

CARING FOR OUR COMMUNITIES

$4.7 million

Donated to support local schools and nonprofits, by PGE, employees, retirees and the PGE Foundation.

60

Scholarships and 55 summer internships facilitated for Oregon students.

736

Nonprofits around Oregon strengthened our community with help from 1,102 PGE employee and retiree volunteers during 2019.

71,779

Students educated about electric safety and energy in classrooms and safety fairs.

GOVERNANCE

First

Year with an Energy Supply Decarbonization metric tied to long-term incentives for executives which align with our carbon reduction goals.

Second

Year of inclusion in Bloomberg's Gender-Equality Index for our company-wide commitment to transparency and advancing women's equality in policies, workforce demographics and community engagement and support.

COVER PHOTO

Downtown Portland, Oregon

INSIDE SHAREHOLDER LETTER

Maria Pope, PGE President and Chief Executive Officer

INSIDE 2019 HIGHLIGHTS (LEFT)

Our Biglow Canyon Wind Farm

INSIDE 2019 HIGHLIGHTS (RIGHT)

PGE employees John Harvey, Frank Viviano, Caitlin Horsely, John Whalen, Craig Tylenda and PGE families join SOLVE volunteers for a Fall cleanup

Maria Pope with Bloomberg Chair Peter Grauer and Carolyn Tastad of Proctor & Gamble at the 2019 Bloomberg Equality Summit

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

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

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Portland General Electric Company	End of 2019/Q4

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

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/forms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

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

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ____________ , we have also reviewed schedules ___________________of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.asp#3Q-gas .

IV. When to Submit:

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

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

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

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

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

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and” firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Portland General Electric Company		02 Year/Period of Report End of 2019/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 Jardon Jaramillo		06 Title of Contact Person Controller & Asst. Treasurer
07 Address of Contact Person *(Street, City, State, Zip Code)* 121 SW Salmon Street, Portland, Oregon, 97204		
08 Telephone of Contact Person, *Including Area Code* (503) 464-7051	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* / /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name James F. Lobdell	03 Signature James F. Lobdell	04 Date Signed *(Mo, Da, Yr)* 03/27/2020
02 Title SVP of Finance, CFO and Treasurer		

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	Not applicable
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	Not applicable
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	None
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	None
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	None
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

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

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LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

GENERAL INFORMATION

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

Jardon Jaramillo
Controller and Assistant Treasurer
121 SW Salmon Street
Portland, OR 97204

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

Oregon - Incorporated July 25, 1930

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

Property of respondent was not so held during the year.

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

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

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

CONTROL OVER RESPONDENT

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	121 SW Salmon Street Corporation	Company has purchased the	100	
2		headquarters complex in		
3		Portland, Oregon and leases		
4		the complex to the Respondent		
5				
6	World Trade Center Northwest Corporation	Company is the holder of the	100	
7	(A wholly-owned subsidiary of 121 SW Salmon	World Trade Center Franchise		
8	Street Corporation)			
9				
10	Salmon Springs Hospitality Group	Company provides food	100	
11		catering services		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President and Chief Executive Officer	Maria M. Pope	830,769
2			
3	Senior Vice President of Finance, Chief Financial	James F. Lobdell	489,535
4	Officer and Treasurer		
5			
6	Vice President, General Counsel and Corporate	Lisa A. Kaner	377,596
7	Compliance Officer		
8			
9	Vice President, Utility Technical Services	William O. Nicholson	332,144
10			
11	Vice President, Public Policy	W. David Robertson	328,482
12			
13	Vice President, Chief Customer Officer	John McFarland	208,846
14			
15	Vice President, Utility Operations	Bradley Y. Jenkins	335,962
16			
17	Vice President, Grid Architecture, Integration &	Larry N. Bekkedahl	331,664
18	Systems Operations		
19			
20	Vice President, Information Technology and Chief	John Kochavatr	338,077
21	Information Officer		
22			
23	Vice President, Operations Services	Kristin A. Stathis	295,644
24			
25	Vice President, Human Resources, Diversity,	Anne E. Mersereau	303,886
26	Equity & Inclusion		
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

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

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

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

Retired from company effective December 31, 2019.

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

Appointed to position effective April 19, 2019.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	John W. Ballantine	Palm Beach, Florida
2	Retired Executive Vice President, First Chicago NBD Corp.	
3		
4	Rodney L. Brown, Jr.	Seattle, Washington
5	Founding Partner, Cascadia Law Group PLLC	
6		
7	Jack E. Davis	Scottsdale, Arizona
8	Chair of the Board, Portland General Electric	
9	Retired Chief Executtive Officer, Arizona Public Service Co.	
10		
11	David A. Dietzler	Lake Oswego, Oregon
12	Retired Partner, KPMG LLP	
13		
14	Kirby A. Dyess	Beaverton, Oregon
15	Principal, Austin Capital Management LLC	
16		
17	Mark B. Ganz	Portland, Oregon
18	President and Chief Executive Officer,	
19	Cambia Health Solutions, Inc.	
20		
21	Kathryn J. Jackson	Pittsburg, Pennsylvania
22	Director, Energy & Technology Consulting, KeySource, Inc.	
23		
24	Neil J. Nelson	Portland, Oregon
25	President and Chief Executive Officer, Siltronic Corp.	
26		
27	M. Lee Pelton	Boston, Massachusetts
28	President, Emerson College	
29		
30	Maria M. Pope	Portland, Oregon
31	President and Chief Executive Officer,	
32	Portland General Electric	
33		
34	Charles W. Shivery	Longboat Key, Florida
35	Retired President and Chief Executive Officer,	
36	Northeast Utilities	
37		
38	Marie Oh Huber	San Jose, California
39	Sr. VP General Counsel and Secretary eBay Inc	
40		
41	Michael H. Millegan	Kirkland, Washington
42	Millegan Advisory Group 3 LLC	
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Name of Respondent Portland General Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2019/Q4

FOOTNOTE DATA

Schedule Page: 105 Line No.: 11 Column: a

Retired from position on April 24, 2019.

Schedule Page: 105 Line No.: 38 Column: a

Appointed to position effective May 24, 2019.

Schedule Page: 105 Line No.: 41 Column: a

Appointed to position effective January 1, 2019.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

Does the respondent have formula rates? [ ] Yes [X] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

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

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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 Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

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

Name of Respondent Portland General Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2019/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

1. None

2. None

3. None

4. None

5. None

6. Pursuant to PGE's application, the FERC, on January 16, 2020, issued an order in Docket No. ES20-7-000 that authorizes the Company to issue up to $900 million of short-term debt through February 7, 2022. The authorization provides that if utility assets financed by unsecured debt are divested, then a proportionate share of the unsecured debt must also be divested.

As of December 31, 2019, PGE had a $500 million revolving credit facility scheduled to expire in November 2023. The facility allows for unlimited extension requests, provided that lenders with a pro-rata share of more than 50% approve the extension request. The revolving credit facility supplements operating cash flows and provides a primary source of liquidity. Pursuant to the terms of the agreement, the revolving credit facility may be used as backup for commercial paper borrowings, to permit the issuance of standby letters of credit, and for general corporate purposes. PGE may borrow for one, two, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the credit facility.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days, limited to the unused amount of credit under the revolving credit facility. PGE classifies any borrowings under the revolving credit facility and outstanding commercial paper as Notes Payable on the Comparative Balance Sheet.

Under the revolving credit facility, as of December 31, 2019, PGE had no borrowings or commercial paper outstanding. As a result, the aggregate unused available credit capacity under the revolving credit facility was $500 million.

In addition, PGE has four letter of credit facilities under which the Company can request letters of credit for original terms not to exceed one year. These facilities provide for a total capacity of $220 million. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these facilities, letters of credit for a total of $55 million were outstanding, as of December 31, 2019.

During 2019, PGE issued a total of $470 million of FMBs with $200 million issued in April at an interest rate of 4.3% maturing in 2049 and $270 million at an interest rate of 3.34% issued in two tranches. The first tranche, $110 million with a maturity in 2049, was issued in October 2019 and the second tranche, $160 million with a maturity in 2050, was issued in November 2019. A portion of the proceeds was used to repay a total of $350 million in FMBs in 2019.

PGE enters into financial agreements and power and natural gas purchase and sale agreements that include indemnification provisions relating to certain claims or liabilities that may arise relating to the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. PGE periodically evaluates the likelihood of incurring costs under such indemnities based on the Company's historical experience and the evaluation of the specific indemnities. As of December 31, 2019, 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

Name of Respondent Portland General Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2019/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

9. Legal Proceedings:

Trojan Investment Recovery Class Actions

In 1993, PGE closed the Trojan nuclear power plant (Trojan) and sought full recovery of, and a rate of return on, its Trojan costs in a general rate case filing with the OPUC. In 1995, the OPUC issued a general rate order that granted the Company recovery of, and a rate of return on, 87% of its remaining investment in Trojan.

Numerous challenges and appeals were subsequently filed in various state courts on the issue of the OPUC's authority under Oregon law to grant recovery of, and a return on, the Trojan investment. In 2007, following several appeals by various parties, the Oregon Court of Appeals issued an opinion that remanded the matter to the OPUC for reconsideration.

In 2003, in two separate proceedings, lawsuits were filed against PGE on behalf of two classes of electric service customers: i) Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company, Marion County Circuit Court (Circuit Court); and ii) Morgan v. Portland General Electric Company, Marion County Circuit Court. The class action lawsuits seek damages totaling $260 million, plus interest, as a result of the Company's inclusion, in prices charged to customers, of a return on its investment in Trojan.

In 2006, the Oregon Supreme Court (OSC) issued a ruling ordering the abatement of the class action proceedings. The OSC concluded that the OPUC had primary jurisdiction to determine what, if any, remedy could be offered to PGE customers, through price reductions or refunds, for any amount of return on the Trojan investment that the Company collected in prices.

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

In 2015, based on a motion filed by PGE, the Circuit Court lifted the abatement on the class action proceedings and, heard oral argument on the Company's motion for Summary Judgment. In 2016, the Circuit Court entered a general judgment that granted the Company's motion for Summary Judgment and dismissed all claims by the plaintiffs. The plaintiffs subsequently appealed the Circuit Court dismissal to the Court of Appeals for the State of Oregon.

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

PGE believes that the 2014 OSC decision and the decisions of the Circuit Court and the Court of Appeals that followed have reduced the risk of any loss to the Company beyond the amounts previously recorded and discussed above. However, because the class actions remain subject to a potential petition for review to the OSC, management believes that it is reasonably possible that such a loss to the Company could result. As these matters involve unsettled legal theories and have a broad range of potential outcomes, sufficient information is currently not available to determine the amount of any such loss.

Deschutes River Alliance Clean Water Act Claims

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

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

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2019/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

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

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

In October 2018, DRA filed an appeal and PGE and CTWS filed cross-appeals to the Ninth Circuit Court of Appeals. In December 2019, the Court of Appeals closed the case and vacated the briefing schedule, pending ongoing discussions among the parties. On March 10, 2020, the Court of Appeals reopened the case and reset the briefing schedule.

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

10. None

11. (Reserved)

12. None

13. Changes in Officers and Directors:

On November 26, 2018, the Board of Directors of Portland General Electric Company voted to increase the size of the Board of Directors of the Company (the Board) from eleven to twelve directors and to fill the resulting vacancy by appointing Michael H. Millegan to serve as a director of the Company until the next annual meeting of shareholders, to be held on April 24, 2019. The increase in the size of the Board of Directors and Mr. Millegan's appointment were effective January 1, 2019. The Board also appointed Mr. Millegan to serve on the Audit Committee and the Finance Committee of the Board effective January 1, 2019.

On February 13, 2019, director David Dietzler indicated his plans to retire as director of the Company, effective on April 24, 2019, upon the election of directors at the Company's 2019 annual meeting of shareholders.

John McFarland, Vice President and Chief Customer Officer, was appointed to the position effective April 19, 2019.

Effective May 24, 2019, the Board of Directors of Portland General Electric Company (the "Company") voted to increase the size of the Board of Directors of the Company (the "Board") from eleven directors to twelve directors and to fill the resulting vacancy by appointing Marie Oh Huber to serve as a director of the Company until the next annual meeting of shareholders, which will be held on April 22, 2020. The Board also appointed Ms. Huber to serve on the Compensation and Human Resources Committee and the Finance Committee of the Board.

On September 10, 2019, William Nicholson, Vice President, Utility Technical Services, announced his retirement from Portland General Electric Company, effective December 31, 2019.

14. None

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	11,146,578,388	10,513,713,376
3	Construction Work in Progress (107)	200-201	329,538,575	346,348,706
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		11,476,116,963	10,860,062,082
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	5,280,409,859	4,948,724,140
6	Net Utility Plant (Enter Total of line 4 less 5)		6,195,707,104	5,911,337,942
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		6,195,707,104	5,911,337,942
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		5,734,880	2,567,291
19	(Less) Accum. Prov. for Depr. and Amort. (122)		561,673	573,481
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	79,903,863	77,812,205
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		0	0
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		88,696,635	82,427,119
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		12,948,791	2,391,252
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		186,722,496	164,624,386
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		4,151,823	6,714,924
36	Special Deposits (132-134)		16,360,268	16,380,586
37	Working Fund (135)		5,000	9,000
38	Temporary Cash Investments (136)		26,000,000	112,000,000
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		147,888,136	171,382,224
41	Other Accounts Receivable (143)		23,110,998	36,286,206
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		4,476,885	14,784,074
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		32,372	41,863
45	Fuel Stock (151)	227	34,191,533	27,662,897
46	Fuel Stock Expenses Undistributed (152)	227	0	40,377
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	51,952,091	49,232,592
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	6,121,955	3,120,107

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	3,657,581	3,627,267
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)		66,660,197	55,297,263
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)		86,440,635	96,163,635
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		37,582,745	20,436,421
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		12,948,791	2,391,252
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)		486,729,658	581,220,036
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		10,192,104	9,074,103
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	93,989,842	26,054,936
72	Other Regulatory Assets (182.3)	232	422,858,216	467,226,599
73	Prelim. Survey and Investigation Charges (Electric) (183)		395,434	1,708,425
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)		34,840	-22,139
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	13,480,470	13,853,327
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		21,808,511	15,998,527
82	Accumulated Deferred Income Taxes (190)	234	563,329,261	580,219,209
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,126,088,678	1,114,112,987
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		7,995,247,936	7,771,295,351

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2019/Q4

FOOTNOTE DATA

Schedule Page: 110 Line No.: 71 Column: c

In the third quarter of 2019, the Nuclear Regulatory Commission issued PGE a renewed license to operate the Independent Spent Fuel Storage Installation at the former Trojan location through the first quarter of 2059. PGE updated its Asset Retirement Obligation (ARO) (Acct. 230) and increased the Trojan ARO by $69 million, with a corresponding increase in Unrecovered plant (Acct. 182.2), to reflect the estimated costs through this new date.

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Portland General Electric Company	(1) [x] An Original (2) [ ] A Resubmission	/ /	end of 2019/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	1,224,651,067	1,215,804,775
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	18,838,837	18,838,837
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	23,113,532	23,113,532
11	Retained Earnings (215, 215.1, 216)	118-119	1,378,134,934	1,301,346,961
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	2,364,202	-2,304
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-9,615,910	-6,432,434
16	Total Proprietary Capital (lines 2 through 15)		2,591,259,598	2,506,442,303
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	2,607,800,000	2,487,800,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	0	65,879
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		441,860	483,555
24	Total Long-Term Debt (lines 18 through 23)		2,607,358,140	2,487,382,324
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		177,631,331	46,153,665
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		8,975,207	8,626,035
29	Accumulated Provision for Pensions and Benefits (228.3)		358,925,128	418,540,512
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		4,632,498	25,170,794
32	Long-Term Portion of Derivative Instrument Liabilities		107,979,023	101,492,253
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		279,375,319	197,325,930
35	Total Other Noncurrent Liabilities (lines 26 through 34)		937,518,506	797,309,189
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		292,625,385	279,720,480
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		5,346,207	409,419
41	Customer Deposits (235)		14,654,130	12,628,714
42	Taxes Accrued (236)	262-263	15,472,177	17,061,108
43	Interest Accrued (237)		24,608,763	26,601,559
44	Dividends Declared (238)		35,789,096	33,647,077
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2019/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		17,441,259	16,891,216
48	Miscellaneous Current and Accrued Liabilities (242)		40,413,388	46,723,070
49	Obligations Under Capital Leases-Current (243)		24,869,839	2,494,467
50	Derivative Instrument Liabilities (244)		131,143,945	151,874,495
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		107,979,023	101,492,253
52	Derivative Instrument Liabilities - Hedges (245)		0	4,166,551
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		494,385,166	490,725,903
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	0	0
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	14,557,402	139,125,688
60	Other Regulatory Liabilities (254)	278	408,556,713	400,701,445
61	Unamortized Gain on Reaquired Debt (257)		26,169	34,221
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		800,256,070	802,222,298
64	Accum. Deferred Income Taxes-Other (283)		141,330,172	147,351,980
65	Total Deferred Credits (lines 56 through 64)		1,364,726,526	1,489,435,632
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		7,995,247,936	7,771,295,351

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Schedule Page: 112 Line No.: 26 Column: c

Includes the addition of $133 million related to the North Mist Storage facility, placed in service during 2019.

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

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

Schedule Page: 112 Line No.: 34 Column: c

In the third quarter of 2019, the Nuclear Regulatory Commission issued PGE a renewed license to operate the Independent Spent Fuel Storage Installation at the former Trojan location through the first quarter of 2059. PGE updated its Asset Retirement Obligation (ARO) to reflect the estimated costs through this new date, which increased the Trojan ARO by $69 million as of September 30, 2019.

Schedule Page: 112 Line No.: 49 Column: c

Includes the addition of $16 million for the current portion of Capital Lease Obligation for North Mist Storage Facility, placed in service during 2019.

Schedule Page: 112 Line No.: 59 Column: c

Reflects a decrease due to derecognition of the North Mist Storage Facility as a build-to-suit arrangement under ASC 842 on 1/1/19, with a corresponding offset in Construction Work in Progress (Acct. 107).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

STATEMENT OF INCOME

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

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	2,147,982,409	2,005,110,043		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,109,201,823	1,013,130,293		
5	Maintenance Expenses (402)	320-323	156,494,275	140,546,552		
6	Depreciation Expense (403)	336-337	307,699,071	295,871,290		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	6,887,698	6,887,693		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	64,406,427	58,972,528		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		-1,053,972	1,337,373		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		18,618,061	13,614,738		
13	(Less) Regulatory Credits (407.4)		76,383	4,661,294		
14	Taxes Other Than Income Taxes (408.1)	262-263	132,404,584	126,448,833		
15	Income Taxes - Federal (409.1)	262-263	8,919,648	12,094,601		
16	- Other (409.1)	262-263	11,992,123	22,102,339		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	249,989,313	279,571,946		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	244,396,828	294,774,017		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		3,903,294	3,788,822		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,824,989,134	1,674,931,697		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		322,993,275	330,178,346		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
2,147,982,409	2,005,110,043					2
						3
1,109,201,823	1,013,130,293					4
156,494,275	140,546,552					5
307,699,071	295,871,290					6
6,887,698	6,887,693					7
64,406,427	58,972,528					8
						9
-1,053,972	1,337,373					10
						11
18,618,061	13,614,738					12
76,383	4,661,294					13
132,404,584	126,448,833					14
8,919,648	12,094,601					15
11,992,123	22,102,339					16
249,989,313	279,571,946					17
244,396,828	294,774,017					18
						19
						20
						21
						22
						23
3,903,294	3,788,822					24
1,824,989,134	1,674,931,697					25
322,993,275	330,178,346					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		322,993,275	330,178,346		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		2,090,267	2,793,176		
34	(Less) Expenses of Nonutility Operations (417.1)		1,937,113	2,313,308		
35	Nonoperating Rental Income (418)		-169,494	3,470,547		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	2,566,506	-60,240		
37	Interest and Dividend Income (419)		1,091,115	1,630,837		
38	Allowance for Other Funds Used During Construction (419.1)		10,350,738	10,893,676		
39	Miscellaneous Nonoperating Income (421)		2,840,629	-4,135,852		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		16,832,648	12,278,836		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)			-20,322		
45	Donations (426.1)		2,423,809	2,155,569		
46	Life Insurance (426.2)		-2,625,511	542,802		
47	Penalties (426.3)		132,974	5,432		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,199,586	920,406		
49	Other Deductions (426.5)		3,147,065	3,421,545		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		4,277,923	7,025,432		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	103,956	1,472,259		
53	Income Taxes-Federal (409.2)	262-263	-1,209,756	-205,745		
54	Income Taxes-Other (409.2)	262-263	-512,454	-72,480		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	2,116,948	4,080,244		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	788,473	5,430,472		
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)		-289,779	-156,194		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		12,844,504	5,409,598		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		118,738,532	122,549,959		
63	Amort. of Debt Disc. and Expense (428)		781,199	930,264		
64	Amortization of Loss on Reaquired Debt (428.1)		3,034,149	2,938,764		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		8,052	8,052		
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		4,692,335	3,017,293		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		5,248,924	5,730,984		
70	Net Interest Charges (Total of lines 62 thru 69)		121,989,239	123,697,244		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		213,848,540	211,890,700		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		213,848,540	211,890,700		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		1,297,494,166	1,213,474,117
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Reclassification of stranded tax effects due to Tax Reform		1,446,162	
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		1,446,162	
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		211,282,034	211,950,940
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31		238	-136,140,223	(128,005,891)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-136,140,223	(128,005,891)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		200,000	75,000
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,374,282,139	1,297,494,166
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		3,852,795	3,852,795
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		3,852,795	3,852,795
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,378,134,934	1,301,346,961
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-2,304	132,936
50	Equity in Earnings for Year (Credit) (Account 418.1)		2,566,506	(60,240)
51	(Less) Dividends Received (Debit)		200,000	75,000
52				
53	Balance-End of Year (Total lines 49 thru 52)		2,364,202	(2,304)

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	213,848,540	211,890,700
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	378,993,196	361,731,511
5	Amortization of Debt Discount	3,807,296	3,860,976
6	Amortization of Unrecovered Plant	-1,053,972	1,337,373
7	Net Price Risk Management Activities	-42,043,425	-67,851,811
8	Deferred Income Taxes (Net)	6,920,960	-16,552,299
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	32,409,703	-15,868,717
11	Net (Increase) Decrease in Inventory	-12,239,920	-4,831,522
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	1,612,200	53,735,147
14	Net (Increase) Decrease in Other Regulatory Assets	53,583,712	75,577,212
15	Net Increase (Decrease) in Other Regulatory Liabilities	-19,571,074	38,567,394
16	(Less) Allowance for Other Funds Used During Construction	10,350,738	10,893,676
17	(Less) Undistributed Earnings from Subsidiary Companies	2,566,506	-60,240
18	Other: Margin and Customer Deposits	2,045,734	-5,877,298
19	Other: Operating	-62,058,994	4,888,747
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	543,336,712	629,773,977
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-614,595,774	-560,895,227
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-69,378	-3,944,473
30	(Less) Allowance for Other Funds Used During Construction	-10,350,738	-10,893,676
31	Other Capital Activities	-1,066,616	123,860,346
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-605,381,030	-430,085,678
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38	Sale of Property	325,819	1,347,171
39	Investments in and Advances to Assoc. and Subsidiary Companies		-45,204,565
40	Contributions and Advances from Assoc. and Subsidiary Companies	200,000	
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Other Investments	-5,173,341	-2,469,336
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Purchases of Trojan Decommissioning Securities	-8,488,330	-12,105,038
54	Sales of Trojan Decommissioning Securities	13,113,169	14,613,050
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-605,403,713	-473,904,396
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	470,000,000	75,000,000
62	Preferred Stock		
63	Common Stock	-2,270,471	-2,187,650
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	467,729,529	72,812,350
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-350,065,879	-23,605,989
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-8,766,000	
77	Debt Issue Costs	-1,863,172	
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-133,534,578	-125,287,800
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-26,500,100	-76,081,439
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-88,567,101	79,788,142
87			
88	Cash and Cash Equivalents at Beginning of Period	118,723,924	38,935,782
89			
90	Cash and Cash Equivalents at End of period	30,156,823	118,723,924

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

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

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

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

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

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

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

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

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

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

Amount represents extinguishment costs of long term debt.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Supplemental Disclosures

Supplemental Information to Statement of Cash Flows

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

	Balance at Beginning of Year	Balance at End of Year
Cash (131)	$ 6,714,924	$ 4,151,823
Working Funds (135)	9,000	5,000
Temporary Cash Investments (136)	112,000,000	26,000,000
	$ 118,723,924	$ 30,156,823

	2018	2019
Cash paid during the year:		
Interest	$ 122,775,667	$ 120,967,642
Allowance for borrowed funds used during construction	(5,730,984)	(5,248,924)
	$ 117,044,683	$ 115,718,718
Income Taxes	$ 24,923,371	$ 32,913,552
Non-cash investing and financing activities:		
Accrued capital additions	$ 60,573,744	$ 76,125,230
Accrued dividends payable	33,647,077	35,789,096
Assets obtained under leasing arrangements under ASC 842:		
Finance leases	—	153,811,914
Operating leases	—	56,460,807
Preliminary engineering transferred to Construction work in progress	2,124,989	1,667,673
Assets placed under capital lease under ASC 840	23,514,053	—

NOTE 1: BASIS OF PRESENTATION

Nature of Operations

Portland General Electric Company (PGE or the Company) is a single, vertically-integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon. The Company also participates in the wholesale market by purchasing and selling electricity and natural gas in an effort to obtain reasonably-priced power for its retail customers. PGE operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. The Company's corporate headquarters is located in Portland, Oregon and its approximately 4,000 square mile, state-approved service area is located entirely within the state of Oregon. PGE's allocated service area includes 51 incorporated cities. As of December 31, 2019, PGE served approximately 895,000 thousand retail customers with a service area population of approximately 1.9 million.

As of December 31, 2019, PGE had 2,949 employees, with 775 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 719 and 56 employees and expire March 2022 and August 2022, respectively.

PGE is subject to the jurisdiction of the Public Utility Commission of Oregon (OPUC) with respect to retail prices, utility services, accounting policies and practices, issuances of securities, and certain other matters. Retail prices are based on the Company's cost to serve customers, including an opportunity to earn a reasonable rate of return, as determined by the OPUC. The Company is also subject to regulation by the Federal Energy Regulatory Commission (FERC) in matters related to wholesale energy transactions, transmission services, reliability standards, natural gas pipelines, hydroelectric project licensing, accounting policies and practices, short-term debt issuances, and certain other matters.

Financial Statements

These financial statements have been prepared in accordance with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (GAAP). As a result, the presentation of these financial statements differs from GAAP.

The primary differences include the requirement that PGE report its investments in majority-owned subsidiaries on the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiaries, as required by GAAP. In addition, the FERC requires that certain items on the Comparative Balance Sheet be classified differently than that required by GAAP, primarily the classification of components of accumulated deferred income taxes, long-term debt, regulatory assets and liabilities, accumulated asset retirement removal costs, and the non-service component of pension expense.

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

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

Use of Estimates

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

Subsequent events

PGE has evaluated the impact of events occurring after December 31, 2019 up to February 13, 2020, the date that the Company's U.S. GAAP financial statements were issued, and has updated such evaluation for disclosure purposes through March 27, 2020. These financial statements include all necessary adjustments and disclosures resulting from such evaluations.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash and Cash Equivalents

Highly liquid investments with maturities of three months or less at the date of acquisition are classified as Temporary Cash Investments, of which PGE had $26 million as of December 31, 2019 and $112 million as of December 31, 2018 reflected in the

Comparative Balance Sheet.

Customer Accounts Receivable

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

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

Provisions for Accumulated Provision for Uncollectible Accounts related to wholesale sales are charged to Purchased Power and are recorded periodically based on a review of counterparty non-performance risk and contractual right of offset when applicable. There have been no material write-offs of Customer Accounts Receivable related to wholesale sales in 2019 or 2018.

Price Risk Management

PGE engages in price risk management activities, utilizing financial instruments such as forward, future, swap, and option contracts for electricity, natural gas, and foreign currency. These instruments are measured at fair value and recorded on the Comparative Balance Sheet as assets or liabilities from price risk management activities. Changes in fair value are recognized in the Statement of Income, offset by the effects of regulatory accounting. Certain electricity forward contracts that were entered into in anticipation of serving the Company’s regulated retail load may meet the requirements for treatment under the normal purchases and normal sales scope exception. Such contracts are not recorded at fair value and are recognized under accrual accounting.

Price risk management activities are utilized as economic hedges to protect against variability in expected future cash flows due to associated price risk and to manage exposure to volatility in net 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.

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 $16 million as of December 31, 2019 and 2018. Letters of credit provided as collateral are not recorded on the Company’s Comparative Balance Sheet and were $15 million and $48 million as of December 31, 2019 and 2018, 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

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Capitalization Policy

Utility Plant is capitalized at original cost, which includes direct labor, materials and supplies, and contractor costs, as well as indirect costs such as engineering, supervision, employee benefits, and an allowance for funds used during construction (AFDC). Plant replacements are capitalized, with minor items charged to expense as incurred. Periodic major maintenance inspections and overhauls at PGE's generating plants are charged to expense as incurred, subject to regulatory accounting as applicable. Costs to purchase or develop software applications for internal use only are capitalized and amortized over the estimated useful life of the software. Costs of obtaining FERC licenses for the Company's hydroelectric projects are capitalized and amortized over the related license period.

During the period of construction, costs expected to be included in the final value of the constructed asset, and depreciated once the asset is complete and placed in service, are classified as Construction Work In Progress (CWIP) in Utility Plant on the Comparative Balance Sheet. If the project becomes probable of being abandoned, such costs are expensed in the period such determination is made. If any costs are expensed, PGE may seek recovery of such costs in customer prices, although there can be no guarantee such recovery would be granted. Costs disallowed for recovery in customer prices, if any, are charged to expense at the time such disallowance becomes probable.

PGE records AFDC, which is intended to represent the Company's cost of funds used for construction purposes, based on the rate granted in the latest general rate case for equity funds and the cost of actual borrowings for debt funds. AFDC is capitalized as part of the cost of plant and credited to the Statement of Income. The average rate used by PGE was 7.1% in 2019 and 7.3% in 2018. AFDC from borrowed funds was $5 million in 2019 and $6 million in 2018 and is reflected as a reduction to Interest Charges. AFDC from equity funds, included in Other Income, was $10 million in 2019 and $11 million in 2018.

On December 31, 2019, the FERC approved PGE's request to reclassify the functional asset classification of certain 115kV facilities from Distribution to Transmission to align classification with the primary function of these assets. As a result, on December 31, 2019, PGE reclassified $223 million of Utility Plant in service assets from Distribution to Transmission. Accumulated Provision for Depreciation, Amortization, and Depletion related to these facilities is $113 million as of December 31, 2019. Additions to such assets, or construction of similar types of assets, will be classified as Transmission going forward.

Depreciation and Amortization

Depreciation is computed using the straight-line method, based upon original cost, and includes an estimate for cost of removal and expected salvage. Depreciation Expense as a percent of the related average depreciable plant in service was 3.6% in 2019 and 2018. A component of Depreciation Expense includes estimated asset retirement removal costs allowed in customer prices.

Periodic studies are conducted to update depreciation parameters (i.e. retirement dispersion patterns, average service lives, and net salvage rates), including estimates of asset retirement obligations (AROs) and asset retirement removal costs. The studies are conducted at a minimum of every five years and are filed with the OPUC for approval and inclusion in a future rate proceeding. The most recent depreciation study was completed based on 2015 data, with an order received from the OPUC in September 2017 authorizing new depreciation rates effective January 1, 2018. This study was incorporated into the Company's 2018 general rate case filed with the OPUC in 2017.

Thermal generation plants are depreciated using a life-span methodology which ensures that plant investment is recovered by the estimated retirement dates, which range from 2020 to 2059. Depreciation is provided on PGE's other classes of plant in service over their estimated average service lives, which are as follows (in years):

Generation, excluding thermal:	
Hydro	98
Wind	30
Transmission	59
Distribution	46
General	12

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

Intangible plant consists primarily of computer software development costs, which are amortized over either five or ten years, and hydro licensing costs, which are amortized over the applicable license term, which range from 30 to 50 years. Accumulated amortization was $366 million and $302 million as of December 31, 2019 and 2018, respectively, with amortization expense of $64 million in 2019 and $59 million in 2018. Future estimated amortization expense as of December 31, 2019 is as follows: $60 million in 2020; $52 million in 2021; $46 million in 2022; $37 million in 2023; and $32 million in 2024.

Marketable Securities

Nuclear decommissioning trust

Reflects assets held in trust to cover general decommissioning costs and operation of the Independent Spent Fuel Storage Installation (ISFSI) at the decommissioned Trojan nuclear power plant (Trojan), which was closed in 1993. The Nuclear decommissioning trust (NDT) includes amounts collected from customers, less qualified expenditures, plus any realized and unrealized gains and losses on the investments held therein.

Non-qualified benefit plan trust

Reflects assets held in trust to cover the obligations of PGE’s non-qualified benefit plans (NQBP) and represents contributions made by the Company, less qualified expenditures, plus any realized and unrealized gains and losses on the investments held therein.

All of PGE’s investments in marketable securities included in NDT and NQBP trust on the Comparative Balance Sheet, are classified as equity or trading debt securities. These securities are classified as noncurrent because they are not available for use in operations. Such securities are stated at fair value based on quoted market prices. Realized and unrealized gains and losses on the NQBP trust assets are included in Other Income. Realized and unrealized gains and losses on the NDT fund assets are recorded as regulatory liabilities or assets, respectively, for future ratemaking treatment. The cost of securities sold is based on the average cost method.

Regulatory Accounting

Regulatory Assets and Liabilities

As a rate-regulated enterprise, PGE applies regulatory accounting, which results in the creation of regulatory assets and regulatory liabilities. Regulatory assets represent: i) probable future revenue associated with certain actual or estimated costs that are expected to be recovered from customers through the ratemaking process; or ii) probable future collections from customers resulting from revenue accrued for completed alternative revenue programs, provided certain criteria are met. Regulatory liabilities represent probable future reductions in revenue associated with amounts that are expected to be credited to customers through the ratemaking process. Regulatory accounting is appropriate as long as: i) prices are established by, or subject to, approval by independent third-party regulators; ii) prices are designed to recover the specific enterprise’s cost of service; and iii) in view of demand for service, it is reasonable to assume that prices set at levels that will recover costs can be charged to and collected from customers. Once the regulatory asset or liability is reflected in prices, the respective regulatory asset or liability is amortized to the appropriate line item in the Statement of Income over the period in which it is included in prices.

Circumstances that could result in the discontinuance of regulatory accounting include: i) increased competition that restricts PGE’s ability to establish prices to recover specific costs; and ii) a significant change in the manner in which prices are set by regulators from cost-based regulation to another form of regulation. The Company periodically reviews the criteria of regulatory accounting to ensure that its continued application is appropriate. Based on a current evaluation of the various factors and conditions, management believes that recovery of PGE’s regulatory assets is probable.

For additional information concerning the Company’s regulatory assets and liabilities, see Note 6, Regulatory Assets and Liabilities.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Power Cost Adjustment Mechanism

PGE is subject to a power cost adjustment mechanism (PCAM), as approved by the OPUC. Pursuant to the PCAM, future customer prices can be adjusted to reflect a portion of the difference between: i) NVPC forecast each year and included in customer prices (baseline NVPC); and ii) actual NVPC for the year. NVPC consists of the cost of power purchased and fuel used to generate electricity to meet PGE's retail load requirements, as well as the cost of settled electric and natural gas financial contracts, all of which is classified as Purchased Power in the Company's Statement of Income, and is net of wholesale sales, which are classified as Operating Revenues in the Statement of Income.

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

To the extent actual NVPC, subject to certain adjustments, is outside the deadband range, the PCAM provides for 90% of the excess variance to be collected from, or refunded to, customers. Pursuant to a regulated earnings test, a refund will occur only to the extent that it results in PGE's actual regulated return on equity (ROE) for the given year being no less than 1% above the Company's latest authorized ROE, while a collection will occur only to the extent that it results in PGE's actual regulated ROE for that year being no greater than 1% below the Company's authorized ROE. PGE's authorized ROE was 9.5% for 2019 and 2018.

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

Asset Retirement Obligations

Legal obligations related to the future retirement of tangible long-lived assets are classified as AROs on PGE's Comparative Balance Sheet. An ARO is recognized in the period in which the legal obligation is incurred, and when the fair value of the liability can be reasonably estimated. Due to the long lead time involved until decommissioning activities occur, the Company uses present value techniques because quoted market prices and market-risk premiums are not available. The present value of estimated future decommissioning costs is capitalized and included in 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 are charged to Miscellaneous Nonoperating Income (Acct 421) on the Statement of Income. Such estimates are revised periodically, with actual settlements charged to the ARO as incurred.

The estimated capitalized costs of AROs are depreciated over the estimated life of the related asset, with such depreciation included in Depreciation Expense for Asset Retirement Costs in the Statement of Income. Changes in the ARO resulting from the passage of time (accretion) is based on the original discount rate and recognized as an increase in the carrying amount of the liability and as a charge to accretion expense, which is included in Accretion Expense for Asset (Acct 411) in the Company's Statement of Income.

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

The difference between the timing of the recognition of ARO depreciation and accretion expenses and the amount included in customers' prices is recorded as a regulatory asset or liability in the Company's Comparative Balance Sheet. As of December 31, 2019, PGE had a net regulatory liability related to Utility plant AROs in the amount of $54 million and a net regulatory asset related to Trojan decommissioning ARO activities of $91 million. As of December 31, 2018, PGE had a net regulatory liability related to Utility plant AROs in the amount of $53 million and a net regulatory asset related to Trojan decommissioning ARO activities of $25 million. For additional information concerning the Company's regulatory assets and liabilities related to AROs, see Note 6, Regulatory Assets and Liabilities.

Contingencies

Contingencies are evaluated using the best information available at the time the financial statements are prepared. Legal costs incurred in connection with loss contingencies are expensed as incurred. Loss contingencies, including environmental contingencies, are accrued, and disclosed if material, when it is probable that an asset has been impaired, or a liability incurred, as of the financial statement date and the amount of the loss can be reasonably estimated. If a reasonable estimate of probable loss cannot be determined, a range of loss may be established, in which case the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate.

A loss contingency will also be disclosed when it is reasonably possible that an asset has been impaired, or a liability, incurred if the estimate or range of potential loss is material. If a probable or reasonably possible loss cannot be determined, then the Company: i) discloses an estimate of such loss or the range of such loss, if the Company is able to determine such an estimate; or ii) discloses that an estimate cannot be made and the reasons why the estimate cannot be made.

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

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

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

Accumulated Other Comprehensive Loss

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

Revenue Recognition

Operating Revenues are is recognized when obligations under the terms of a contract with customers are satisfied. Generally, this satisfaction of performance obligations and transfer of control occurs and 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 $45 million in 2019 and 2018.

Retail revenue is billed based on monthly meter readings taken at various cycle dates throughout the month. At the end of each month, PGE estimates the revenue earned from energy deliveries that remained unbilled to customers. The estimate, which is classified as Accrued Utility Revenues in the Company's Comparative Balance Sheet, is calculated based on actual net retail system load each month, the number of days from the last meter read date through the last day of the month, and current customer prices.

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

Stock-Based Compensation

The measurement and recognition of compensation expense for all share-based payment awards, including restricted stock units, is based on the estimated fair value of the awards. The fair value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite vesting period. PGE attributes the value of stock-based compensation to expense on a straight-line basis. For additional information concerning the Company's Stock-Based Compensation, see Note 13, Stock-Based Compensation Expense.

Income Taxes

Income taxes are accounted for under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between financial statement carrying amounts and tax bases of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in current and future periods that includes the enactment date. Any valuation allowance would be established to reduce deferred tax assets to the "more likely than not" amount expected to be realized in future tax returns.

Unrecognized tax benefits represent management's expected treatment of a tax position taken in a filed tax return or planned to be taken in a future tax return, that has not been reflected in measuring income tax expense for financial reporting purposes. Until such positions are no longer considered uncertain, PGE would not recognize the tax benefits resulting from such positions and would report the tax effect as a liability in the Company's Comparative Balance Sheet.

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

Recent Accounting Pronouncements

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

In August 2018, the FASB issued ASU 2018-15 *Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract*, to provide guidance on implementation costs incurred in a cloud computing arrangement that is a service contract. PGE plans to continue to capitalize such implementation costs to Utility Plant for FERC accounting. ASU 2018-15 aligns the accounting for such costs with the guidance on capitalizing costs associated with developing or obtaining internal-use software. For calendar year-end entities, the update will be effective for annual periods beginning on January 1, 2020. Early adoption is permitted, including adoption in an interim period. The amendments in this update may be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. PGE does not expect the adoption to have a material impact on the financial statements and does not plan to early adopt.

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

Recently Adopted Accounting Pronouncements

On January 1, 2019, PGE adopted ASU 2016-02, *Leases* (Topic 842), which supersedes the previous lease accounting requirements for lessees and lessors within Topic 840, *Leases*. The Company elected the practical expedient provided under ASU 2018-11, *Leases (Topic 842) Targeted Improvements*, which amended ASU 2016-02 to provide entities an optional transition practical expedient to adopt the new standard with a cumulative effect adjustment as of the beginning of the year of adoption with prior year comparative financial information and disclosures remaining as previously reported. As a result, no adjustments were made to the Comparative

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Balance Sheet prior to January 1, 2019 and amounts are reported in accordance with historical accounting under Topic 840, while the Comparative Balance Sheet as of December 31, 2019 is presented under Topic 842. The Company also elected the practical expedient provided under ASU 2018-01, *Leases (Topic 842) Land Easement Practical Expedient for Transition to Topic 842*, which amended ASU 2016-02 to provide entities an optional transition practical expedient to not evaluate under Topic 842, existing or expired land easements that were not previously accounted for as leases under the previous leases guidance in Topic 840. Effective January 1, 2019, PGE evaluates new or modified land easements under Topic 842.

PGE's transition to the new lease standard did not result in a material adjustment to beginning retained earnings and the Company expects the adoption of the new standard to have an immaterial impact to its results of operations on an ongoing basis. Upon transition, PGE elected to reassess all arrangements that may contain a lease and their resulting lease classification which resulted in the following Comparative Balance Sheet adjustments as of January 1, 2019: i) the recognition of right-of-use assets and liabilities from operating and finance leases of $44 million pursuant to the new standard; ii) the derecognition of existing build-to-suit assets and liabilities of $131 million that were no longer considered to meet build-to-suit criteria under Topic 842 and were not recognized on the Company's Comparative Balance Sheet until commencement, which occurred in the second quarter of 2019; and iii) the derecognition of $49 million in lease assets and liabilities related to an existing gas pipeline lateral capital lease that no longer met the definition of a lease under the new standard. The following table illustrates the adjustments made upon adoption of Topic 842 and the corresponding line items affected on the Company's Comparative Balance Sheet (in millions):

	January 1, 2019 Topic 842 Adoption Adjustments			
	Increase due to existing operating and finance leases	**Decrease due to build-to-suit reassessment**	**Decrease due to capital lease reassessment**	**Total Increase/(Decrease)**
Assets				
Net Utility Plant	$ 44	$ (131)	$ (49)	$ (178)
Liabilities				
Obligations Under Capital Leases - Current	5	—	(2)	3
Obligations Under Capital Leases - Noncurrent	39		(47)	(8)
Other Deferred Credits		(131)		(131)

For new required disclosures and further information see Note 17, Leases. The transition to the new standard did not have a material impact on the Company's financial position.

On January 1, 2019 PGE adopted ASU 2018-02 *Income Statement—Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income* (ASU 2018-02). ASU 2018-02 allows for a reclassification from accumulated other comprehensive income to retained earnings for the stranded tax effects resulting from the United States Tax Cuts and Jobs Act of 2017 (TCJA). The amendments only relate to the reclassification of the income tax effects of the TCJA, and therefore the underlying guidance that requires that the effect of a change in tax laws or rates be included in income from continuing operations is not affected. PGE elected to make such reclassification, as provided by the FERC in Docket No. AC19-19-000. As a result, PGE reclassified $1,446,162 from Accumulated other compressive loss to Retained earnings (Account 439) during the period of adoption rather than applying the standard retrospectively. The implementation did not result in a material impact to the results of operation, financial position or statements of cash flows.

NOTE 3: COMPARATIVE BALANCE SHEET COMPONENTS

Accumulated Provision for Uncollectible Accounts

Name of Respondent Portland General Electric Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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

	Years Ended December 31,	
	2019	**2018**
Balance as of beginning of year	$ 15	$ 6
Increase in provision	2	14
Amounts written off, less recoveries	(13)	(5)
Balance as of end of year	$ 4	$ 15

Net Utility Plant

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

	As of December 31,	
	2019	**2018**
Utility Plant:		
Generation	$ 4,954	$ 4,762
Transmission	849	585
Distribution	3,917	3,836
General	661	611
Intangible	758	715
Total in service	11,139	10,509
Less: Accumulated Provision for Depreciation, Amortization, and Depletion	(5,280)	(4,949)
Total in service, net	5,859	5,560
Held for future use	7	5
Construction Work In Progress	330	346
Net Utility Plant	$ 6,196	$ 5,911

NOTE 4: FAIR VALUE OF FINANCIAL INSTRUMENTS

PGE determines the fair value of financial instruments, both assets and liabilities recognized and not recognized in the Company's Comparative Balance Sheet, for which it is practicable to estimate fair value as of December 31, 2019 and 2018. The Company then classifies these financial assets and liabilities based on a fair value hierarchy that is applied to prioritize the inputs to the valuation techniques used to measure fair value. The three levels of the fair value hierarchy and application to the Company are discussed below.

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the measurement date.

Level 2 Pricing inputs include those that are directly or indirectly observable in the marketplace as of the measurement date.

Level 3 Pricing inputs include significant inputs that are unobservable for the asset or liability.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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, 2019 and 2018, except those presented in this note.

The Company's financial assets and liabilities whose values were recognized at fair value are as follows by level within the fair value hierarchy (in millions):

	As of December 31, 2019				
	Level 1	**Level 2**	**Level 3**	**Other(2)**	**Total**
Assets:					
Temporary Cash Investments	$ 26	$ —	$ —	$ —	$ 26
Nuclear decommissioning trust: (1)					
Debt securities:					
Domestic government	8	16	—	—	24
Corporate credit	—	9	—	—	9
Money market funds measured at NAV (2)	—	—	—	13	13
Non-qualified benefit plan trust: (3)					
Money market funds	1	—	—	—	1
Equity securities—domestic	7	—	—	—	7
Debt securities—domestic government	1	—	—	—	1
Price risk management activities: (1) (4)					
Electricity	—	9	7	—	16
Natural gas	—	21	1	—	22
	$ 43	$ 55	$ 8	$ 13	$ 119
Liabilities:					
Price risk management activities: (1) (4)					
Electricity	$ —	$ 14	$ 105	$ —	$ 119
Natural gas	—	12	—	—	12
	$ —	$ 26	$ 105	$ —	$ 131

(1) Activities are subject to regulation, with gains and losses deferred pursuant to regulatory accounting and included in Other Regulatory Assets or Other Regulatory Liabilities as appropriate.
(2) Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.
(3) Excludes insurance policies of $29 million, which are recorded at cash surrender value.
(4) For further information regarding price risk management derivatives, see Note 5, Risk Management.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

	As of December 31, 2018				
	Level 1	**Level 2**	**Level 3**	**Other(2)**	**Total**
Assets:					
Temporary Cash Investments	$ 112	$ —	$ —	$ —	$ 112
Nuclear decommissioning trust: (1)					
Debt securities:					
Domestic government	7	18	—	—	25
Corporate credit	—	10	—	—	10
Money market funds measured at NAV (2)	—	—	—	7	7
Non-qualified benefit plan trust: (3)					
Money market funds	2	—	—	—	2
Equity securities—domestic	6	—	—	—	6
Debt securities—domestic government	1	—	—	—	1
Price risk management activities: (1) (4)					
Electricity	—	9	3	—	12
Natural gas	—	8	—	—	8
	$ 128	$ 45	$ 3	$ 7	$ 183
Liabilities:					
Interest rate swap derivatives	$ —	$ 4	$ —	$ —	4
Price risk management activities: (1) (4)					
Electricity	—	10	84	—	94
Natural gas	—	51	7	—	58
	$ —	$ 65	$ 91	$ —	$ 156

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in Other Regulatory Assets or Other Regulatory Liabilities as appropriate.
(2) Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.
(3) Excludes insurance policies of $27 million, which are recorded at cash surrender value.
(4) For further information regarding price risk management derivatives, see Note 5, Risk Management.

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. These Temporary Cash Investments are classified as Level 1 in the fair value hierarchy due to the availability of quoted prices for identical assets in an active market as of the measurement date. Principal markets for money market fund prices include published exchanges such as National Association of Securities Dealers Automated Quotations (NASDAQ) and the New York Stock Exchange (NYSE).

Assets held in the NDT and NQBP trusts are recorded at fair value as Other Special Funds in PGE's Comparative Balance Sheet and invested in securities that are exposed to interest rate, credit, and market volatility risks. These assets are classified within Level 1, 2, or 3 based on the following factors:

Debt securities—PGE invests in highly-liquid United States Treasury securities to support the investment objectives of the trusts. These domestic government securities are classified as Level 1 in the fair value hierarchy due to the availability of quoted prices for identical assets in an active market as of the measurement date.

Assets classified as Level 2 in the fair value hierarchy include domestic government debt securities, such as municipal debt, and corporate credit securities. Prices are determined by evaluating pricing data such as broker quotes for similar securities and adjusted for observable differences. Significant inputs used in valuation models generally include benchmark yield and issuer spreads. The external credit rating, coupon rate, and maturity of each security are considered in the valuation, as applicable.

Equity securities—Equity mutual fund and common stock securities are classified as Level 1 in the fair value hierarchy due to the availability of quoted prices for identical assets in an active market as of the measurement date. Principal markets for equity prices include published exchanges such as NASDAQ and the NYSE.

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

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

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

Assets and liabilities from price risk management activities are recorded at fair value in PGE's Comparative Balance Sheet and consist of derivative instruments entered into by the Company to manage its exposure to commodity price risk and foreign currency exchange rate risk and to reduce volatility in NVPC. For 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.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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, 2019:							
Electricity physical forward	$ —	$ 104	Discounted cash flow	Electricity forward price (per MWh)	$ 12.53	$ 59.00	$ 36.92
Natural gas financial swaps	1	—	Discounted cash flow	Natural gas forward price (per Dth)	1.39	3.73	1.90
Electricity financial futures	7	1	Discounted cash flow	Electricity forward price (per MWh)	10.57	66.32	45.11
	$ 8	$ 105					
As of December 31, 2018:							
Electricity physical forward	$ 3	$ 84	Discounted cash flow	Electricity forward price (per MWh)	$ 14.60	$ 69.00	$ 45.00
Natural gas financial swaps	—	7	Discounted cash flow	Natural gas forward price (per Dth)	0.95	4.64	1.82
Electricity financial futures	—	—	Discounted cash flow	Electricity forward price (per MWh)	20.75	35.46	28.63
	$ 3	$ 91					

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)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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, 2019	2018
Net liabilities from price risk management activities as of beginning of year	$ 88	$ 139
Net realized and unrealized losses/(gains) *	10	(40)
Net transfers out of Level 3 to Level 2	(1)	(11)
Net liabilities from price risk management activities as of end of year	$ 97	$ 88
Level 3 net unrealized losses/(gains) that have been fully offset by the effect of regulatory accounting	$ 16	$ (32)

* Includes $6 million in net realized gains in 2019 and $8 million in 2018.

Transfers into Level 3 occur when significant inputs used to value the Company's derivative instruments become less observable, such as a delivery location becoming significantly less liquid. During the years ended December 31, 2019 and 2018, there were no transfers into Level 3 from Level 2. Transfers out of Level 3 occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery term of a transaction becomes shorter. PGE records transfers in and transfers out of Level 3 at the end of the reporting period for all of its derivative instruments.

Transfers from Level 2 to Level 1 for the Company's price risk management assets and liabilities do not occur as quoted prices are not available for identical instruments. As such, the Company's assets and liabilities from price risk management activities mature and settle as Level 2 fair value measurements.

Long-term debt is recorded at amortized cost in PGE's Comparative Balance Sheet. The fair value of the Company's First Mortgage Bonds (FMBs) and Pollution Control Revenue Bonds (PCRBs) is classified as a Level 2 fair value measurement.

As of December 31, 2019, the carrying amount of PGE's long-term debt was $2,608 million and its estimated aggregate fair value was $3,039 million. As of December 31, 2018, the carrying amount of PGE's long-term debt was $2,488 million with an estimated aggregate fair value of $2,760 million.

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

NOTE 5: RISK MANAGEMENT

Price Risk Management

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

PGE utilizes derivative instruments to manage its exposure to commodity price risk and foreign exchange rate risk in order to manage volatility in NVPC for its retail customers. Such derivative instruments, recorded at fair value on the Comparative Balance Sheet, may

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

include forward, futures, swap, and option contracts for electricity, natural gas, and foreign currency, with changes in fair value recorded in the Statement of Income. In accordance with ratemaking and cost recovery processes authorized by the OPUC, the Company recognizes a regulatory asset or liability to defer the gains and losses from derivative activity until settlement of the associated derivative instrument. PGE may designate certain derivative instruments as cash flow hedges or may use derivative instruments as economic hedges. The Company does not engage in trading activities for non-retail purposes.

PGE's assets and liabilities from price risk management activities consist of the following (in millions):

	As of December 31, 2019	As of December 31, 2018
Current assets:		
Commodity contracts:		
Electricity	$ 9	$ 11
Natural gas	16	7
Total current derivative assets	25	18
Noncurrent assets:		
Commodity contracts:		
Electricity	7	1
Natural gas	6	1
Total noncurrent derivative assets	13	2
Total derivative assets	$ 38	$ 20
Current liabilities:		
Commodity contracts:		
Electricity	$ 14	$ 16
Natural gas	9	35
Total current derivative liabilities	23	51
Noncurrent liabilities:		
Commodity contracts:		
Electricity	105	78
Natural gas	3	23
Total noncurrent derivative liabilities	108	101
Total derivative liabilities	$ 131	$ 152

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, 2019		As of December 31, 2018	
Commodity contracts:				
Electricity	6	MWh	5	MWh
Natural gas	145	Dth	123	Dth
Foreign currency exchange	$ 23	Canadian	$ 18	Canadian

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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, 2019, PGE had no material gross master netting arrangements. As of December 31, 2018, gross amounts included as Derivative Instrument Liabilities subject to master netting agreements were $88 million, for which PGE posted collateral of $11 million, which consisted entirely of letters of credit. Of the gross amounts recognized as of December 31, 2018, $84 million was for electricity and $4 million was for natural gas.

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

	Years Ended December 31,	
	2019	**2018**
Commodity contracts:		
Electricity	$ 20	$ (34)
Natural Gas	(32)	21
Foreign currency exchange	(1)	1

Net unrealized and certain net realized losses (gains) presented in the table above are offset within the Statement of Income by the effects of regulatory accounting. Of the net amounts recognized in Net income, net gains of $2 million, and $18 million for the years ended December 31, 2019 and 2018, respectively, have been offset.

Assuming no changes in market prices and interest rates, the following table presents the years in which the net unrealized (gains)/losses recorded as of December 31, 2019 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2020	**2021**	**2022**	**2023**	**2024**	**Thereafter**	**Total**
Commodity contracts:							
Electricity	$ 5	$ 1	$ 7	$ 7	$ 7	$ 76	$ 103
Natural gas	(7)	(2)	(1)	—	—	—	(10)
Net unrealized (gain)/loss	$ (2)	$ (1)	$ 6	$ 7	$ 7	$ 76	$ 93

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, 2019 was $122 million, for which the Company has posted $15 million in collateral, consisting entirely of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered as of December 31, 2019, the cash requirement to either post as collateral or settle the instruments immediately would have been $114 million. As of December 31, 2019, PGE had no posted cash collateral for derivative instruments with no credit-risk-related contingent features. Cash collateral for derivative instruments is classified as Special Deposits on the Company's Comparative Balance Sheet.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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

	As of December 31,	
	2019	**2018**
Assets from price risk management activities:		
Counterparty A	35%	42%
Counterparty B	1	15
Counterparty C	13	5
Counterparty D	11	6
Counterparty E	11	9
	71%	77%
Liabilities from price risk management activities:		
Counterparty F	79%	56%

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

Interest Rate Risk

In 2018 PGE entered into two forward starting interest rate swap lock agreements to hedge a portion of its interest rate risk associated with anticipated issuances of fixed-rate, long-term debt securities. These derivative instruments were designated as cash flow hedges, protecting against the risk of changes in future interest payments that could have resulted from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance.

As of December 31, 2018, the fair value of the interest rate swaps was a $4 million liability, which was recorded in Derivative Instrument Liabilities - Hedges on the Company's Comparative Balance Sheet. The swaps settled at a $5 million loss in January 2019, which was recorded in Other Regulatory Assets on the Comparative Balance Sheet, and will be amortized as a component of interest expense over the life of the associated debt. Such amounts are also included as a component of cost of debt for ratemaking purposes. As of December 31, 2019, the Company had no outstanding interest rate swaps.

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,	
		2019	**2018**
		Total	**Total**
Regulatory assets:			
Price risk management	2035	$ 95	$ 131
Pension and other postretirement plans	(1)	213	222
Deferred income taxes	(3)	45	50

Name of Respondent Portland General Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Other	Various	70	64
Total regulatory assets		$ 423	$ 467
Regulatory liabilities:			
Deferred income taxes	(3)	304	317
Asset retirement obligations	(2)	54	53
Other	Various	51	31
Total regulatory liabilities		$ 409	$ 401

(1) Recovery expected over the average service life of employees.
(2) Recovery or refund expected over the estimated lives of the underlying assets and treated as a reduction to rate base.
(3) Refund expected primarily through amortization using the average rate assumption method over the average life of the underlying assets and treated as a reduction to rate base.

Price risk management represents the difference between the net unrealized losses recognized on derivative instruments related to price risk management activities and their realization and subsequent recovery in customer prices. For further information regarding assets and liabilities from price risk management activities, see Note 6, Risk Management.

Pension and other postretirement plans represents unrecognized components of the benefit plans' funded status, which are recoverable in customer prices when recognized in net periodic pension and postretirement benefit costs. For further information, see Note 10, Employee Benefits.

Debt issuance costs represents unrecognized debt issuance costs related to debt instruments retired prior to the stipulated maturity date.

Trojan decommissioning activities represents the deferral of ongoing costs associated with monitoring spent nuclear fuel at Trojan, net of amortization of customer collections. In addition, proceeds received from the United States Department of Energy (USDOE) for the reimbursement of costs to monitor the ISFSI is deferred and subsequently refunded to customers.

Deferred income taxes represents income tax benefits primarily from property-related timing differences that will be refunded to customers when the temporary differences reverse. Substantially all of the amounts deferred are subject to tax normalization rules that require that the impact to the results of operations of amortizing the excess deferred income tax balance cannot occur more rapidly than over the book life of the related assets. The Company uses the average rate assumption method to account for the refund to customers. For further information, see Note 11, Income Taxes.

Asset retirement obligations represents the difference in the timing of recognition of: i) the amounts recognized for Depreciation Expense of the asset retirement costs and Accretion Expense of the ARO; and ii) the amount recovered in customer prices.

NOTE 7: ASSET RETIREMENT OBLIGATIONS

AROs consist of the following (in millions):

	As of December 31,	
	2019	**2018**
Trojan decommissioning activities	$ 137	$ 68
Utility plant	126	112
Non-utility property	16	17
Total asset retirement obligations	$ 279	$ 197

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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 (NRC). 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 the third quarter of 2019, the NRC issued PGE a renewed license to operate the ISFSI through the first quarter of 2059. PGE updated its ARO to reflect the estimated costs through this date which increased the Trojan ARO by $69 million as of December 31, 2019. The Company also recorded accretion of $4 million and a reduction of $4 million due to settled liabilities.

Under a settlement agreement reached with the USDOE, the Company receives annual reimbursement from the USDOE for certain costs related to monitoring the ISFSI. Pursuant to this process, the USDOE reimbursed the co-owners $4 million in 2019 for costs incurred in 2018 and $4 million in 2018 for costs incurred in 2017 resulting from USDOE delays in accepting spent nuclear fuel.

Utility Plant represents AROs that have been recognized for the Company's thermal and wind generation sites, and distribution and transmission assets, the disposal of which is governed by environmental regulation. During 2019, the Company recorded an overall increase in utility AROs of $14 million, with the change comprised of revisions in estimated cash flows of $13 million, accretion of $4 million, and a reduction of $3 million due to settled liabilities.

In 2019, the Company recorded an $11 million increase to its ARO related to Colstrip to revise the estimated cash flows associated with remediation of a number of settlement ponds that will require upgrading or closure to meet Montana Department of Environmental Quality regulatory requirements.

Non-utility property primarily represents AROs that have been recognized for portions of unregulated properties leased to third parties. Revisions to estimates for non-utility AROs are not subject to regulatory deferral. As such, additions in non-utility AROs are charged directly to the Statement of Income in the period in which the revisions are probable and reasonably estimable.

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

	Years Ended December 31,	
	2019	**2018**
Balance as of beginning of year	$ 197	$ 167
Liabilities incurred	—	—
Liabilities settled	(9)	(5)
Accretion expense	9	8
Revisions in estimated cash flows	82	27
Balance as of end of year	$ 279	$ 197

Pursuant to regulation, the amortization of Utility Plant AROs is included in Depreciation Expense and in customer prices. Any differences in the timing of recognition of costs for financial reporting and ratemaking purposes are deferred as a regulatory asset or regulatory liability. Recovery of Trojan decommissioning costs is included in PGE's retail prices with an equal amount recorded in Total Utility Operating Expenses.

PGE maintains a separate trust account, Nuclear decommissioning trust in the Comparative Balance Sheet, for funds collected from customers through prices to cover the cost of Trojan decommissioning activities.

The Oak Grove hydro facility and transmission and distribution plant located on public right-of-ways and on certain easements meet the requirements of a legal obligation and will require removal when the plant is no longer in service. An ARO liability is not currently measurable as management believes that these assets will be used in utility operations for the foreseeable future. Removal costs are charged to accumulated asset retirement removal costs, which is included in Regulatory liabilities on PGE's Comparative Balance Sheet.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

NOTE 8: CREDIT FACILITIES

As of December 31, 2019, PGE had a $500 million revolving credit facility scheduled to expire in November 2023. The credit facility allows for unlimited extension requests, provided that lenders with a pro-rata share of more than 50% approve the extension request.

Pursuant to the terms of the agreement, the revolving credit facility may be used for general corporate purposes, as backup for commercial paper borrowings, and to permit the issuance of standby letters of credit. PGE may borrow for one, two, three, or six at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the applicable credit facility. The revolving credit facility contains a provision that requires annual fees based on PGE's unsecured credit ratings, and contains customary covenants and default provisions, including a requirement that limits indebtedness, as defined in the agreement, to 65.0% of total capitalization. As of December 31, 2019, PGE was in compliance with this covenant with a 51.9% debt to total capital ratio.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days, limited to the unused amount of credit under the revolving credit facility.

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

Under the revolving credit facility, as of December 31, 2019, PGE had no borrowings outstanding and there were no commercial paper or letters of credit issued. As a result, the aggregate unused available credit capacity under the revolving credit facility was $500 million.

In addition, PGE has four letter of credit facilities that provide a total capacity of $220 million under which the Company can request letters of credit for original terms not to exceed one year. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these facilities, a total of $55 million of letters of credit were outstanding as of December 31, 2019. 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 7, 2022.

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

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

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

The Company had no short-term borrowings during 2018.

NOTE 9: LONG-TERM DEBT

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

	As of December 31,	
	2019	2018

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

First Mortgage Bonds, rates range from 2.51% to 9.31%, with a weighted average rate of 4.63% in 2019 and 5.01% in 2018, due at various dates through 2050	$	2,510	$	2,390
Pollution Control Revenue Bonds, rates at 5%, due 2033		119		119
Pollution Control Revenue Bonds held by PGE		(21)		(21)
Total long-term debt	$	2,608	$	2,488

First Mortgage Bonds—On April 12, 2019, PGE issued $200 million of 4.30% Series FMBs due in 2049. Proceeds from the transaction were used to repay the $300 million current portion of long-term debt on April 15, 2019.

On October 25, 2019, PGE entered into an agreement to issue $270 million of privately placed FMBs in two tranches, both of which bear interest from their issue date at an annual rate of 3.34%. The first tranche, $110 million, with a maturity in 2049, was issued on October 25, 2019, a portion of which was used to redeem $50 million of 6.75% FMBs that had a maturity date in 2023. The second tranche, $160 million, with a maturity in 2050, was issued and funded November 15, 2019.

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

Pollution Control Revenue Bonds—On March 11, 2020, Portland General Electric Company (the "Company") completed the remarketing of an aggregate principal amount of $118.8 million of Pollution Control Revenue Refunding Bonds (Portland General Electric Company Project) Series 1998, consisting of:

(i) $97.8 million principal amount of City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Portland General Electric Company Project) Series 1998A (the "1998A Bonds"), and

(ii) $21.0 million principal amount of City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Portland General Electric Company Project) Series 1998B (the "1998B Bonds" and, together with the 1998A Bonds, the "Bonds").

The Bonds were originally issued by the City of Forsyth (the "Issuer") in 1998. Pursuant to separate Loan Agreements for each series, dated as of May 1, 1998, as amended and supplemented by separate First Supplemental Loan Agreements dated as of May 1, 2003, and separate Second Supplemental Loan Agreements dated as of May 1, 2009 (collectively, the Loan Agreements), the Issuer loaned the proceeds from the initial issuance of the Bonds to the Company. The proceeds of the Bonds were used by the Company to refinance the Company's undivided partial ownership interest in certain pollution control and solid waste disposal facilities at the coal-fired steam electric generating plant known as Colstrip Project Units 3 and 4 in Rosebud County, Montana (the "Colstrip Plant"). The Company's obligations under the Loan Agreements are secured by first mortgage bonds issued by the Company on May 1, 2003.

The 1998A Bonds and 1998B Bonds will bear interest at a rate of 2.125% and 2.375% per annum, respectively, and mature on May 1, 2033. Interest on the Bonds will be payable semi-annually on each March 1 and September 1, commencing September 1, 2020.

As of December 31, 2019, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:		
2020	$	—
2021		160
2022		—
2023		—
2024		80
Thereafter		2,368
	$	2,608

Name of Respondent Portland General Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

NOTE 10: EMPLOYEE BENEFITS

Pension and Other Postretirement Plans

Defined Benefit Pension Plan—PGE sponsors a non-contributory defined benefit pension plan, which has been closed to new employees since January 1, 2012. No changes were made to the benefits provided to existing participants when the plan was closed to new employees.

The assets of the pension plan are held in a trust and are comprised of equity and debt instruments, all of which are recorded at fair value. Pension plan calculations include several assumptions that are reviewed annually and updated as appropriate.

PGE contributed $62 million to the pension plan in 2019 and $9 million in 2018. PGE does not expect to contribute to the pension plan in 2020.

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. In the third quarter of 2019, PGE announced an amendment to its HRAs and defined dollar medical benefit for non-represented employees, resulting in a $2 million curtailment gain, which has been recorded in Miscellaneous income (expense), net on the Statement of Income.

The assets of these plans are held in voluntary employees' beneficiary association trusts and are comprised of money market funds, equity securities, common and collective trust funds, partnerships/joint ventures, and registered investment companies, all of which are recorded at fair value. Postretirement health and life insurance benefit plan calculations include several assumptions that are reviewed annually by PGE and updated as appropriate, with measurement dates of December 31.

Non-Qualified Benefit Plan—The NQBP in the following tables include obligations for a Supplemental Executive Retirement Plan and a directors pension plan, both of which were closed to new participants in 1997. The NQBP also includes pension make-up benefits for employees that participate in the unfunded Management Deferred Compensation Plan (MDCP). Investments in the NQBP trust, consisting of trust-owned life insurance policies and marketable securities, provide funding for the future requirements of these plans. The assets of such trust are included in the accompanying tables for informational purposes only and are not considered segregated and restricted under current accounting standards. The investments in marketable securities, consisting of money market, bonds, and equity mutual funds, are classified as equity or trading debt securities and recorded at fair value. The measurement date for the NQBP is December 31. For further information regarding these trust investments, see Note 5, Fair Value of Financial Instruments.

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

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

	2019			**2018**		
	NQBP	**Other NQBP**	**Total**	**NQBP**	**Other NQBP**	**Total**
Non-qualified benefit plan trust	$ 17	$ 21	$ 38	$ 16	$ 20	$ 36
Non-qualified benefit plan liabilities	26	79	105	24	81	105

Investment Policy and Asset Allocation—The Board of Directors of PGE appoints an Investment Committee, which is comprised of certain members of management from the Company, and establishes the Company's asset allocation. The Investment Committee is

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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,			
	2019		2018	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Equity securities	64%	65%	65%	67%
Debt securities	36	35	35	33
Total	100%	100%	100%	100%
Other Postretirement Benefit Plans:				
Equity securities	61%	59%	58%	59%
Debt securities	39	41	42	41
Total	100%	100%	100%	100%
Non-Qualified Benefits Plans:				
Equity securities	17%	12%	16%	13%
Debt securities	7	12	10	13
Insurance contracts	76	76	74	74
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, 2019:					
Defined Benefit Pension Plan assets:					
Equity securities—Domestic	$ 49	$ —	$ —	$ —	$ 49
Investments measured at NAV:					
Money market funds	—	—	—	5	5
Collective trust funds	—	—	—	632	632
Private equity funds	—	—	—	9	9

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

	$ 49	$ —	$ —	$ 646	$ 695
Other Postretirement Benefit Plans assets:					
Money market funds	$ 4	$ —	$ —	$ —	$ 4
Equity securities:					
Domestic	—	3	—	—	3
International	9	—	—	—	9
Debt securities—Domestic	—	5	—	—	5
Investments measured at NAV:					
Money market funds	—	—	—	5	5
Collective trust funds	—	—	—	8	8
	$ 13	$ 8	$ —	$ 13	$ 34
As of December 31, 2018:					
Defined Benefit Pension Plan assets:					
Equity securities—Domestic	$ 67	$ —	$ —	$ —	$ 67
Investments measured at NAV:					
Money market funds	—	—	—	5	5
Collective trust funds	—	—	—	463	463
Private equity funds	—	—	—	11	11
	$ 67	$ —	$ —	$ 479	$ 546
Other Postretirement Benefit Plans assets:					
Money market funds	$ 3	$ —	$ —	$ —	$ 3
Equity securities:					
Domestic	—	3	—	—	3
International	8	—	—	—	8
Debt securities—Domestic government	—	5	—	—	5
Investments measured at NAV:					
Money market funds	—	—	—	4	4
Collective trust funds	—	—	—	7	7
	$ 11	$ 8	$ —	$ 11	$ 30

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

An overview of the identification of Level 1, 2, and 3 financial instruments is provided in Note 4, Fair Value of Financial Instruments. The following discussion provides information regarding the methods used in valuation of the various asset class investments held in the pension and other postretirement benefit plan trusts.

Money market funds—PGE invests in money market funds that seek to maintain a stable NAV. These funds invest in high-quality, short-term, diversified money market instruments, short-term treasury bills, federal agency securities, or certificates of deposit. Some of the money market funds held in the trusts are classified as Level 1 instruments as pricing inputs are based on unadjusted prices in an

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

active market. The remaining money market funds are valued at NAV as a practical expedient and are not classified in the fair value hierarchy.

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

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

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

Private equity funds—PGE invests in a combination of primary and secondary fund-of-funds, which hold ownership positions in privately held companies across the major domestic and international private equity sectors, including but not limited to, partnerships, joint ventures, venture capital, buyout, and special situations. Private equity investments are valued at NAV as a practical expedient and are not classified in the fair value hierarchy.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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, 2019 and 2018. Information related to the Other NQBP is not included in the following tables (dollars in millions):

	Defined Benefit Pension Plan		Other Postretirement Be nefits		Non-Qualified Benefit Plans	
	2019	**2018**	**2019**	**2018**	**2019**	**2018**
Benefit obligation:						
As of January 1	$ 811	$ 869	$ 72	$ 78	$ 24	$ 27
Service cost	16	19	2	2	—	—
Interest cost	34	32	3	3	1	1
Participants' contributions	—	—	2	2	—	—
Actuarial loss (gain)	88	(67)	8	(7)	3	(1)
Benefit payments	(42)	(39)	(6)	(6)	(2)	(3)
Administrative expenses	(2)	(3)	—	—	—	—
Plan amendment	—	—	(9)	—	—	—
Curtailment gain	—	—	(1)	—	—	—
As of December 31	$ 905	$ 811	$ 71	$ 72	$ 26	$ 24
Fair value of plan assets:						
As of January 1	$ 546	$ 629	$ 30	$ 33	$ 16	$ 17
Actual return on plan assets	131	(50)	5	(2)	1	(1)
Company contributions	62	9	3	3	2	3
Participants' contributions	—	—	2	2	—	—
Benefit payments	(42)	(39)	(6)	(6)	(2)	(3)
Administrative expenses	(2)	(3)	—	—	—	—
As of December 31	$ 695	$ 546	$ 34	$ 30	$ 17	$ 16
Unfunded position as of December 31	$ (210)	$ (265)	$ (37)	$ (42)	$ (9)	$ (8)
Accumulated benefit plan obligation as of December 31	$ 813	$ 734	N/A	N/A	$ 26	$ 24
Classification in Comparative Balance Sheet:						
Noncurrent asset	$ —	$ —	$ —	$ —	$ 17	$ 16
Current liability	—	—	—	—	(2)	(2)
Noncurrent liability	(210)	(265)	(37)	(42)	(24)	(22)
Net liability	$ (210)	$ (265)	$ (37)	$ (42)	$ (9)	$ (8)
Amounts included in comprehensive income:						
Net actuarial loss (gain)	$ (3)	$ 25	$ 5	$ (4)	$ 3	$ (1)
Net prior service credit	—	—	(9)	—	—	—
Amortization of net actuarial loss	(10)	(17)	—	—	(1)	(1)

Name of Respondent Portland General Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

	$ (13)	$ 8	$ (4)	$ (4)	$ 2	$ (2)
Amounts included in AOCL:*						
Net actuarial loss (gain)	$ 213	$ 226	$ 1	$ (4)	$ 13	$ 11
Prior service cost	—	—	(9)	—	—	—
	$ 213	$ 226	$ (8)	$ (4)	$ 13	$ 11

* Amounts included in AOCL related to the Company's defined benefit pension plan and other postretirement benefits are transferred to Other Regulatory Assets and Other Regulatory Liabilities, respectively, due to the future recoverability from retail customers. Accordingly, as of the Comparative Balance Sheet date, such amounts are included in Regulatory assets.

Net periodic benefit cost consists of the following for the years ended December 31 (in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2019	2018	2019	2018	2019	2018
Service cost	$ 16	$ 19	$ 2	$ 2	$ —	$ —
Interest cost on benefit obligation	34	32	3	3	1	1
Expected return on plan assets	(40)	(42)	(2)	(1)	—	—
Amortization of net actuarial loss	10	17	—	—	1	1
Curtailment gain	—	—	(2)	—	—	—
Net periodic benefit cost	$ 20	$ 26	$ 1	$ 4	$ 2	$ 2

The portion of non-service costs attributable to expense related to the pension and other postretirement benefit plans, is classified as Administrative and General Expenses on the Company's Statement of Income. PGE estimates that $17 million will be amortized from AOCL into net periodic benefit cost in 2020, consisting of a net actuarial loss of $17 million for pension benefits, a net actuarial gain and prior service credit of $1 million for other postretirement benefits and a net actuarial loss of $1 million for non-qualified benefits. Amounts related to the pension and other postretirement benefits are offset with the amortization of the corresponding regulatory asset.

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

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2019	2018	2019	2018	2019	2018
Assumptions used to determine benefit obligations:						
Discount rate	3.43%	4.25%	3.19% - 3.47%	4.10% - 4.26%	3.43%	4.25%
Weighted average rate of compensation increase	3.65%	3.65%	4.58%	4.58%	N/A	N/A
Assumptions used to determine net periodic benefit cost:						

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Discount rate	4.25%	3.65%	3.11% - 4.26%	3.42% - 3.70%	3.43%	3.65%
Weighted average rate of compensation increase	3.65%	3.65%	4.58%	4.58%	N/A	N/A
Long-term rate of return on plan assets	7.00%	7.00%	5.88%	6.20%	N/A	N/A

As of December 31, 2019, there are no liabilities with sensitivity to health care cost trend rates.

Changes in actuarial assumptions can also have a material effect on net periodic pension expense. A 0.25% reduction in the expected long-term rate of return on plan assets, or reduction in the discount rate, would have the effect of increasing the 2019 net periodic pension expense by approximately $2 million.

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					
	2020	2021	2022	2023	2024	2025 - 2029
Defined benefit pension plan	$ 44	$ 44	$ 45	$ 46	$ 46	$ 239
Other postretirement benefits	5	5	5	5	6	20
Non-qualified benefit plans	2	2	2	2	2	11
Total	$ 51	$ 51	$ 52	$ 53	$ 54	$ 270

All of the plans develop expected long-term rates of return for the major asset classes using long-term historical returns, with adjustments based on current levels and forecasts of inflation, interest rates, and economic growth. Also included are incremental rates of return provided by investment managers whose returns are expected to be greater than the markets in which they invest.

401(k) Retirement Savings Plan

PGE sponsors a 401(k) Plan that covers substantially all employees. For eligible employees who are covered by PGE’s defined benefit pension plan, the Company matches employee contributions to the 401(k) Plan up to 6% of the employee’s base pay. For eligible employees who are not covered by PGE’s defined benefit pension plan, the Company contributes 5% of the employee’s base salary, whether or not the employee contributes to the 401(k) Plan, and also matches employee contributions up to 5% of the employee’s base pay.

For the majority of bargaining employees who are subject to the International Brotherhood of Electrical Workers Local 125 agreements the Company contributes an additional 1% of the employee’s base salary, whether or not the employee contributes to the 401(k) Plan.

All contributions are invested in accordance with employees’ elections, limited to investment options available under the 401(k) Plan. PGE made contributions to employee accounts of $25 million in 2019 and $23 million in 2018.

NOTE 11: INCOME TAXES

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

As a result, the Company remeasured its accumulated deferred tax assets in FERC account 190 and recorded a regulatory asset in FERC account 182.3 and remeasured its accumulated deferred tax liabilities in FERC accounts 282 and 283 and recorded a regulatory

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

liability in FERC account 254. These deficient and excess deferred tax items relate primarily to Utility Plant and are deemed “protected” and subject to tax normalization rules that require the benefits to be passed on to customers through future prices over the remaining useful life of the underlying assets to which the deferred income taxes relate. The protected balances in FERC accounts 182.3 and 254 as of December 31, 2019 were $7 million and $304 million, respectively. The protected balances in FERC accounts 182.3 and 254 as of December 31, 2018 were $8 million and $317 million, respectively. These deficient and excess accumulated deferred tax assets and liabilities will be reversed over time using the average rate assumption method (ARAM) and will be recorded to FERC accounts 410.1 and 411.1, respectively. Such reversal was included in customer prices per the Company’s 2019 General Rate Case. The reversal pursuant to ARAM was recorded to 410.1 and 411.1 of $1 million and $10 million, respectively, in both 2019 and 2018.

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

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

	Years Ended December 31,	
	2019	**2018**
Current:		
Federal	$ 9	$ 12
State and local	12	22
	21	34
Deferred:		
Federal	(2)	(15)
State and local	8	(2)
	6	(17)
Income tax expense	$ 27	$ 17

The significant differences between the U.S. federal statutory rate and PGE’s effective tax rate for financial reporting purposes are as follows:

	Years Ended December 31,	
	2019	**2018**
Federal statutory tax rate	21.0%	21.0%
Federal tax credits[1]	(13.4)	(16.7)
State and local taxes, net of federal tax benefit	6.5	6.5
Flow through depreciation and cost basis differences	1.5	1.5
Excess deferred tax reversal[2]	(3.7)	(4.1)
Other	(0.7)	(0.8)
Effective tax rate	11.2%	7.4%

Name of Respondent Portland General Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

(1) Federal tax credits consist primarily of production tax credits (PTCs) earned from Company-owned wind-powered generating facilities. The federal PTCs are earned based on a per-kilowatt hour rate, and as a result, the annual amount of PTCs earned will vary based on weather conditions and availability of the facilities. The PTCs are generated for 10 years from the corresponding facilities' in-service dates. PGE's PTC generation ended or will end at various dates between 2017 and 2024.
(2) The majority of excess deferred income taxes related to remeasurement under the TCJA is subject to Internal Revenue Service (IRS) normalization rules and will be reversed over the remaining regulatory life of the assets using the average rate assumption method.

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

	As of December 31,	
	2019	**2018**
Accumulated Deferred Income Tax Assets		
Employee benefits	$ 120	$ 134
Price risk management	36	42
Regulatory liabilities	22	26
Tax credits	64	52
Depreciation and amortization	315	304
Other	6	22
Total Deferred Income Tax Assets	563	580
Accumulated Deferred Income Tax Liabilities		
Depreciation and amortization	812	815
Regulatory assets	105	116
Price Risk Management	10	6
Other	14	12
Total Deferred Income Tax Liabilities	941	949
Accumulated Deferred Income Tax Liability, net	$ 378	$ 369

As of December 31, 2019, PGE has federal credit carryforwards of $64 million, consisting of PTCs, which will expire at various dates through 2039. PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2019 and 2018 will be realized; accordingly, no valuation allowance has been recorded. As of December 31, 2019, and 2018, PGE had no material unrecognized tax benefits.

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

NOTE 12: EQUITY-BASED PLANS

Employee Stock Purchase Plan

PGE has an employee stock purchase plan (ESPP) under which a total of 625,000 shares of the Company's common stock may be issued. The ESPP permits all eligible employees to purchase shares of PGE common stock through regular payroll deductions, which are limited to 10% of base pay. Each year, employees may purchase up to a maximum of $25,000 in common stock or 1,500 shares (based on fair value on the purchase date), whichever is less. Two six-month offering periods occur annually, January 1 through June 30 and July 1 through December 31, during which eligible employees may contribute toward the purchase of shares of PGE common stock. Purchases occur the last day of the offering period, at a price equal to 95% of the fair value of the stock on the purchase date. As of December 31, 2019, there were 278,098 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, 2019, there were 2,466,470 shares available for future issuance pursuant to the DRIP.

NOTE 13: STOCK-BASED COMPENSATION EXPENSE

Pursuant to the Portland General Electric Company Stock Incentive Plan as amended and restated effective February 13, 2018 (the Plan), the Company may grant a variety of equity-based awards, including restricted stock units (RSUs) with time-based vesting conditions (time-based RSUs) and performance-based vesting conditions (performance-based RSUs), to non-employee directors, officers, or certain key employees. RSU activity is summarized in the following table:

	Units	Weighted Average Grant Date Fair Value
Nonvested units as of December 31, 2017	399,376	$ 37.98
Granted	198,864	37.99
Forfeited	(8,556)	39.73
Vested	(160,771)	36.77
Nonvested units as of December 31, 2018	428,913	38.43
Granted	210,555	49.06
Forfeited	(9,041)	41.68
Vested	(167,037)	37.52
Nonvested units as of December 31, 2019	463,390	43.52

A total of 4,687,500 shares of common stock were registered for issuance under the Plan, of which 2,902,576 shares remain available for future issuance as of December 31, 2019.

Outstanding RSUs provide for the payment of one Dividend Equivalent Right (DER) for each stock unit. Each DER represents an amount equal to dividends paid to shareholders on a share of PGE's common stock and vests on the same schedule as the related RSU. The DERs are settled in shares of PGE common stock valued either at the closing stock price on the vesting date (for performance-based RSUs) or dividend payment date (for all other grants).

Time-based RSUs generally vest over a period of up to three years from the grant date. The fair value of time-based RSUs is measured based on the closing price of PGE common stock on the date of grant and charged to compensation expense on a straight-line basis over the requisite service period for the entire award. The total value of time-based RSUs vested was $1 million for the years ended December 31, 2019 and 2018.

Performance-based RSUs vest based on the extent to which performance goals are met at the end of a three-year performance period, subject to adjustment by the Compensation and Human Resources Committee of PGE's Board of Directors. The number of RSUs that may vest under grants awarded in 2018 and 2017 is based on two equally-weighted metrics: i) actual return on equity relative to allowed return on equity; and ii) a relative total shareholder return (TSR) of PGE's common stock as compared to an index of peer companies during the performance period. Based on the attainment of the goals, the number of RSUs that vest can range from zero to 175% of the RSUs granted. The number of RSUs that may vest under grants awarded in 2019 is based on three equally-weighted metrics: i) actual return on equity relative to allowed return on equity; ii) average EPS growth; and iii) power supply portfolio

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

decarbonization—and relative TSR as a modifier to the total of the three equally-weighted metrics. Based on the attainment of the goals, the number of RSUs that vest can range from zero to 200% of the RSUs granted.

For return on equity, average EPS growth and power supply portfolio decarbonization 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:

	2019	2018
Risk-free interest rate	2.5%	2.4%
Expected term (in years)	3.0	3.0
Volatility	14.8% - 74.5%	14.7% - 21.8%

There is no expected dividend yield used in the valuation, as it is assumed that all dividends distributed during the performance period are reinvested in the Company's underlying stock. The fair value of performance-based RSUs is charged to compensation expense on a straight-line basis over the requisite service period for the entire award based on the number of shares expected to vest. Stock-based compensation expense was calculated assuming the attainment of performance goals that would allow the weighted average vesting of 123.0%, 86.6%, and 89.1% of awarded performance-based RSUs for the respective 2019, 2018, and 2017 grants, with an estimated 5% forfeiture rate.

The total value of performance-based RSUs vested was $7 million for the year ended December 31, 2019 and $4 million for 2018.

Stock-based compensation, included in Administrative and General Expenses in the Statement of Income, was $9 million for the year ended December 31, 2019 and $5 million for 2018. Such amounts differ from those reported in Other Paid-in Capital Stock-based compensation due primarily to the impact from the income tax payments made on behalf of employees. The Company withholds a portion of the vested shares for the payment of income taxes on behalf of the employees. Not included in Administrative and General Expenses in the Statement of Income, is the net impact from these income tax payments, partially offset by the issuance of DERs, resulting in a charge to Stockholder equity of $2 million in 2019 and $2 million in 2018.

As of December 31, 2019, unrecognized stock-based compensation expense was $10 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, 2019, PGE's estimated future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2020	2021	2022	2023	2024	Thereafter	Total
Capital and other purchase commitments	$ 393	$ 130	$ 14	$ 4	$ 1	$ 56	$ 598
Purchased Power:							
Electricity purchases	193	189	220	219	215	2,327	3,363
Capacity contracts	—	9	9	9	9	9	45
Public utility districts	16	15	13	13	12	50	119
Natural gas	59	45	40	38	42	603	827
Coal and transportation	27	27	27	27	27	27	162
Total	$ 688	$ 415	$ 323	$ 310	$ 306	$ 3,072	$ 5,114

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Capital and other purchase commitments—Certain commitments have been made for 2020 and beyond that include those related to hydro licenses, upgrades to generation, distribution, and transmission facilities, information systems, and system maintenance work. Termination of these agreements could result in cancellation charges.

Electricity purchases and Capacity contracts—PGE has power purchase agreements with counterparties, which expire at varying dates through 2051, and power capacity contracts through 2025.

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

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

Under the Grant County agreements, the Company is required to pay its proportionate share of the operating and debt service costs of the hydroelectric projects whether they are operable or not. Under the Douglas County agreement, the Company is required to make monthly payments for capacity that will not vary with annual project generation provided to PGE. The Company has estimated the capacity payments, which are subject to annual adjustments based on Douglas County's loads, and included the estimated amounts in the table above. The future minimum payments for the PUDs in the preceding table reflect the principal and capacity payments only and do not include interest, operation, or maintenance expenses.

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

	Capacity Charges and Revenue Bonds as of December 31, 2019	PGE's Average Share as of December 31, 2019		Contract Expiration	Total PGE Contract Costs		
		Output	Capacity		2019	2018	2017
			(in MW)				
Priest Rapids and Wanapum	$ 1,302	8.6%	163	2052	$ 21	$ 17	$ 16
Wells	651	13.6	98	2028	16	11	11

The agreements for Priest Rapids, Wanapum, and Wells provide that, should any other purchaser of output default on payments as a result of bankruptcy or insolvency, PGE would be allocated a pro-rata share of the output and operating and debt service costs of the defaulting purchaser. For Wells, PGE would be responsible for a pro-rata portion of the defaulting purchaser's share with no limitation, regardless of the reason for any default. For Priest Rapids and Wanapum, PGE would be allocated up to a cumulative maximum that would not adversely affect the tax-exempt status of any of the public utility district's outstanding debt for the portion of the project that benefits tax-exempt purchasers.

Natural gas—PGE has contracts for the purchase and transportation of natural gas from domestic and Canadian sources for its natural gas-fired generating facilities.

Coal and transportation—PGE has coal and related rail transportation agreements with take-or-pay provisions related to Boardman that expire in December 2020. The Company also has a coal agreement with take-or-pay provisions related to Colstrip that expires in December 2025.

Guarantees

PGE enters into financial agreements and power and natural gas purchase and sale agreements that include indemnification provisions relating to certain claims or liabilities that may arise relating to the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. PGE periodically evaluates the likelihood of incurring costs under such indemnities based on the Company's historical experience and the evaluation of the specific indemnities. As of December 31, 2019, 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, 2019 are immaterial. PGE has lease agreements with lease and non-lease components, which are accounted for separately.

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

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

	2019
Operating lease cost	$ 7
Finance lease cost:	
Amortization of right-of-use assets	$ 3
Interest on lease liabilities	6
Total finance lease cost	$ 9
Variable lease cost	$ 19

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

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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

Lease term and discount rates were as follows:

	December 31, 2019
Weighted Average Remaining Lease Term	
Operating leases	24 years
Finance leases	29 years
Weighted Average Discount Rate	
Operating leases	3.5%
Finance leases	7.3%

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

As of December 31, 2019, maturities of lease liabilities were as follows (in millions):

	Operating Leases	Finance Leases
2020	$ 8	$ 16
2021	8	16
2022	8	16
2023	8	14
2024	7	14
Thereafter	46	235
Total lease payments	85	311
Less imputed interest	(34)	(160)
Total	$ 51	$ 151

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

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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

2018 Lease Obligations

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

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

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

As of December 31, 2018, a capital lease asset of $57 million was reflected within Utility Plant and accumulated amortization of such assets of $8 million was reflected within Accumulated Provision for Depreciation, Amortization and Depletion in the Comparative Balance Sheet. The present value of the future minimum lease payments due under the agreement included $2 million within Obligations Under Capital Leases - Current and $47 million in Other noncurrent liabilities on the Comparative Balance Sheet. For ratemaking purposes capital leases are treated as operating leases; therefore, in accordance with the accounting rules for regulated operations, the amortization of the leased asset is based on the rental payments recovered from customers. Amortization of the leased asset of $3 million and interest charges of $4 million was recorded to Purchased Power in the Statement of Income through December 31, 2018. Pursuant to the adoption of the new lease accounting standard, Topic 842, PGE derecognized the capital lease obligation and related capital lease asset as it no longer met the definition of a lease.

Build-to-suit—PGE entered into a 30-year lease agreement with a local natural gas company, NW Natural, to expand their natural gas

Name of Respondent Portland General Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2019/Q4

storage facilities, including the development of an underground storage reservoir and construction of a new compressor station and 13-miles of pipeline, which are collectively designed to provide no-notice storage and transportation services to PW1, PW2, and Beaver. Construction of the expansion project was completed in the second quarter of 2019 at a cost of $149 million. Due to the level of PGE's involvement during the construction period, the Company was deemed to be the owner of the assets for accounting purposes during the construction period. As a result, PGE recorded $131 million to Construction Work In Progress within Net Utility Plant and a corresponding liability for the same amount to Deferred Credits in the Comparative Balance Sheet as of December 31, 2018. Pursuant to the adoption of the new lease accounting standard, Topic 842, PGE derecognized the build-to-suit assets and liabilities on January 1, 2019, as they are no longer considered to meet the build-to-suit criteria under the new standard. For additional information regarding the new lease accounting standard, see Note 2, Summary of Significant Accounting Policies.

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

Operating leases—PGE has various operating leases associated with leases of land, support facilities, and power purchase agreements that rely on identified plant that expire in various years, extending through 2096. Rent expense was $7 million in 2018. Contingent rents related to power purchase agreements was $14 million in 2018. Sublease income was $4 million in 2018.

NOTE 16: JOINTLY-OWNED PLANT

As of December 31, 2019, PGE had the following investments in jointly-owned plant (dollars in millions):

	PGE Share	In-service Date	Plant In-service	Accumulated Depreciation*	Construction Work In Progress
Boardman	90.00%	1,980	$ 683	$ 644	$ —
Colstrip	20.00	1,986	550	375	14
Pelton/Round Butte	66.67	1,958 / 1,964	265	78	6
Total			$ 1,498	$ 1,097	$ 20

* Excludes AROs and accumulated asset retirement removal costs.

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

NOTE 17: CONTINGENCIES

PGE is subject to legal, regulatory, and environmental proceedings, investigations, and claims that arise from time to time in the ordinary course of its business. Contingencies are evaluated using the best information available at the time the financial statements are prepared. Legal costs incurred in connection with loss contingencies are expensed as incurred. The Company may seek regulatory recovery of certain costs that are incurred in connection with such matters, although there can be no assurance that such recovery would be granted.

Loss contingencies are accrued, and disclosed if material, when it is probable that an asset has been impaired, or a liability incurred, as of the financial statement date and the amount of the loss can be reasonably estimated. If a reasonable estimate of probable loss cannot be determined, a range of loss may be established, in which case the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate.

A loss contingency will also be disclosed when it is reasonably possible that an asset has been impaired, or a liability incurred, if the estimate or range of potential loss is material. If a probable or reasonably possible loss cannot be reasonably estimated, then the Company: i) discloses an estimate of such loss or the range of such loss, if the Company is able to determine such an estimate; or ii) discloses that an estimate cannot be made and the reasons.

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

PGE evaluates, on a quarterly basis, developments in such matters that could affect the amount of any accrual, as well as the likelihood of developments that would make a loss contingency both probable and reasonably estimable. The assessment as to whether a loss is probable or reasonably possible, and as to whether such loss or a range of such loss is estimable, often involves a series of complex judgments about future events. Management is often unable to estimate a reasonably possible loss, or a range of loss, particularly in cases in which: i) the damages sought are indeterminate or the basis for the damages claimed is not clear; ii) the proceedings are in the early stages; iii) discovery is not complete; iv) the matters involve novel or unsettled legal theories; v) significant facts are in dispute; vi) a large number of parties are represented (including circumstances in which it is uncertain how liability, if any, would be shared among multiple defendants); or vii) a wide range of potential outcomes exist. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including any possible loss, fine, penalty, or business impact.

EPA Investigation of Portland Harbor

An investigation by the United States Environmental Protection Agency (EPA) of a segment of the Willamette River known as Portland Harbor that began in 1997 revealed significant contamination of river sediments. The EPA subsequently included Portland Harbor on the National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act as a federal Superfund site. PGE was included among the Potentially Responsible Parties (PRPs) as it has historically owned or operated property near the river.

In 2008, the EPA requested information from various parties, including PGE, concerning additional properties in or near the original segment of the river under investigation, as well as several miles beyond. Subsequently, the EPA has listed additional PRPs, which now number over one hundred.

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

The EPA finalized the feasibility study, along with the remedial investigation, and the results provided the framework for the EPA to determine a clean-up remedy for Portland Harbor that was documented in a Record of Decision (ROD) issued in 2017. The ROD outlined the EPA's selected remediation plan for clean-up of the Portland Harbor site, which has an undiscounted estimated total cost of $1.7 billion, comprised of $1.2 billion related to remediation construction costs and $0.5 billion related to long-term operation and maintenance costs. Remediation construction costs were estimated to be incurred over a 13-year period, with long-term operation and maintenance costs estimated to be incurred over a 30-year period from the start of construction. The EPA acknowledged the estimated costs are based on data that was outdated and that pre-remedial design sampling was necessary to gather updated baseline data to better refine the remedial design and estimated cost. A small group of PRPs performed pre-remedial design sampling to update baseline data and submitted the data in an updated evaluation report to the EPA for review. The evaluation report concluded that the conditions of the Portland Harbor Superfund site have improved substantially over the past ten years. In response, the EPA indicated that while it would use the data to inform implementation of the ROD, the EPA's conclusions remained materially unchanged. EPA is currently seeking parties to sign up to perform remedial design.

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

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

In cases in which injuries to natural resources have occurred as a result of releases of hazardous substances, federal and state natural resource trustees may seek to recover for damages at such sites, which are referred to as Natural Resource Damages (NRD). The EPA does not manage NRD assessment activities but does provide claims information and coordination support to the NRD trustees. NRD assessment activities are typically conducted by a Council made up of the trustee entities for the site. The Portland Harbor NRD trustees consist of the National Oceanic and Atmospheric Administration, the U.S. Fish and Wildlife Service, the state of Oregon, the Confederated Tribes of the Grand Ronde Community of Oregon, the Confederated Tribes of Siletz Indians, the Confederated Tribes of the Umatilla Indian Reservation, the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS), and the Nez Perce Tribe.

The NRD trustees may seek to negotiate legal settlements or take other legal actions against the parties responsible for the damages. Funds from such settlements must be used to restore injured resources and may also compensate the trustees for costs incurred in assessing the damages. The Company believes that PGE's portion of NRD liabilities related to Portland Harbor will not have a material impact on its results of operations, financial position, or cash flows.

The impact of such costs to the Company's results of operations is mitigated by the Portland Harbor Environmental Remediation Account (PHERA) mechanism. As approved by the OPUC in 2017, the PHERA allows the Company to defer and recover incurred environmental expenditures related to the Portland Harbor Superfund Site through a combination of third-party proceeds, such as insurance recoveries, and if necessary, through customer prices. The mechanism established annual prudency reviews of environmental expenditures and third-party proceeds. Annual expenditures in excess of $6 million, excluding expenses related to contingent liabilities, are subject to an annual earnings test and would be ineligible for recovery to the extent PGE's actual regulated return on equity exceeds its return on equity as authorized by the OPUC in PGE's most recent general rate case. 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.

Trojan Investment Recovery Class Actions

In 1993, PGE closed the Trojan nuclear power plant (Trojan) and sought full recovery of, and a rate of return on, its Trojan costs in a general rate case filing with the OPUC. In 1995, the OPUC issued a general rate order that granted the Company recovery of, and a rate of return on, 87% of its remaining investment in Trojan.

Numerous challenges and appeals were subsequently filed in various state courts on the issue of the OPUC's authority under Oregon law to grant recovery of, and a return on, the Trojan investment. In 2007, following several appeals by various parties, the Oregon Court of Appeals issued an opinion that remanded the matter to the OPUC for reconsideration.

In 2003, in two separate proceedings, lawsuits were filed against PGE on behalf of two classes of electric service customers: i) Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company, Marion County Circuit Court (Circuit Court); and ii) Morgan v. Portland General Electric Company, Marion County Circuit Court. The class action lawsuits seek damages totaling $260 million, plus interest, as a result of the Company's inclusion, in prices charged to customers, of a return on its investment in Trojan.

In 2006, the Oregon Supreme Court (OSC) issued a ruling ordering the abatement of the class action proceedings. The OSC concluded that the OPUC had primary jurisdiction to determine what, if any, remedy could be offered to PGE customers, through price reductions or refunds, for any amount of return on the Trojan investment that the Company collected in prices.

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

In 2015, based on a motion filed by PGE, the Marion County Circuit Court lifted the abatement on the class action proceedings and heard oral argument on the Company's motion for Summary Judgment. In 2016, the Circuit Court entered a general judgment that granted the Company's motion for Summary Judgment and dismissed all claims by the plaintiffs. The plaintiffs subsequently appealed the Circuit Court dismissal to the Court of Appeals for the state of Oregon.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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

PGE believes that the 2014 OSC decision, the decisions of the Circuit Court and the Court of Appeals that followed have reduced the risk of any loss to the Company beyond the amounts previously recorded and refunds discussed above. However, because the class actions remain subject to a potential petition for review to the OSC, management believes that it is reasonably possible that such a loss to the Company could result. As these matters involve unsettled legal theories and have a broad range of potential outcomes, sufficient information is currently not available to determine the amount of any such loss.

Deschutes River Alliance Clean Water Act Claims

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

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

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

In August 2018, the U.S. District Court of the District of Oregon (District Court) denied DRA’s motions for partial summary judgment and granted PGE’s and CTWS’s cross-motions for summary judgment, ruling in favor of PGE and CTWS. The District Court found that DRA had not shown a genuine dispute of material fact sufficient to support its contention that PGE and CTWS were operating the Project in violation of the CWA, and accordingly dismissed the case.

In October 2018, DRA filed an appeal, and PGE and CTWS filed cross-appeals, to the Ninth Circuit Court of Appeals. In December 2019, the Court of Appeals closed the case and vacated the briefing schedule, pending ongoing discussions among the parties. On March 10, 2020, the Court of Appeals reopened the case and reset the briefing schedule.

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

Other Matters

PGE is subject to other regulatory, environmental, and legal proceedings, investigations, and claims that arise from time to time in the ordinary course of business, which may result in judgments against the Company. Although management currently believes that resolution of such matters, individually and in the aggregate, will not have a material impact on its financial position, results of operations, or cash flows, these matters are subject to inherent uncertainties, and management’s view of these matters may change in the future.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				(7,905,934)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				1,474,308
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				1,474,308
5	Balance of Account 219 at End of Preceding Quarter/Year				(6,431,626)
6	Balance of Account 219 at Beginning of Current Year				(6,431,626)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(3,183,476)
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				(3,183,476)
10	Balance of Account 219 at End of Current Quarter/Year				(9,615,102)

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	(808)		(7,906,742)	[redacted]	
2			1,474,308		
3					
4			1,474,308	211,890,700	213,365,008
5	(808)		(6,432,434)	[redacted]	
6	(808)		(6,432,434)		
7			(3,183,476)		
8					
9			(3,183,476)	213,848,540	210,665,064
10	(808)		(9,615,910)	[redacted]	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	9,843,512,321	9,843,512,321
4	Property Under Capital Leases	201,053,713	201,053,713
5	Plant Purchased or Sold		
6	Completed Construction not Classified	1,094,485,883	1,094,485,883
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	11,139,051,917	11,139,051,917
9	Leased to Others		
10	Held for Future Use	7,526,471	7,526,471
11	Construction Work in Progress	329,538,575	329,538,575
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	11,476,116,963	11,476,116,963
14	Accum Prov for Depr, Amort, & Depl	5,280,409,859	5,280,409,859
15	Net Utility Plant (13 less 14)	6,195,707,104	6,195,707,104
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	4,914,258,659	4,914,258,659
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	366,151,200	366,151,200
22	Total In Service (18 thru 21)	5,280,409,859	5,280,409,859
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	5,280,409,859	5,280,409,859

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	194,056,988	1,207,828
4	(303) Miscellaneous Intangible Plant	520,875,690	42,868,915
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	714,932,678	44,076,743
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	4,161,715	
9	(311) Structures and Improvements	258,766,726	188,474
10	(312) Boiler Plant Equipment	613,490,822	837,222
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	188,750,319	
13	(315) Accessory Electric Equipment	55,276,806	-9,423
14	(316) Misc. Power Plant Equipment	14,882,109	134,022
15	(317) Asset Retirement Costs for Steam Production	68,024,700	11,253,071
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,203,353,197	12,403,366
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	6,053,903	
28	(331) Structures and Improvements	74,776,754	3,640,021
29	(332) Reservoirs, Dams, and Waterways	376,582,669	6,498,395
30	(333) Water Wheels, Turbines, and Generators	69,502,087	1,768,687
31	(334) Accessory Electric Equipment	19,102,191	1,013,281
32	(335) Misc. Power PLant Equipment	2,551,798	22,136,695
33	(336) Roads, Railroads, and Bridges	13,364,041	2,027,859
34	(337) Asset Retirement Costs for Hydraulic Production	5,128	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	561,938,571	37,084,938
36	D. Other Production Plant		
37	(340) Land and Land Rights	48,946	28,854,631
38	(341) Structures and Improvements	259,925,642	3,048,946
39	(342) Fuel Holders, Products, and Accessories	211,112,025	155,100,592
40	(343) Prime Movers		
41	(344) Generators	2,366,956,822	28,148,348
42	(345) Accessory Electric Equipment	120,904,011	965,987
43	(346) Misc. Power Plant Equipment	20,861,577	2,355,322
44	(347) Asset Retirement Costs for Other Production	16,698,437	5,877,916
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	2,996,507,460	224,351,742
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,761,799,228	273,840,046

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	13,300,374	
49	(352) Structures and Improvements	25,880,787	1,508,481
50	(353) Station Equipment	370,672,259	1,638,530
51	(354) Towers and Fixtures	48,814,373	9,955
52	(355) Poles and Fixtures	38,517,315	7,618,484
53	(356) Overhead Conductors and Devices	87,872,358	20,763,934
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	286,332	
57	(359.1) Asset Retirement Costs for Transmission Plant	34,109	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	585,377,907	31,539,384
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	22,403,484	326,980
61	(361) Structures and Improvements	48,371,835	1,817,614
62	(362) Station Equipment	615,694,452	64,783,567
63	(363) Storage Battery Equipment	384,933	8,258
64	(364) Poles, Towers, and Fixtures	433,213,879	31,606,065
65	(365) Overhead Conductors and Devices	692,225,410	33,103,472
66	(366) Underground Conduit	24,483,916	5,031,713
67	(367) Underground Conductors and Devices	819,262,292	88,304,122
68	(368) Line Transformers	443,796,805	26,068,911
69	(369) Services	469,740,515	29,715,514
70	(370) Meters	167,513,144	20,918,438
71	(371) Installations on Customer Premises	376,133	1,373,580
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	97,712,189	19,738,897
74	(374) Asset Retirement Costs for Distribution Plant	476,732	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,835,655,719	322,797,131
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	13,216,984	4,500
87	(390) Structures and Improvements	140,614,699	11,476,148
88	(391) Office Furniture and Equipment	152,783,807	17,029,639
89	(392) Transportation Equipment	78,048,616	4,085,984
90	(393) Stores Equipment	3,775,960	409,466
91	(394) Tools, Shop and Garage Equipment	21,388,472	2,843,877
92	(395) Laboratory Equipment	9,485,292	81
93	(396) Power Operated Equipment	36,610,774	14,013,732
94	(397) Communication Equipment	154,307,654	24,425,384
95	(398) Miscellaneous Equipment	1,035,022	236,898
96	SUBTOTAL (Enter Total of lines 86 thru 95)	611,267,280	74,525,709
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	65,289	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	611,332,569	74,525,709
100	TOTAL (Accounts 101 and 106)	10,509,098,101	746,779,013
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	10,509,098,101	746,779,013

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

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

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			195,264,816		3
579,743	-626		563,164,236		4
579,743	-626		758,429,052		5
					6
					7
	-90		4,161,625		8
	-90	-54,621	258,900,489		9
17,645	-89		614,310,310		10
					11
	-90		188,750,229		12
	-90		55,267,293		13
	-90		15,016,041		14
	-3,297,200		75,980,571		15
17,645	-3,297,739	-54,621	1,212,386,558		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			6,053,903		27
43,431		5,696,177	84,069,521		28
328,711		-23,983,212	358,769,141		29
387,356		6,111,289	76,994,707		30
689,696		12,175,758	31,601,534		31
	-3,373,046		21,315,447		32
			15,391,900		33
			5,128		34
1,449,194	-3,373,046	12	594,201,281		35
					36
	-1,943,539		26,960,038		37
	3,240	-32,874,724	230,103,104		38
	-59,767,272	-10,561,788	295,883,557		39
					40
348,434	-406,631	11,979,593	2,406,329,698		41
481,444		-251,587	121,136,967		42
		20,864,085	44,080,984		43
			22,576,353		44
829,878	-62,114,202	-10,844,421	3,147,070,701		45
2,296,717	-68,784,987	-10,899,030	4,953,658,540		46

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
		3,969,311	17,269,685		48
456,025		3,340,789	30,274,032		49
206,092		127,667,570	499,772,267		50
			48,824,328		51
		37,228,624	83,364,423		52
		60,801,814	169,438,106		53
					54
					55
			286,332		56
			34,109		57
662,117		233,008,108	849,263,282		58
					59
156,926		-3,279,314	19,294,224		60
248,158		-3,615,201	46,326,090		61
3,171,874		-117,625,910	559,680,235		62
			393,191		63
7,527,201		-37,226,953	420,065,790		64
3,639,372		-57,629,701	664,059,809		65
			29,515,629		66
8,901	-331,292	-2	907,226,219		67
		-2	469,865,714		68
757,959		-3,314,504	495,383,566		69
3,144,812		-2	185,286,768		70
			1,749,713		71
					72
197,833			117,253,253		73
			476,732		74
18,853,036	-331,292	-222,691,589	3,916,576,933		75
					76
					77
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					80
					81
					82
					83
					84
					85
172,086	-310,392	-3,116,653	9,622,353		86
253,865	-514,900	121,966	151,444,048		87
10,004,049	-12,579	710,951	160,507,769		88
3,677,338			78,457,262		89
307,542			3,877,884		90
1,138,965			23,093,384		91
584,301			8,901,072		92
5,993,737			44,630,769		93
65,508	-90	561,558	179,228,998		94
	319	23,043	1,295,282		95
22,197,391	-837,642	-1,699,135	661,058,821		96
					97
			65,289		98
22,197,391	-837,642	-1,699,135	661,124,110		99
44,589,004	-69,954,547	-2,281,646	11,139,051,917		100
					101
					102
					103
44,589,004	-69,954,547	-2,281,646	11,139,051,917		104

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Schedule Page: 204 Line No.: 32 Column: c

$22M relates to additions of capitalized lease assets.

Schedule Page: 204 Line No.: 32 Column: e

Includes amortization of capitalized lease assets.

Schedule Page: 204 Line No.: 37 Column: c

$29M relates to additions of capitalized lease assets.

Schedule Page: 204 Line No.: 37 Column: e

Includes amortization of capitalized lease assets.

Schedule Page: 204 Line No.: 39 Column: c

$152M relates to additions of capitalized lease assets.

Schedule Page: 204 Line No.: 39 Column: e

Includes de-recognition of Carty Lateral capital lease asset. Carty Lateral does not qualify as a capitalized lease under new accounting guidance effective January 1, 2019.

Schedule Page: 204 Line No.: 41 Column: c

$2M relates to additions of capitalized lease assets.

Schedule Page: 204 Line No.: 41 Column: e

Includes amortization of capitalized lease assets.

Schedule Page: 204 Line No.: 87 Column: c

$6M relates to additions of capitalized lease assets.

Schedule Page: 204 Line No.: 87 Column: e

Includes amortization of capitalized lease assets.

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

On September 6, 2019, PGE filed a petition for declaratory order in Docket No. EL19-95-00 seeking to reclassify certain 57 kV and 115 kV facilities from distribution to transmission. The case was held in abeyance, pending the outcome of a parallel proceeding before the OPUC.

On November 22, 2019, PGE filed a motion to supplement the petition to include the OPUC's decision in Docket No. UM 2031, which granted reclassification of a subset of the facilities. The stipulation in OPUC Order No. 19-400 identified four characteristics that reflect the reclassification:

A. Radial lines both to distribution and to customers tend to be distribution, but radial generation tie facilities tend to be transmission for accounting purposes but should be classified as production for ratemaking purposes;

B. Non-radial line segments of 100 kV or higher voltage tend to be transmission;

C. Transformers with a secondary voltage under 100 kV tend to be distribution; and

D. Substation assets (e.g. circuit breakers) that are part of the path that connect the transmission line segments, or equipment associated with transformers with a secondary voltage higher than 100 kV, are considered transmission

The FERC approved the reclassification of identified facilities on December 31, 2019. As a result, PGE reclassified certain 115 kV facilities totaling $223,287,442 from distribution to transmission.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
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41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Damascus, Clackamas County, OR	2007	Future	543,591
3	Sewell, Washington County, OR	2008	Future	2,869,529
4	Sewell Easement, Washington County, OR	2009	Future	331,186
5	Evergreen, Washington County, OR	2019	Future	3,600,000
6				
7	Other Land and Land Rights	Various	Various	182,165
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
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33				
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36				
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41				
42				
43				
44				
45				
46				
47	Total			7,526,471

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	Harborton Reliability Project	37,708,733
2	Repower Faraday Units 1-5	34,748,303
3	Build Integrated Operations Center	28,455,538
4	Blue Lake Substation Upgrade	26,196,691
5	Substation Communication Upgrade	24,965,674
6	Wheatridge Renewable Energy Facility	17,331,289
7	Colstrip Coal Capital Project	13,461,228
8	Rock Creek Substation Construction	12,646,409
9	Build Evergreen Substation	12,297,181
10	Round Butte Transmission Upgrades	11,906,470
11	Roseway Substation Expansion	9,219,571
12	Upgrade Physical Access Control System	6,334,588
13	Remote Imaging Project	6,141,962
14	West Side Hydro Structural/Reliability Upgrade	5,159,304
15	Advanced Distribution Management System Upgrade	4,976,966
16	Hydro Control System Upgrade	4,546,929
17	Distribution Automation Project	4,257,055
18	Willbridge Substation Conversion	3,516,700
19	Brookwood Substation Conversion	3,513,662
20	St. Mary's West Substation System Protection Upgrade	3,202,244
21	Pelton Round Butte Mitigation Enhancement Fund	3,067,630
22	Residential Flexible Pricing Implementation	2,861,347
23	River District Infrastructure - Install Vaults and Conduits	2,685,962
24	River Mill Unit 3 Rewind	2,605,427
25	Human Resources System Implementation	2,256,015
26	Field Area Network Project	2,154,362
27	Centennial Substation Upgrades	2,123,268
28	South Milliken Distribution Line Rebuild	2,057,044
29	Stephens Substation Conversion	1,935,298
30	Clackamas Protection Mitigation Enhancement	1,854,468
31	Distributed Control System Software Upgrade	1,753,010
32	Arleta-Holgate Conversion	1,639,408
33	Carty Water Treatment System Upgrade	1,475,949
34	Gresham Substation Rebuild	1,378,689
35	Orenco Substation Rebuild	1,113,056
36	Replace or Rewind Failed Transformers	1,079,671
37	Electric Vehicle Charging Station Network Expansion	1,047,330
38	Verint Voice Recording Tool Replacement	1,003,443
39		
40		
41	Minor Projects, <$1 million represents 8% of the Total CWIP Balance	24,860,701
42		
43	TOTAL	329,538,575

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Schedule Page: 216 Line No.: 7 Column: b

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

Schedule Page: 216 Line No.: 21 Column: b

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	4,638,743,404	4,638,743,404		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	307,699,071	307,699,071		
4	(403.1) Depreciation Expense for Asset Retirement Costs	6,887,698	6,887,698		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	5,457,228	5,457,228		
7	Other Clearing Accounts	62,409	62,409		
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	320,106,406	320,106,406		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	44,009,264	44,009,264		
13	Cost of Removal	3,866,818	3,866,818		
14	Salvage (Credit)	3,179,540	3,179,540		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	44,696,542	44,696,542		
16	Other Debit or Cr. Items (Describe, details in footnote):	105,391	105,391		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,914,258,659	4,914,258,659		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,020,042,602	1,020,042,602		
21	Nuclear Production				
22	Hydraulic Production-Conventional	258,144,354	258,144,354		
23	Hydraulic Production-Pumped Storage				
24	Other Production	876,176,986	876,176,986		
25	Transmission	370,161,400	370,161,400		
26	Distribution	2,110,382,439	2,110,382,439		
27	Regional Transmission and Market Operation				
28	General	279,350,878	279,350,878		
29	TOTAL (Enter Total of lines 20 thru 28)	4,914,258,659	4,914,258,659		

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	2019/Q4

FOOTNOTE DATA

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

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

Schedule Page: 219 Line No.: 25 Column: c

On September 6, 2019, PGE filed a petition for declaratory order in Docket No. EL19-95-00 seeking to reclassify certain 57 kV and 115 kV facilities from distribution to transmission. The case was held in abeyance, pending the outcome of a parallel proceeding before the OPUC.

On November 22, 2019, PGE filed a motion to supplement the petition to include the OPUC's decision in Docket No. UM 2031, which granted reclassification of a subset of the facilities. The stipulation in OPUC Order No. 19-400 identified four characteristics that reflect the reclassification:

A. Radial lines both to distribution and to customers tend to be distribution, but radial generation tie facilities tend to be transmission for accounting purposes but should be classified as production for ratemaking purposes;

B. Non-radial line segments of 100 kV or higher voltage tend to be transmission;

C. Transformers with a secondary voltage under 100 kV tend to be distribution; and

D. Substation assets (e.g. circuit breakers) that are part of the path that connect the transmission line segments, or equipment associated with transformers with a secondary voltage higher than 100 kV, are considered transmission

The FERC approved the reclassification of identified facilities on December 31, 2019. As a result, PGE reclassified $113,159,805 of accumulated depreciation related to certain 115 kV facilities from distribution to transmission.

Schedule Page: 219 Line No.: 26 Column: c

On September 6, 2019, PGE filed a petition for declaratory order in Docket No. EL19-95-00 seeking to reclassify certain 57 kV and 115 kV facilities from distribution to transmission. The case was held in abeyance, pending the outcome of a parallel proceeding before the OPUC.

On November 22, 2019, PGE filed a motion to supplement the petition to include the OPUC's decision in Docket No. UM 2031, which granted reclassification of a subset of the facilities. The stipulation in OPUC Order No. 19-400 identified four characteristics that reflect the reclassification:

E. Radial lines both to distribution and to customers tend to be distribution, but radial generation tie facilities tend to be transmission for accounting purposes but should be classified as production for ratemaking purposes;

F. Non-radial line segments of 100 kV or higher voltage tend to be transmission;

G. Transformers with a secondary voltage under 100 kV tend to be distribution; and

H. Substation assets (e.g. circuit breakers) that are part of the path that connect the

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

transmission line segments, or equipment associated with transformers with a secondary voltage higher than 100 kV, are considered transmission

The FERC approved the reclassification of identified facilities on December 31, 2019. As a result, PGE reclassified $113,159,805 of accumulated depreciation related to certain 115 kV facilities from distribution to transmission.

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	121 SW Salmon Street Corporation			
2	Common Stock	04/01/75		1,000
3	Equity in Earnings			77,778,996
4	Sub - TOTAL			77,779,996
5				
6	Salmon Springs Hospitality Group			
7	Common Stock	04/09/98		10,000
8	Equity in Earnings			22,209
9	Sub - TOTAL			32,209
10				
11				
12				
13				
14				
15				
16				
17				
18				
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31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	77,812,205

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		1,000		2
2,373,721	-274,848	79,877,869		3
2,373,721	-274,848	79,878,869		4
				5
				6
		10,000		7
192,785	-200,000	14,994		8
192,785	-200,000	24,994		9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
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				38
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				41
2,566,506	-474,848	79,903,863		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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)	27,662,897	34,191,533	Generation
2	Fuel Stock Expenses Undistributed (Account 152)	40,377		
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	17,347,911	18,665,272	Distribution
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	23,699,413	23,724,986	Generation
8	Transmission Plant (Estimated)	135,225	225,427	Transmission
9	Distribution Plant (Estimated)	5,661,207	7,083,996	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	2,388,836	2,252,410	Power Operations
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	49,232,592	51,952,091	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	3,627,267	3,657,581	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	80,563,133	89,801,205	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2020 No. (d)	2020 Amt. (e)
1	Balance-Beginning of Year	62,781.00		10,031.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	2,692.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	60,089.00		10,031.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	1,201.44		193.15	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	193.15			
40	Balance-End of Year	1,008.29		193.15	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		13		
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2021		2022		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
10,028.00		10,032.00		102,690.00		195,562.00		1
								2
								3
				2,640.00		2,640.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						2,692.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
10,028.00		10,032.00		105,330.00		195,510.00		29
								30
								31
								32
								33
								34
								35
193.15		193.15		3,429.25		5,210.14		36
								37
								38
				193.15		386.30		39
193.15		193.15		3,236.10		4,823.84		40
								41
								42
								43
					2		15	44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		2020	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

RE 54 PGE 2019 FERC Form 1
Page 108
June 30, 2020

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2021		2022		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
								3
								4
								5
								6
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								43
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								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22	Abandoned Trojan Nuclear Plant					
23	Decommissioning Costs;	417,724,335	69,834,906		1,900,000	93,989,842
24	PGE has the authority to continue					
25	the recovery of the expense in					
26	rates until decommissioning is					
27	complete, as authorized by OPUC					
28	(Order No. 07-015, dtd 1/12/2007)					
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	417,724,335	69,834,906		1,900,000	93,989,842

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

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

In addition to normal expenses, during 2019, the Nuclear Regulatory Commission issued PGE a renewed license to operate the Independent Spent Fuel Storage Installation at the former Trojan location through the first quarter of 2059. PGE updated its Asset Retirement Obligation ARO (Acct. 230) and increased the Trojan ARO by $68,501,414, with a corresponding increase in Unrecovered plant (Acct. 182.2), to reflect the estimated costs through this new date.

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	Other	8,813	561.6		
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Schedule Page: 231 Line No.: 2 Column: a

Represents study costs charged but not assigned to specific studies.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Tax Benefits Related to Book/Tax Basis Differences	36,170,878		282	3,883,560	32,287,318
2	Previously Flowed to Customers	13,719,986		283	1,473,073	12,246,913
3	(Amort. period is based on the lives of the					
4	properties, approximately 25 years.)					
5						
6	Price Risk Management	131,438,076	95,030,232	547/555	131,438,076	95,030,232
7						
8	Deferred Broker Settlement	2,731,600	3,657,859	555	6,389,459	
9						
10	Intervenor Funding (original deferral per OPUC	633,888	320,792			954,680
11	Order No. 03-388 dtd 7/2/2003)					
12						
13	Coyote Springs Major Maintenance Accrual LTSA	922,252	5,071,081	553	3,446,928	2,546,405
14	(per OPUC GRC 95-1216, dtd 11/20/1995)					
15						
16	Port Westward Major Maintenance Accrual	(34,515)	34,515			
17	(per OPUC GRC Order No.13-459, dtd 12/9/2013)					
18						
19	Residual Deferred Account	291,926	20,123			312,049
20	(per OPUC Order No. 10-279 dtd 7/23/2010)					
21						
22	Glass Insulator Deferral	5,611,560		571	106,332	5,505,228
23	(per OPUC Order No. 10-478 dtd 12/17/2010;					
24	UE 215 First Revenue Requirement Stipulation)					
25	Amortization period: 56 years					
26						
27	Pension Funding	226,430,189		219	13,591,212	212,838,977
28	Postretirement Funding	(4,653,839)	4,766,587	219	80,851	31,897
29	(Per SFAS No. 158 adopted 12/31/2006;					
30	OPUC Order No. 07-051 dtd 2/12/2007)					
31						
32	Boardman Decommissioning Balancing	86,577	40,762	421/456	174,077	-46,738
33	(Per Advice No. 11-07 dtd 05/27/2011)					
34						
35	Automated Demand Response Cost Recovery Mechanism	1,936,215	3,146,584	407.3	4,948,512	134,287
36	(Per OPUC Advice No. 17-29, dtd 11/13/17)					
37	(Amortization period 1/1/2018-12/31/2018)					
38						
39	Demand Response Recovery Pilots					
40	Res Thermostat Direct Install	213,434	1,959,770			2,173,204
41	Res Pricing Program	95,602	2,201,951			2,297,553
42	(Per OPUC Order No. 18-381, dtd 10/11/2018)					
43						
44	TOTAL	467,226,599	172,667,205		217,035,588	422,858,216

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	CET Deferral (2014-2018 vintages)	11,566,808	846,819	903	3,289,750	9,123,877
2	(amortization per OPUC Order No. 17-511,					
3	dtd 12/18/17)					
4	(Amortization period 01/01/2018-12/31/2022)					
5						
6	Schedule 110 Energy Efficiency	15	1,282,012	407.3/421	1,277,477	4,550
7	(per OPUC Advice No. 10-01)					
8						
9	Deferred Cost - Pricing Program	1,001,209	533,926	407.3/421	1,613,312	-78,177
10	(Per OPUC Order No. 19-313 dtd 9/26/19, UM 1708)					
11	(Amortization period 1/1/2020-12/31/2021)					
12						
13	Deferred Cost - DLC Thermostat	1,182,115	1,826,723	407.3	678,479	2,330,359
14	(Per OPUC Order No.19-313 dtd 9/26/19, UM 1708)					
15	(Amortization period 1/1/2020-12/31/2021)					
16						
17	Gresham Privilege Tax Collection Deferral	6,216,998	240,978	421	1,658,611	4,799,365
18	(Advice No. 17-05, Schedule 134, dtd 02/24/17)					
19	(Amortization period 1/1/2018-12/31/2022)					
20						
21	Portland Harbor Environmental	7,953,473	11,114,451	Various	4,436,581	14,631,343
22	Remediation Deferral					
23	(Per OPUC Order No. 17-071,					
24	Docket No. UM1789, dtd 03/02/17)					
25						
26	Residential Sch123 SNA Deferral-2016	(81,523)	135,082	456/421	53,559	
27	(Per OPUC Order No. 16-039, dtd 1/26/2016)					
28	(Amortization period 1/1/2018-12/31/2018)					
29						
30	Residential Sch123 SNA Deferral-2017	14,677,425	862,749	456	15,617,303	-77,129
31	(reauthorized Advice No. 16-23, dtd 11/23/2016)					
32						
33	Residential Sch123 SNA Deferral-2018	2,839,114	1,645,074			4,484,188
34	(reauthorized Advice No. 16-23, dtd 11/23/2016)					
35						
36	Lost Revenue Recovery-2017	1,108,558	21,995	456	1,115,161	15,392
37	(Per OPUC Order No. 16-359 dtd 9/26/2016,					
38	amortization period 1/1/2019-12/31/2019,					
39	per Advice No. 17-24)					
40						
41	Residential Water Heater	328,186	1,903,779	407.3	1,961,965	270,000
42	(Per OPUC Order 19-282, UM 1827 dtd 8/29/19)					
43	(Amortization period 1/1/2020-12/31/2020)					
44	TOTAL	467,226,599	172,667,205		217,035,588	422,858,216

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1						
2	Interest Rate Swap	4,166,551	4,687,976	427/428/24	4,270,728	4,583,799
3	Interest Rate Hedges for Long Term Debt					
4						
5	Transportation Electrification Prgm	220,275	288,546	107	199,218	309,603
6	(Per UM 1811, Order No. 18-124, dtd 4/12/2018)					
7						
8	Multifamily Water Heater	70,643	2,821,610	407.3/421	1,871,710	1,020,543
9	(Per Advice Filing No. 17-06, UM-1827,					
10	Order No. 17-224, dtd 6/27/2017)					
11						
12	Multnomah County Business Income Tax Balancing	382,923		242	165,128	217,795
13	(per Advice 11-27 dtd 10/27/2012)					
14						
15	Community Solar		861,422	407.3	520,004	341,418
16	(Per UM-1977, OPUC Order No. 18-477,					
17	dtd 12/19/2018)					
18						
19	Photovoltaic Volumetric Incentive Pilot		9,134,104	254/407.3	9,134,104	
20	(Per OPUC Order No. 10-198 dtd 5/28/2010)					
21	(Reauthorized OPUC Order No. 15-185 dtd 6/09/2015)					
22						
23	Residential Sch123 SNA Deferral-2019		14,328,637	229/449.1/	2,366,972	11,961,665
24	(Reauthorized Advice No. 16-23, dtd 11/23/2016)			456		
25						
26	Non-residential Sch 123 SNA Deferral 2019		2,844,033	456	236,413	2,607,620
27	(reauthorized Advice No. 16-23, dtd 11/23/2016)					
28						
29	Research & Development Tax Credits		475,000	254/923	475,000	
30	(Per UM-1991, OPUC Order No. 18-464					
31	dtd 12/14/2018)					
32						
33	PHP PPA expiration 2019 AUT deferral		555,783	555	555,783	
34						
35	Oregon Residential Clean Fuel Credit		6,250	253	6,250	
36	(Per UM-1826, OPUC Order No. 17-512					
37	dtd 12/18/2017)					
38						
39						
40						
41						
42						
43						
44	TOTAL	467,226,599	172,667,205		217,035,588	422,858,216

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Schedule Page: 232.1 Line No.: 21 Column: d

186/254/421

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1						
2	Misc. Undistributed Charges	373,720	487,096	Various	506,595	354,221
3						
4	Net Co-owner / Trust Contributi	264,650	118,552,207	Various	118,500,754	316,103
5						
6	Deferred Rent - WTC Tenant	390,752	15,992	146	406,744	
7	amort. through 2025					
8						
9	Deferred Revolving Credit	878,531	680,336	431	282,642	1,276,225
10	Agreement Fees					
11	amort. through 2020					
12						
13	Dispatchable Generation	11,220,453	2,935,397	903	3,353,101	10,802,749
14	various amort. periods from					
15	2009 and extending through 2028					
16						
17	LID Receivable from WTC Tenants	65,882		224	65,882	
18	amort. over 20 yrs through 2029					
19						
20	Utility Property Sales-	58,985	1,906,550	254	1,921,586	43,949
21	Selling Expenses					
22						
23						
24						
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44						
45						
46						
47	Misc. Work in Progress	600,354				687,223
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	13,853,327				13,480,470

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Schedule Page: 233 Line No.: 6 Column: d

Prior to November 2018:
PGE leased the World Trade Center complex in Portland and subleased a portion to external tenants. Two tenants had leasehold improvement loans.
Starting November 2018:
121 Southwest Salmon Street Corp, a PGE subsidiary, purchased the World Trade Center complex in Portland. It assumed the subleases of the PGE tenants and leases space to PGE. It also assumed the associated assets/liabilities, including the tenant leasehold improvement loans. The accounting transaction to transfer the leashold improvement loans was made in 2019.

Schedule Page: 233 Line No.: 17 Column: d

The underlying loan associated with this receivable was paid off as part of the acquisition of the World Trade Center complex in 2018 by 121 Southwest Salmon Street Corp, a PGE subsidiary.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Property Related	299,299,706	311,034,575
3	Regulatory Liabilities	26,413,341	22,112,547
4	Employee Benefits	134,186,632	119,856,422
5	Price Risk Management	41,765,483	36,064,583
6	Tax Credits & NOL's	51,996,251	64,215,361
7	Other	21,853,351	5,704,912
8	TOTAL Electric (Enter Total of lines 2 thru 7)	575,514,764	558,988,400
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	4,704,445	4,340,861
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	580,219,209	563,329,261

Notes

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

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

Line 7 - Other

	Ending Bal 12/31/2018	Ending Bal 12/31/2019
Bad Debt Expense	$4,065,620	$1,231,143
Deferred Revenue	2,538,575	2,062,276
Nuclear Decommissioning Trust	6,762,002	-8,981,674
Renewable Energy Development	4,160,089	3,761,140
Miscellaneous	4,327,065	7,632,027
Total Line 7 - Other	$21,853,351	$5,704,912

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

Line 17 - Other Non-Utility

	Ending Bal 12/31/2018	Ending Bal 12/31/2019
Property Related	$4,567,734	$4,265,935
Employee Benefits	136,711	74,926
Total Line 17 - Other Non-Utility	$4,704,445	$4,340,861

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201:			
2	Common Stock	160,000,000		
3				
4	Total Common Stock	160,000,000		
5				
6	Account 2014:			
7	No par Value Cumulative Preferred	30,000,000		
8				
9	Total Preferred Stock	30,000,000		
10				
11				
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CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT AS REACQUIRED STOCK (Account 217)		HELD BY RESPONDENT IN SINKING AND OTHER FUNDS		Line No.
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
89,387,124	1,224,651,067					2
						3
89,387,124	1,224,651,067					4
						5
						6
						7
						8
						9
						10
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						42

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 208	
2	Parent equity contributions from employee stock purchase and	4,804,482
3	compensation and associated income tax benefits	
4	SUBTOTAL ACCOUNT 208	4,804,482
5		
6	Account 209	
7	Reduction in par or stated vaue of Common Stock	1,556,498
8	SUBTOTAL ACCOUNT 209	1,556,498
9		
10	Account 210	
11	Capital Restructuring Costs	49,120
12	SUBTOTAL ACCOUNT 210	49,120
13		
14	Account 211	
15	Miscellaneous paid in capital	640,957
16	Amortization of capital stock expense	-646,425
17	Tax benefits related to stock compensation plans	3,574,988
18	Reacquired common stock	-68,327
19	Former parent assumption of PGE tax liabilities of Non-Qualified Pn	610,028
20	Oregon tax credit related to PGE's separation from parent	8,317,516
21	SUBTOTAL ACCOUNT 211	12,428,737
22		
23		
24		
25		
26		
27		
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29		
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32		
33		
34		
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39		
40	TOTAL	18,838,837

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

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

Represents the assumption of PGE's tax liability by the Company's former parent company on taxable income related to the transfer of non-qualified plan liabilities to PGE from Portland General Holdings, recorded in 2005.

Schedule Page: 253 Line No.: 20 Column: b

PGE generated approximately $13 million of Oregon tax credits that, due to taxable income limitations, were not utilized by the Company's former parent company prior to the separation of the two companies on April 3, 2006. Prior to 2006, pursuant to a tax sharing agreement, PGE utilized these tax credits to reduce its tax payment obligations to its former parent; however, the former parent was unable to utilize these credits on its tax returns. PGE then utilized a portion of the tax credits to offset quarterly income tax payments due to the State of Oregon during periods subsequent to the separation, with no effect on income. In 2008 and 2009, the realization of such tax credits by PGE was reflected as an adjustment to equity, net of related federal tax effect.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock	23,113,532
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	23,113,532

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221 - Bonds:		
2	First Mortgage Bonds -		
3	9.31% Medium-Term Note Series Due 8/11/2021	20,000,000	176,577
4	6.75% Series VI Due 8/1/2023	50,000,000	519,234
5			437,500 D
6	6.875% Series VI Due 8/1/2033	50,000,000	519,257
7			437,500 D
8	6.26% Series Due 5/1/2031	100,000,000	723,856
9	6.31% Series Due 5/1/2036	175,000,000	1,270,565
10	5.80% Series Due 6/1/2039	170,000,000	1,460,968
11	5.81% Series Due 10/1/2037	130,000,000	1,109,574
12			517,518 D
13	6.10% Series Due 4/15/2019 - Order No. 09-089 03/16/2009	300,000,000	2,386,224
14			222,000 D
15	5.43% Series Due 5/3/2040 - Order No. 09-245 06/22/2009	150,000,000	1,034,284
16	4.47% Series Due 6/15/2044 - Order No. 13-098 03/26/2013	150,000,000	1,113,047
17	4.47% Series Due 8/14/2043 - Order No. 13-098 03/26/2013	75,000,000	558,740
18	4.84% Series Due 12/15/2048 - Order No. 13-098 03/26/2013	50,000,000	311,154
19	4.74% Series Due 11/15/2042 - Order No. 13-098 03/26/2013	105,000,000	652,029
20	4.39% Series Due 8/15/2045 - Order No. 14-145 04/29/2014	100,000,000	645,383
21	4.44% Series Due 10/15/2046 - Order No. 14-145 04/29/2014	100,000,000	625,030
22	3.51% Series Due 11/15/2024 - Order No. 14-145 04/29/2014	80,000,000	501,502
23	3.55% Series Due 1/15/2030 - Order No. 14-399 11/12/2014	75,000,000	325,296
24	3.50% Series Due 5/15/2035 - Order No. 14-399 11/12/2014	70,000,000	305,128
25	2.51% Series Due 1/6/2021 - Order No. 14-399 11/12/2014	140,000,000	592,932
26	3.98% Series Due 11/21/2047 - Order No. 16-152 04/21/2016	150,000,000	-44,757
27	3.98% Series Due 8/3/2048 - Order No. 16-152 04/21/2016	75,000,000	-99,510
28	4.47% SERIES DUE 12-11-2048 Order No. 16-152 04/21/2016	75,000,000	336,938
29	4.30% Series Due 4/11/2049 Order No. 18-453 12/04/2018	200,000,000	860,461
30	3.34% Series due 10/15/2049 Order No. 18-453 12/04/2018	110,000,000	477,767
31	3.34% Series due 1/15/2050 Order No. 18-453 12/04/2018	160,000,000	694,934
32			
33	TOTAL	2,957,883,849	21,286,298

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			
2	Pollution Control Bonds (Guaranteed by Company) -		
3	City of Forsyth, MT Series 1998A 5% Due 5/1/2033	97,800,000	2,615,167
4	SUBTOTAL ACCOUNT 221	2,957,800,000	21,286,298
5			
6	ACCOUNT 224 - OTHER LONG TERM DEBT		
7	City of Portland Improvement District Loan	83,849	
8	SUBTOTAL ACCOUNT 224	83,849	
9			
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32			
33	TOTAL	2,957,883,849	21,286,298

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
08/12/1991	08/11/2021	08/12/1991	08/11/2021	20,000,000	1,862,000	3
08/01/2003	08/01/2023	08/01/2003	08/01/2023		2,756,250	4
						5
08/01/2003	08/01/2033	08/01/2003	08/01/2033	50,000,000	3,437,500	6
						7
05/26/2006	05/01/2031	05/26/2006	05/01/2031	100,000,000	6,260,000	8
05/26/2006	05/01/2036	05/26/2006	05/01/2036	175,000,000	11,042,500	9
05/16/2007	06/01/2039	05/16/2007	06/01/2039	170,000,000	9,860,000	10
09/19/2007	10/01/2037	09/19/2007	10/01/2037	130,000,000	7,553,000	11
						12
04/16/2009	04/15/2019	04/16/2009	04/15/2019		5,337,500	13
						14
11/30/2009	05/03/2040	11/30/2009	05/03/2040	150,000,000	8,145,000	15
6/27/2013	06/15/2044	6/27/2013	06/15/2044	150,000,000	6,705,000	16
8/29/2013	8/14/2043	8/29/2013	8/14/2043	75,000,000	3,352,500	17
12/16/2013	12/15/2048	12/16/2013	12/15/2048	50,000,000	2,420,000	18
11/15/2013	11/15/2042	11/15/2013	11/15/2042	105,000,000	4,977,000	19
8/15/2014	8/15/2045	8/15/2014	8/15/2045	100,000,000	4,390,000	20
10/15/2014	10/15/2046	10/15/2014	10/15/2046	100,000,000	4,440,000	21
11/17/2014	11/15/2024	11/17/2014	11/15/2024	80,000,000	2,808,000	22
1/15/2015	1/15/2030	1/15/2015	1/15/2030	75,000,000	2,662,500	23
5/15/2015	5/15/2035	5/15/2015	5/15/2035	70,000,000	2,450,000	24
1/6/2016	1/6/2021	1/6/2016	1/6/2021	140,000,000	3,514,000	25
11/21/2017	11/21/2047	11/21/2017	11/21/2047	150,000,000	5,970,000	26
8/3/2017	8/3/2048	8/3/2017	8/3/2048	75,000,000	2,985,000	27
12/11/2018	12/11/2048	12/11/2018	12/11/2048	75,000,000	3,352,500	28
4/19/2019	4/11/2049	12/11/2019	12/11/2049	200,000,000	6,211,871	29
10/15/2019	10/15/2049	10/15/2019	10/15/2049	110,000,000	673,567	30
11/15/2019	1/15/2050	11/15/2019	1/15/2050	160,000,000	682,844	31
						32
				2,607,800,000	118,738,532	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
05/28/1998	05/01/2033	05/28/1998	05/01/2033	97,800,000	4,890,000	3
				2,607,800,000	118,738,532	4
						5
						6
11/16/2009	11/16/2029					7
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				2,607,800,000	118,738,532	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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)	213,848,540
2		
3		
4	Taxable Income Not Reported on Books	
5	Depreciation, Depletion & Amortization	34,763,920
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Price Risk Management and Mark-to-Market	-42,043,425
11	Regulatory Credits	-14,374,105
12	Other (See Footnote)	-80,802,451
13		
14	Income Recorded on Books Not Included in Return	
15	Depreciation, Depletion & Amortization	-15,599,662
16	Regulatory Debits	43,891,364
17	Other (See Footnote)	-5,384,129
18		
19	Deductions on Return Not Charged Against Book Income	
20	Depreciation, Depletion & Amortization	3,893,166
21	State & Local Tax Deduction	-8,717,081
22	Other (See Footnote)	-8,812,265
23		
24		
25		
26		
27	Federal Tax Net Income	120,663,872
28	Show Computation of Tax:	
29	Normal Federal Current Provision Benefit @ 21%	25,339,413
30	Federal Credit Tax	-19,271,508
31	RTA Federal Tax Adjustment	1,990,746
32	Other Items Affecting Tax	-348,759
33	Total Federal Income Tax - PGE	7,709,892
34		
35		
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44		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

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

Line 12 - Deductions Recorded on Books Not Deducted for Return

Qualified NDT	3,163,728
Meals & Entertainment	1,500,000
Political Activity	1,199,463
Bad Debts	(10,307,188)
Fines and Penalties	132,974
Employee Benefits	(46,190,424)
Federal Tax Expense	6,381,537
Orion Contingent Royalty Payments	(416,920)
Tax Finance Lease	(46,153,665)
Unamortized loss on reacquired debt	(5,809,984)
State Tax Expense	19,728,982
Deferred Revenue	(1,464,448)
Miscellaneous	(2,566,506)
Total Other	**(80,802,451)**

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

Line 17 - Income Recorded on Books Not Included in Return

Key Man Insurance Proceeds	(2,625,511)
OCI	(2,396,295)
Miscellaneous	(362,323)
Total Other	**(5,384,129)**

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

Line 22 - Deductions on Return Not Charged Against Book Income

Dividend Received Deduction	(26,638)
Prepaid	(5,208,721)
Environmental Remediation	(1,875,000)
Renewable Energy Initiatives	214,289
Property Tax	(1,809,847)
Miscellaneous	(106,348)
Total Other	(8,812,265)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal:					
2	FERC Resale/Coord	220,745		842,581	850,661	
3	Income Tax	1,073,085		7,645,470	12,338,360	-16,013
4	Foreign Insurance Excise Tax					
5	FICA (Employer Share)	3,090,248		27,029,689	26,530,010	
6	Unemployment	64,100		153,504	145,179	
7	Power License	272,328	-34,206	2,179,085	2,169,369	
8	Superfund Tax					
9	SUBTOTAL Federal	4,720,506	-34,206	37,850,329	42,033,579	-16,013
10	State of Montana:					
11	Income Tax	113,132		198,055		
12	Electric Energy Producers	196,302		759,900	745,032	
13	Property Taxes	3,815,526		7,802,109	7,722,714	
14	SUBTOTAL Montana	4,124,960		8,760,064	8,467,746	
15	State of Oregon:					
16	Corp Excise Tax	2,194,507		9,745,446	19,620,192	-6,272
17	Property Taxes		30,380,623	62,926,716	65,094,389	861,874
18	City Taxes & Licenses	3,470,914	23,454	44,951,161	44,893,634	
19	Public Utility Comm Fees			6,093,860	6,015,330	
20	Department of Energy		1,208,291	2,407,834	2,162,449	
21	Department of Enviro Quality	543,699		367,070	421,064	
22	Unemployment	-39,415		2,089,101	1,829,675	
23	Water Power Fee		602,265	603,680	632,183	
24	Transportation Tax	430,172		1,916,045	1,821,537	
25	Workers Comp Assessment	-55,356		103,101	204,459	
26	County & City Income Tax	-248,221		514,312	955,000	-3,126
27	SUBTOTAL Oregon	6,296,300	32,214,633	131,718,326	143,649,912	852,476
28	State of Washington:					
29	Property Taxes	1,940,494		2,579,038	2,151,428	15,153
30	Sales Tax					
31	SUBTOTAL WASHINGTON	1,940,494		2,579,038	2,151,428	15,153
32	State of Utah					
33	Income Tax					
34	SUBTOTAL Utah					
35	State of California:					
36	Corporate Franchise Tax	-21,152		1,086,277		
37	SUBTOTAL California	-21,152		1,086,277		
38	Canada					
39	Goods & Services Tax					
40	SUBTOTAL Canada					
41	TOTAL	17,061,108	32,180,427	181,994,034	196,302,665	851,616

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
212,665					842,581	2
	3,635,818	8,855,226			-1,274,178	3
						4
3,589,927		14,019,078			13,010,611	5
72,425		83,992			69,512	6
282,135	-34,115				1,040,740	7
					1,138,345	8
4,157,152	3,601,703	22,958,296			14,827,611	9
						10
	-311,187	210,386			-12,331	11
211,170		443,904			315,996	12
3,894,921		5,584,762			2,217,353	13
4,106,091	-311,187	6,239,052			2,521,018	14
						15
243,008	7,929,519	10,205,996			-396,128	16
	31,686,422	60,022,046			2,904,664	17
3,504,987		45,016,039			-64,878	18
	-78,530				6,093,860	19
	962,906	2,407,834				20
489,705					367,070	21
220,011		1,143,084			946,017	22
	630,768				603,680	23
524,680		1,048,394			867,651	24
-156,714		56,413			46,688	25
	692,035	546,343			-32,031	26
4,825,677	41,823,120	120,446,149			11,336,593	27
						28
2,383,257		2,579,038				29
						30
2,383,257		2,579,038				31
						32
						33
						34
						35
	-1,065,125	1,093,820			-7,543	36
	-1,065,125	1,093,820			-7,543	37
						38
						39
						40
15,472,177	44,048,511	153,316,355			28,677,679	41

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

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

Line 17 - Adjustments
$861,874 Property Tax Charged to Affiliates

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

Line 29 - Adjustments
$15,153 Property Tax Billed to Partners

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6							
7							
8	TOTAL						
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
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11							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
			6
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			8
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			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits	Balance at Beginning of Year	DEBITS		Credits	Balance at End of Year
			Contra Account	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Tenant security deposits	241,671	234	241,671		
2						
3	Deferred Liability for Transferred	575,556	421	20,430		555,126
4	Non-Qualified Plan Benefits					
5						
6	Reserve for Environmental	4,000,000				4,000,000
7	Remediation Costs					
8						
9						
10	Deferral of Precedent Transmission	3,204,986	232	1,749,544		1,455,442
11	Service Agreement with DET, EDF					
12						
13	Northwest Natural Mist Storage	131,103,475	107	131,103,475		
14	Capital Lease Accrual					
15						
16	Clean Fuels Program		232,926	464,852	9,306,694	8,841,842
17	OPUC 17-250 and 17-512					
18						
19	Price Risk Management		232	295,008		-295,008
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	139,125,688		133,874,980	9,306,694	14,557,402

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Schedule Page: 269 Line No.: 1 Column: c

Prior to November 2018:
PGE leased the World Trade Center complex in Portland and subleased a portion to external tenants. Tenant lease deposits were on PGE's balance sheet.
Starting November 2018:
121 Southwest Salmon Street Corp, a PGE subsidiary, purchased the World Trade Center complex in Portland. It assumed the subleases of the PGE tenants and leases space to PGE. The tenant deposits were transferred to the subsidiary, however the accounting transaction was not made until April 2019.

Schedule Page: 269 Line No.: 16 Column: c

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

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

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

NOTES

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

3. Use footnotes as required.

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

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	802,222,298	69,771,524	67,854,193
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	802,222,298	69,771,524	67,854,193
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	802,222,298	69,771,524	67,854,193
10	Classification of TOTAL			
11	Federal Income Tax	646,548,348	46,710,377	48,332,651
12	State Income Tax	145,780,277	21,614,226	18,301,252
13	Local Income Tax	9,893,673	1,446,921	1,220,290

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
		182.3	14,195,071	254	10,311,512	800,256,070	2
							3
							4
			14,195,071		10,311,512	800,256,070	5
							6
							7
							8
			14,195,071		10,311,512	800,256,070	9
							10
			10,151,774		7,720,595	642,494,895	11
			3,798,868		2,432,995	147,727,378	12
			244,429		157,922	10,033,797	13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Property Related	13,719,964		
4	Price Risk Management	5,620,015	10,397,922	5,682,683
5	Regulatory Assets	115,938,840	35,318,692	47,675,029
6	Regulatory Liabilities			
7	Other	12,158,457	10,981,303	8,856,835
8				
9	TOTAL Electric (Total of lines 3 thru 8)	147,437,276	56,697,917	62,214,547
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	-85,296		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	147,351,980	56,697,917	62,214,547
20	Classification of TOTAL			
21	Federal Income Tax	103,254,044	42,161,064	46,027,150
22	State Income Tax	41,341,118	13,628,029	15,175,384
23	Local Income Tax	2,756,818	908,824	1,012,013

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
		254	5,211,315	182.3	3,738,199	12,246,848	3
						10,335,254	4
						103,582,503	5
							6
						14,282,925	7
							8
			5,211,315		3,738,199	140,447,530	9
							10
							11
							12
							13
							14
							15
							16
							17
1,592,947	625,051	254	1,140	182.3	1,182	882,642	18
1,592,947	625,051		5,212,455		3,739,381	141,330,172	19
							20
1,223,232	544,851		3,794,314		2,761,976	99,034,001	21
346,569	75,151		1,330,171		916,989	39,651,999	22
23,146	5,049		87,970		60,416	2,644,172	23

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

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

	Beginning Balance	Ending Balance
ASC 715 Pension & Post Retirement	60,988,492	58,539,486
ASC 980 Mark-to-Market	27,252,773	26,133,312
Miscellaneous	7,620,698	14,075,100
Price Risk Mgmt Deferral	10,038,496	-
Decoupling	4,711,148	(231,530)
CET Deferral	3,156,653	2,331,247
Feed in Tariff (FIT)	-17,372	(14,225)
Portland Harbor (PHERA)	2,187,952	2,749,113
Subtotal Regulatory Assets	115,938,840	103,582,503

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

	Beginning Balance	Ending Balance
Prepaid Property Tax	7,758,863	8,285,585
Unamortized Loss on Reacquired Debt	4,399,594	5,997,340
Total	12,158,457	14,282,925

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

	Balance at Beg. Of Year	Balance at End Of Year
Trust-Owned Life Insurance Gain/Loss	155,692	463,330
Other	(240,988)	419,312
Total Other	(85,296)	882,642

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Excess Deferred Income Taxes	317,301,456	190/411.1	13,086,271		304,215,185
2						
3	Gain on Asset Sales	754,523	407.4	145,451	1,257,429	1,866,501
4	(Per OPUC Order No. 01-777 dtd 8/31/2001)					
5						
6	Boardman Severance	8,789,939	456	2,038,843	2,266,836	9,017,932
7	Advice No.14-18, dtd 11/3/2014					
8						
9	Asset Retirement Obligations:	53,282,174	407.3	9,915,474	10,314,412	53,681,112
10	Balancing Account					
11						
12	Carty Major Maintenance Deferral	844,279	456	3,498,973	3,241,749	587,055
13	(Per OPUC Order 15-356 UE-294					
14	dtd 11/3/15)					
15						
16	Colstrip Major Maintenance Deferral	2,580,408	456	71,368	3,336,136	5,845,176
17	(Per OPUC UE-319, Order No. 17-511,					
18	dtd 12/18/17)					
19						
20	Coyote Springs Major Maintenance Deferral	3,146,462	456	4,759,152	1,612,690	
21	(Per OPUC Order No. 01-777 dtd 8/31/2001;					
22	reauthorization OPUC Order No. 10-478					
23	dtd 12/17/2010)					
24						
25	Port Westward 2 Major Maintenance Deferral	1,803,130	456	202,307	384,289	1,985,112
26	(Per OPUC 2015 GRC Docket UE-283,					
27	OPUC Order No.14-422, dtd 12/4/2014)					
28						
29	ISFSI Pollution Control Tax Credit Deferral	110,506	407.4	110,965	459	
30	(Per OPUC Order No. 05-136, dtd 3/15/2005)					
31						
32	Zero Interest Program Loan Repayments	3,035,868			327,245	3,363,113
33	(Per Advice No. 05-19 dtd 12/20/2005)					
34						
35	Schedule 110 Energy Efficiency - Balancing Accout	348,778	182.3	401,440	103,051	50,389
36	(Per Advice No. 07-25 dtd 5/20/2008)					
37						
38	Sunway 3 Investment Deferral	522,910	407.4	45,480		477,430
39	(Per UM 1480 dtd 4/01/2010;					
40	(Amortization over 20 years commencing 2010)					
41	TOTAL	400,701,445		46,829,625	54,684,893	408,556,713

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1						
2	Trojan Decommissioning Deferral	398,998	407	2,953,972	5,848,219	3,293,245
3	(Per OPUC UE-319, Order No.17-511,					
4	dtd 12/18/2017)					
5	(Amortization period 1/1/2019-12/31/2019)					
6						
7	PRC Acquisition	3,542,293			58,746	3,601,039
8	(Per OPUC UE-283 Final GRC Order No.14-422,					
9	dtd 12/04/2014, Second Partial					
10	Stipulation dtd 9/2/2014)					
11						
12	North Fork Surface Collector	(20,962)	456	15,823	36,785	
13	(Per OPUC order 15-356 UE294 dtd 11/3/15)					
14						
15	Deferred Broker Settlement	415,800	182.3	415,800	105,850	105,850
16						
17	Direct Access Open Enrollment - 2017	50,760	447	50,858	98	
18	(Per OPUC Order 17-109 UM-1301					
19	dtd 3/21/2017)					
20						
21	Photovoltaic Volumetric Incentive Pilot	1,026,390	182.3	1,026,390	2,900,321	2,900,321
22	(Per OPUC Order 10-198 dtd 5/28/2010					
23	reauthorized OPUC Order 15-185					
24	dtd 6/09/2015)					
25						
26	Portland Harbor Enviornmental Deferral	2	421	2,768		-2,766
27	(Per OPUC Order No. 17-071, UM-1789					
28	dtd 03/02/17)					
29						
30	PHP PPA Expiration 2018 AUT Refund	(537,769)			537,769	
31	(Per OPUC Order 16-494, UE-308					
32	dtd 12/20/16)					
33						
34	Oregon Residential Clean Fuel Credit	3,305,500	253	5,492,263	2,186,763	
35	(Per UM-1826, OPUC Order No. 17-512,					
36	dtd 12/18/2017)					
37						
38	Price Risk Management				1,469,031	1,469,031
39						
40						
41	TOTAL	400,701,445		46,829,625	54,684,893	408,556,713

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Monet NVPC QF Deferral				1,156,116	1,156,116
2	(Per UE-335 NVPC Stipulation,					
3	OPUC Order No. 18-405					
4						
5	Research & Development Tax Credits				4,733,455	4,733,455
6	(Per UM-1991, OPUC Order No. 18-464					
7	dtd 12/14/2018)					
8						
9	Postretirement Plans		219/254	2,596,027	10,981,796	8,385,769
10	(Per SFAS No. 158 adopted 12/31/2006;					
11	OPUC Order No. 07-051 dtd 2/12/2007)					
12						
13	Lease Obligation Balancing Account				751,148	751,148
14						
15	Direct Access Deferral - 2019				1,074,500	1,074,500
16	(Per UM-1301, Order No. 19-045					
17	dated 12/30/2019)					
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	400,701,445		46,829,625	54,684,893	408,556,713

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	917,792,335	890,376,597
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	638,317,031	648,540,186
5	Large (or Ind.) (See Instr. 4)	221,934,941	209,586,172
6	(444) Public Street and Highway Lighting	11,259,467	11,648,005
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,789,303,774	1,760,150,960
11	(447) Sales for Resale	203,335,776	177,074,310
12	TOTAL Sales of Electricity	1,992,639,550	1,937,225,270
13	(Less) (449.1) Provision for Rate Refunds	-24,671,723	40,343,222
14	TOTAL Revenues Net of Prov. for Refunds	2,017,311,273	1,896,882,048
15	Other Operating Revenues		
16	(450) Forfeited Discounts	7,533,569	6,004,495
17	(451) Miscellaneous Service Revenues	1,918,764	1,193,165
18	(453) Sales of Water and Water Power	-25,668	-11,415
19	(454) Rent from Electric Property	11,854,326	9,088,824
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	98,951,224	81,392,177
22	(456.1) Revenues from Transmission of Electricity of Others	10,438,921	10,560,749
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	130,671,136	108,227,995
27	TOTAL Electric Operating Revenues	2,147,982,409	2,005,110,043

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
7,471,069	7,415,759	779,673	772,389	2
				3
6,603,269	6,728,483	109,890	108,888	4
3,180,993	2,987,403	262	270	5
49,360	54,357	194	219	6
				7
				8
				9
17,304,691	17,186,002	890,019	881,766	10
5,267,311	4,690,990	35	37	11
22,572,002	21,876,992	890,054	881,803	12
				13
22,572,002	21,876,992	890,054	881,803	14

Line 12, column (b) includes $ -9,740,915 of unbilled revenues.
Line 12, column (d) includes -71,230 MWH relating to unbilled revenues

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

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

Includes $18,052,199 in revenue related to the delivery of 665,844 megawatt hours to customers of Energy Service Suppliers (ESSs). Oregon's electricity restructuring law provides for a "transition adjustment" for customers that choose to purchase energy at market prices from investor-owned utilities or from an ESS. Such charges or credits reflect the above market or below market costs, respectively for energy resources owned or purchased by the utility and are designed to ensure that such costs or benefits do not unfairly shift to the utility's remaining energy customers. For 2019, the "transition adjustment" credits provided to many commercial and industrial customers were less than the charges for delivering the energy they purchased from ESSs. Since this energy was not sold by PGE, the associated megawatt hours are not reported on Page 301(d).

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

Includes $18,220,620 in revenue related to the delivery of 646,936 megawatt hours to customers of Energy Service Suppliers (ESSs). Oregon's electricity restructuring law provides for a "transition adjustment" for customers that choose to purchase energy at market prices from investor-owned utilities or from an ESS. Such charges or credits reflect the above market or below market costs, respectively for energy resources owned or purchased by the utility and are designed to ensure that such costs or benefits do not unfairly shift to the utility's remaining energy customers. For 2017, the "transition adjustment" credits provided to many commercial and industrial customers were less than the charges for delivering the energy they purchased from ESSs. Since this energy was not sold by PGE, the associated megawatt hours are not reported on Page 301(d).

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

Includes $25,500,018 in revenue related to the delivery of 1,489,711 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2019, the "transition adjustment" credits provided to many commercial and industrial customers were less than the charges for delivering the energy they purchased from ESSs. Since this energy was not sold by PGE, the associated megawatt hours are not reported on Page 301(d).

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

Includes $24,428,602 in revenue related to the delivery of 1,388,558 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2018, the "transition adjustment" credits provided to many commercial and industrial customers were less than the charges for delivering the energy they purchased from ESSs. Since this energy was not sold by PGE, the associated megawatt hours are not reported on Page 301(d).

Schedule Page: 300 Line No.: 17 Column: b

Miscellaneous Service Revenues include charges billed in accordance with PGE Tariff Schedule 300 Charges as Defined by the Rules and Regulations and Miscellaneous Charges and Schedule 320 Meter Information Services. Schedule 300 charges recorded to this account include the following:

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

Schedule Page: 300 Line No.: 17 Column: c

Miscellaneous Service Revenues include charges billed in accordance with PGE Tariff Schedule 300 *Charges as Defined by the Rules and Regulations and Miscellaneous Charges* and Schedule 320 *Meter Information Services.* Schedule 300 charges recorded to this account

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

include the following:

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

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

Other Electric Revenues consist of the following:

	2019
2019 ETO Management	$106,421
Boardman Decommissioning Balancing Account	(132,836)
Boardman Ops	176,527
Boardman Severance	(227,993)
Carty Major Maintenance Deferral	257,225
Colstrip - Major Maint Accrual/Defr	(2,795,622)
CSP Major Maintenance Deferral	3,146,462
Gas Resale	17,302,187
Hydro License Implementation and Compliance	885,524
Lost Revenue Recovery	(1,115,160)
MCI Metro	5,121,090
Other	1,203,676
PW1 - Major Maint Deferral	(469,146)
PW2 - Major Maint Deferral	(181,982)
RPA Balancing	67,208,725
Sch 7 Sales Norm Adj	(2,960,236)
Sch 83 Sales Norm Adj.	2,547,830
Steam Sales	1,874,091
Transmission Resale	6,997,356
Transport Electrification	7,085
Grand Total	$98,951,224

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

Other Electric Revenues consist of the following:

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

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

$81,392,177

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
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43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	(1) Residential					
2	6-Residential Pricing Pilot	26,756	3,265,769	2,583	10,358	0.1221
3	7-Residential Service	7,498,613	919,737,731	777,090	9,650	0.1227
4	15-Outdoor Area Lighting	1,775	659,733			0.3717
5	Residential Unbilled Revenue	-56,075	-5,870,898			0.1047
6	TOTAL Account 440	7,471,069	917,792,335	779,673	9,582	0.1228
7	(3) General Comm. & Ind.					
8	15-Outdoor Area Lighting	13,640	2,760,847			0.2024
9	32-Small Nonresidential	1,584,333	179,370,434	91,915	17,237	0.1132
10	38-Large Nonresidential	32,310	4,230,067	367	88,038	0.1309
11	47-Small Irrigation & Drainage	17,972	3,548,840	2,726	6,593	0.1975
12	49-Large Irrigation & Drainage	57,872	8,098,531	1,463	39,557	0.1399
13	83-Large Nonresidential	2,840,028	257,673,464	11,615	244,514	0.0907
14	85-Large Nonresidential	2,081,620	166,656,500	1,228	1,695,130	0.0801
15	485-Large Nonresidential COS O	23,136	2,127,479	13	1,779,692	0.0920
16	532-Small Nonresidential DAS	-24	-1,088			0.0453
17	583-Large Nonresidential DAS	222	9,468			0.0426
18	585-Large Nonresidential DAS	193	7,569			0.0392
19	(3) ESS General Comm. & Ind.					
20	485-Large Nonresidential COS O		12,265,771	210		
21	489-Large Nonresidential COS O		526,039	1		
22	515-Outdoor Area Lighting DAS		5,711			
23	532-Small Nonresidential DAS		451,708	181		
24	538-Large Nonresidential Opt.		3,680	2		
25	583-Large Nonresidential DAS		1,996,663	122		
26	585-Large Nonresidential DAS		3,963,979	47		
27	General Comm. & Ind. Unbilled	-48,033	-5,378,631			0.1120
28	TOTAL Account 442 - Small	6,603,269	638,317,031	109,890	60,090	0.0967
29	(4) Large Ind. & Trans.					
30	89-Large Nonresidential	77,938	5,658,574	5	15,587,600	0.0726
31	(4) ESS Large Ind. & Trans.					
32	489-Large Nonresidential COS O		1,023,329	2		
33	Large Ind. & Trans. Unbilled R	3,281	184,000			0.0561
34	(5) Large Comm. & Ind.					
35	32-Small Nonresidential		-189			
36	83-Large Nonresidential	-1,563	-134,694			0.0862
37	85-Large Nonresidential	637,545	46,695,327	171	3,728,333	0.0732
38	89-Large Nonresidential	403,623	25,388,983	10	40,362,300	0.0629
39	90-Large Nonresidential	1,989,424	115,100,762	5	397,884,800	0.0579
40	485-Large Nonresidential COS O	14,285	1,225,283	1	14,285,000	0.0858
41	TOTAL Billed	17,375,920	1,799,044,689	890,019	19,523	0.1035
42	Total Unbilled Rev.(See Instr. 6)	-71,230	-9,740,915	0	0	0.1368
43	TOTAL	17,304,690	1,789,303,774	890,019	19,443	0.1034

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	489-Large Nonresidential COS O	25,369	2,080,603	1	25,369,000	0.0820
2	(5) ESS Large Comm. & Ind.					
3	485-Larrge Nonresidential COS		6,382,980	50		
4	489-Large Nonresidential COS O		16,285,963	13		
5	585-Large Nonresidential DAS		550,406	4		
6	Large Comm. & Ind. Unbilled Re	31,090	1,493,614			0.0480
7	TOTAL Account 442 - Large	3,180,992	221,934,941	262	12,141,191	0.0698
8	(6) Street Lighting					
9	91-Street & Hwy Lighting	24,703	6,920,081	177	139,565	0.2801
10	92-Traffic Signals	2,576	212,450	16	161,000	0.0825
11	95-Street & Hwy Lighting (New	23,574	4,295,936	1	23,574,000	0.1822
12	Street Lighting Unbilled Reven	-1,493	-169,000			0.1132
13	TOTAL Account 444	49,360	11,259,467	194	254,433	0.2281
14	Other Sales to Public Authorities					
15	TOTAL Account 445					
16	Sales to Railroads and Railways					
17	TOTAL Account 446					
18	Interdepartmental Sales					
19	TOTAL Account 448					
20						
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41	TOTAL Billed	17,375,920	1,799,044,689	890,019	19,523	0.1035
42	Total Unbilled Rev.(See Instr. 6)	-71,230	-9,740,915	0	0	0.1368
43	TOTAL	17,304,690	1,789,303,774	890,019	19,443	0.1034

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Arizona Public Service	SF	WSPP-1	NA	NA	NA
2	Avangrid Renewables (was Iberdrola)	SF	EEI	NA	NA	NA
3	Avista Corp.	SF	WSPP-1	NA	NA	NA
4	BP Energy Company	SF	PGE-11	NA	NA	NA
5	Black Hills Power	SF	WSPP-1	NA	NA	NA
6	Bonneville Power Administration	SF	WSPP-1	NA	NA	NA
7	British Columbia Hydro & Power Authoiry	SF	WSPP-1	NA	NA	NA
8	Brookfield Energy Marketing LP	SF	WSPP-1	NA	NA	NA
9	CP Energy Marketing	SF	WSPP-1	NA	NA	NA
10	California Independent System Operator	SF	CAISO	NA	NA	NA
11	Calpine Energy Services, L.P.	SF	EEI	NA	NA	NA
12	Calpine Energy Services, L.P.	OS	WSPP-1	NA	NA	NA
13	Chelan County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
14	Citigroup Energy Inc.	SF	WSPP-1	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
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LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	City of Burbank	SF	WSPP-1	NA	NA	NA
2	City of Redding	SF	WSPP-1	NA	NA	NA
3	Clatskanie Peoples Utility District	SF	WSPP-1	NA	NA	NA
4	Clean Power Alliance	OS	WSPP-1	NA	NA	NA
5	Commerce Energy Inc	OS	WSPP-1	NA	NA	NA
6	ConocoPhillips Company	SF	WSPP-1	NA	NA	NA
7	Douglas County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
8	DTE Energy Trading LLC	SF	WSPP-1	NA	NA	NA
9	EAST BAY COMMUNITY ENERGY	SF	WSPP-1	NA	NA	NA
10	EDF Trading North America, LLC	SF	WSPP-1	NA	NA	NA
11	Element Markets	OS	EEI	NA	NA	NA
12	ENMAX Energy Marketing Inc.	SF	WSPP-1	NA	NA	NA
13	Energy Keepers, Inc.	SF	WSPP-1	NA	NA	NA
14	Eugene Water & Electric Board	SF	WSPP-1	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Exelon Generation Company, LLC	SF	EEI	NA	NA	NA
2	Exelon Generation Company, LLC	OS	EEI	NA	NA	NA
3	Gridforce Energy Management	SF	EEI	NA	NA	NA
4	Idaho Power Company	SF	WSPP-1	NA	NA	NA
5	Load Balance Energy	OS	OATT	NA	NA	NA
6	Los Angeles Dept. Water Power	SF	WSPP-1	NA	NA	NA
7	Los Angeles Dept. Water Power	OS	WSPP-1	NA	NA	NA
8	Macquarie Energy LLC	SF	WSPP-1	NA	NA	NA
9	Marin Clean Energy	OS	WSPP-1	NA	NA	NA
10	Modesto Irrigation District	SF	WSPP-1	NA	NA	NA
11	Morgan Stanley Capital Group, Inc.	SF	PGE-11	NA	NA	NA
12	NaturEner Power Watch, LLC	SF	WSPP-1	NA	NA	NA
13	Nevada Power Company	SF	WSPP-1	NA	NA	NA
14	NextEra Energy Power Marketing, LLC	SF	WSPP-1	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	NorthWestern Corporation	SF	WSPP-1	NA	NA	NA
2	PacifiCorp	SF	EEI	NA	NA	NA
3	PacifiCorp	LU	PGE-11	NA	NA	NA
4	Pacific Northwest Generating Company	SF	WSPP-1	NA	NA	NA
5	Powerex Corp.	SF	EEI	NA	NA	NA
6	Pend Orielle County PUD	SF	WSPP-1	NA	NA	NA
7	Public Service Company of Colorado	SF	WSPP-1	NA	NA	NA
8	Public Utility District No. 1 of Okanoy	SF	WSPP-1	NA	NA	NA
9	Public Utility District No. 2 of Granty	SF	WSPP-1	NA	NA	NA
10	Puget Sound Energy	SF	WSPP-1	NA	NA	NA
11	Rainbow Energy Marketing Company	SF	WSPP-1	NA	NA	NA
12	Sacramento Municipal Utility District	SF	WSPP-1	NA	NA	NA
13	Sacramento Municipal Utility District	OS	WSPP-1	NA	NA	NA
14	Seattle City Light	SF	WSPP-1	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Shell Energy North America (US), L.P.	SF	PGE-11	NA	NA	NA
2	Snohomish County, PUD No.1, Washington	SF	WSPP-1	NA	NA	NA
3	Tacoma Power	SF	WSPP-1	NA	NA	NA
4	Tenaska Power Services Co.	SF	WSPP-1	NA	NA	NA
5	The Energy Authority, Inc.	SF	WSPP-1	NA	NA	NA
6	The Energy Authority, Inc.	OS	WSPP-1	NA	NA	NA
7	TransAlta Energy Marketing (U.S.), Inc.	SF	EEI	NA	NA	NA
8	TransCanada Energy Sales Ltd.	SF	WSPP-1	NA	NA	NA
9	Turlock Irrigation District	SF	WSPP-1	NA	NA	NA
10	Vitol Inc.	SF	WSPP-1	NA	NA	NA
11	Westar Energy, Inc.	SF	WSPP-1	NA	NA	NA
12	Western Area Power Authority	SF	WSPP-1	NA	NA	NA
13	Direct Access deferral 2019			NA	NA	NA
14	Direct Access amortization-2019			NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1						
2	Non-RQ Sales:					
3						
4	Portland General Electric Company	SF	OA96137	923	NA	NA
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
212,839		10,400,260		10,400,260	2
56,088		2,799,713		2,799,713	3
126,080		3,843,520		3,843,520	4
70		2,390		2,390	5
218,492		8,486,855		8,486,855	6
9		319		319	7
2,828		94,644		94,644	8
35		2,625		2,625	9
2,121,013		62,968,193		62,968,193	10
111,234		6,621,611		6,621,611	11
			5,562,411	5,562,411	12
1,605		43,965		43,965	13
153,028		5,287,786		5,287,786	14
0	0	0	0	0	
5,267,311	7,312,960	178,086,899	17,935,917	203,335,776	
5,267,311	**7,312,960**	**178,086,899**	**17,935,917**	**203,335,776**	

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
283		19,425		19,425	1
1,917		41,256		41,256	2
2,613		85,646		85,646	3
			6,475,497	6,475,497	4
			1,075,000	1,075,000	5
25,600		721,502		721,502	6
8,123		272,964		272,964	7
42,000		1,353,346		1,353,346	8
		1,798,125		1,798,125	9
49,308		2,703,994		2,703,994	10
			760,000	760,000	11
300		13,925		13,925	12
50,481		2,276,719		2,276,719	13
21,073		649,874		649,874	14
0	0	0	0	0	
5,267,311	7,312,960	178,086,899	17,935,917	203,335,776	
5,267,311	**7,312,960**	**178,086,899**	**17,935,917**	**203,335,776**	

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
39,161		1,837,998		1,837,998	1
			1,681,144	1,681,144	2
556		19,428		19,428	3
10,590		258,361		258,361	4
18,456					5
43,300		1,215,377		1,215,377	6
			527,263	527,263	7
100,075		2,836,757		2,836,757	8
			1,462,500	1,462,500	9
184		9,272		9,272	10
60,425		1,861,645		1,861,645	11
184		4,149		4,149	12
1,010		57,623		57,623	13
800		28,000		28,000	14
0	0	0	0	0	
5,267,311	7,312,960	178,086,899	17,935,917	203,335,776	
5,267,311	**7,312,960**	**178,086,899**	**17,935,917**	**203,335,776**	

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
91,370		2,490,157		2,490,157	1
204,342		6,275,206		6,275,206	2
16,993		92,472		92,472	3
84,000		3,168,000		3,168,000	4
417,793		11,799,257		11,799,257	5
197,876		6,208,614		6,208,614	6
400		10,800		10,800	7
2,475		78,880		78,880	8
1		47		47	9
104,799		4,634,910		4,634,910	10
50		2,600		2,600	11
463		43,643		43,643	12
			910,220	910,220	13
62,008		2,562,714		2,562,714	14
0	0	0	0	0	
5,267,311	7,312,960	178,086,899	17,935,917	203,335,776	
5,267,311	**7,312,960**	**178,086,899**	**17,935,917**	**203,335,776**	

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
163,276		5,462,498		5,462,498	1
22,833		916,986		916,986	2
10,426		323,647		323,647	3
179,134		6,231,088		6,231,088	4
43,732		2,055,114		2,055,114	5
			515,625	515,625	6
168,329		7,010,187		7,010,187	7
9,234		274,640		274,640	8
14		-465,990		-465,990	9
6,400		190,396		190,396	10
1,000		91,500		91,500	11
603		12,266		12,266	12
			-1,074,500	-1,074,500	13
			40,757	40,757	14
0	0	0	0	0	
5,267,311	7,312,960	178,086,899	17,935,917	203,335,776	
5,267,311	**7,312,960**	**178,086,899**	**17,935,917**	**203,335,776**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
					2
					3
	7,312,960			7,312,960	4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
5,267,311	7,312,960	178,086,899	17,935,917	203,335,776	
5,267,311	**7,312,960**	**178,086,899**	**17,935,917**	**203,335,776**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 12 Column: j

Represents sales of renewable energy credits to Calpine.

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

Represents sales of renewable energy credits to Clean Power Alliance

Schedule Page: 310.1 Line No.: 5 Column: j

Represents sales of renewable energy credits to Commerce Energy Inc

Schedule Page: 310.1 Line No.: 11 Column: j

Represents sales of renewable energy credits to Element Market

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

Represents sales of renewable energy credits to Exelon Generation Company

Schedule Page: 310.2 Line No.: 7 Column: j

Represents sales of renewable energy credits to Los Angeles Dept. Water Power

Schedule Page: 310.2 Line No.: 9 Column: j

Represents sales of renewable energy credits to Marin Clean Energy

Schedule Page: 310.3 Line No.: 3 Column: i

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

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

Represents sales of renewable energy credits to Sacramento Municipal Utility District

Schedule Page: 310.4 Line No.: 6 Column: j

Represents sales of renewable energy credits to The Energy Authority, Inc.

Schedule Page: 310.4 Line No.: 13 Column: j

Defer costs associated with the implementation of the annual direct access open enrollment window. See Tariff Schedule 128 filed 01/26/2007.

Schedule Page: 310.4 Line No.: 14 Column: j

Amortization of deferred costs associated with the implementation of the annual direct access open enrollment window. See Tariff Schedule 128 filed 01/26/2007.

Schedule Page: 310.5 Line No.: 4 Column: a

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	2,330,701	2,269,641
5	(501) Fuel	93,517,673	64,189,906
6	(502) Steam Expenses	8,506,261	6,842,388
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	11,103,441	9,158,903
11	(507) Rents	16,802	42,766
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	115,474,878	82,503,604
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	901,629	939,977
16	(511) Maintenance of Structures	1,099,748	993,457
17	(512) Maintenance of Boiler Plant	6,475,812	5,492,382
18	(513) Maintenance of Electric Plant	7,623,269	10,501,988
19	(514) Maintenance of Miscellaneous Steam Plant	936,102	1,360,371
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	17,036,560	19,288,175
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	132,511,438	101,791,779
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	924,616	861,193
45	(536) Water for Power	603,680	578,633
46	(537) Hydraulic Expenses	7,127,838	7,218,727
47	(538) Electric Expenses	1,630,458	1,349,687
48	(539) Miscellaneous Hydraulic Power Generation Expenses	4,037,198	3,596,649
49	(540) Rents	777,790	736,804
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	15,101,580	14,341,693
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	753,270	661,361
54	(542) Maintenance of Structures		15,391
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,263,061	273,082
56	(544) Maintenance of Electric Plant	1,313,156	1,127,324
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,077,945	1,187,981
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	4,407,432	3,265,139
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	19,509,012	17,606,832

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Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	3,719,373	3,212,615
63	(547) Fuel	194,396,475	186,066,953
64	(548) Generation Expenses	8,894,822	9,631,775
65	(549) Miscellaneous Other Power Generation Expenses	19,499,593	14,382,382
66	(550) Rents	1,000,732	1,279,329
67	TOTAL Operation (Enter Total of lines 62 thru 66)	227,510,995	214,573,054
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,860,170	974,431
70	(552) Maintenance of Structures	534,328	548,659
71	(553) Maintenance of Generating and Electric Plant	44,669,783	42,640,875
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,097,144	1,502,039
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	48,161,425	45,666,004
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	275,672,420	260,239,058
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	281,457,582	257,926,636
77	(556) System Control and Load Dispatching	250,780	192,053
78	(557) Other Expenses	22,883,439	22,356,703
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	304,591,801	280,475,392
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	732,284,671	660,113,061
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	7,644,678	6,758,703
84			
85	(561.1) Load Dispatch-Reliability	14,627	14,421
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	961,011	987,062
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,512,133	1,177,969
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies	8,813	9,385
91	(561.7) Generation Interconnection Studies		877
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	206,486	197,059
94	(563) Overhead Lines Expenses	175,946	67,003
95	(564) Underground Lines Expenses		1,199
96	(565) Transmission of Electricity by Others	83,561,883	81,302,712
97	(566) Miscellaneous Transmission Expenses	7,315,275	7,052,153
98	(567) Rents	3,574,527	3,001,643
99	TOTAL Operation (Enter Total of lines 83 thru 98)	104,975,379	100,570,186
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	20,563	34,449
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software	821,808	562,895
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,436,260	1,687,589
108	(571) Maintenance of Overhead Lines	1,299,193	482,177
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	3,483	22
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,581,307	2,767,132
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	108,556,686	103,337,318

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	26,332,943	19,740,951
135	(581) Load Dispatching	2,512,422	1,929,614
136	(582) Station Expenses	961,036	882,668
137	(583) Overhead Line Expenses	2,519,942	1,915,263
138	(584) Underground Line Expenses	3,648,832	3,719,304
139	(585) Street Lighting and Signal System Expenses	380,005	502,923
140	(586) Meter Expenses	3,086,554	3,267,920
141	(587) Customer Installations Expenses	3,885,491	4,789,878
142	(588) Miscellaneous Expenses	9,300,372	8,302,615
143	(589) Rents	1,978,035	2,004,890
144	TOTAL Operation (Enter Total of lines 134 thru 143)	54,605,632	47,056,026
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	44,098	30,667
147	(591) Maintenance of Structures	230,487	138,383
148	(592) Maintenance of Station Equipment	5,711,135	5,505,867
149	(593) Maintenance of Overhead Lines	51,687,071	38,613,423
150	(594) Maintenance of Underground Lines	9,429,811	9,532,302
151	(595) Maintenance of Line Transformers	2,571,576	2,569,234
152	(596) Maintenance of Street Lighting and Signal Systems	1,255,633	644,785
153	(597) Maintenance of Meters	51,996	28,533
154	(598) Maintenance of Miscellaneous Distribution Plant	9,030,454	9,468,977
155	TOTAL Maintenance (Total of lines 146 thru 154)	80,012,261	66,532,171
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	134,617,893	113,588,197
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	398,441	377,022
161	(903) Customer Records and Collection Expenses	55,772,614	50,172,531
162	(904) Uncollectible Accounts	2,155,688	13,160,421
163	(905) Miscellaneous Customer Accounts Expenses	6,944,625	6,568,714
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	65,271,368	70,278,688

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	13,156,211	14,274,536
169	(909) Informational and Instructional Expenses	1,560,301	1,533,064
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	14,716,512	15,807,600
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	81,318,578	72,905,614
182	(921) Office Supplies and Expenses	23,059,355	23,646,995
183	(Less) (922) Administrative Expenses Transferred-Credit	12,888,110	10,755,645
184	(923) Outside Services Employed	8,843,144	-1,226,241
185	(924) Property Insurance	6,659,426	6,250,645
186	(925) Injuries and Damages	5,454,493	4,569,073
187	(926) Employee Pensions and Benefits	62,501,938	64,197,093
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	10,439,272	10,231,618
190	(929) (Less) Duplicate Charges-Cr.	2,769,908	2,456,901
191	(930.1) General Advertising Expenses	1,298,824	543,513
192	(930.2) Miscellaneous General Expenses	18,431,722	14,521,154
193	(931) Rents	4,604,944	5,097,132
194	TOTAL Operation (Enter Total of lines 181 thru 193)	206,953,678	187,524,050
195	Maintenance		
196	(935) Maintenance of General Plant	3,295,290	3,027,931
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	210,248,968	190,551,981
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,265,696,098	1,153,676,845

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	California Independent System Operator	SF	CAISO	NA	NA	NA
2	Calpine Energy Services	SF	PGE-11	NA	NA	NA
3	Case Creek Solar	LU	201	NA	NA	NA
4	Chelan County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
5	Citigroup Energy	SF	WSPP-1	NA	NA	NA
6	Burbank, City of	SF	WSPP-1	NA	NA	NA
7	Roseville, City of	SF	WSPP-1	NA	NA	NA
8	Clatskanie County PUD	SF	WSPP-1	NA	NA	NA
9	CLEAN POWER ALLIANCE OF SOUTHERN	SF	WSPP-1	NA	NA	NA
10	ConocoPhillips	SF	WSPP-1	NA	NA	NA
11	Covanta Marion	LU	QF83-118	NA	NA	NA
12	Douglas County, PUD No. 1, Washington	LF	Wells	NA	NA	NA
13	Douglas County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
14	DTE Energy Trading, Inc.	SF	WSPP-1	NA	NA	NA
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	EAST BAY COMMUNITY ENERGY	SF	WSPP-1			
2	EDF Trading North America, LLC	SF	WSPP-1	NA	NA	NA
3	Enmax	SF	PGE-11	NA	NA	NA
4	Energy Keepers, Inc. - ENKP	SF	WSPP-1	NA	NA	NA
5	ESI Vansycle Partners, LP	LU	WSPP-1	NA	NA	NA
6	Eugene Water & Electric Board	LU	WSPP-1	NA	NA	NA
7	Eugene Water & Electric Board	SF	WSPP-1	NA	NA	NA
8	Evergreen Biomass	LU	201	NA	NA	NA
9	Exelon Generation Co.	SF	WSPP-1	NA	NA	NA
10	Gridforce Energy Management - GRID	SF	WSPP-1	NA	NA	NA
11	Idaho Power Company	SF	WSPP-1	NA	NA	NA
12	JC Biomethane	LU	JCBIO	NA	NA	NA
13	Labish Solar	LU	201	NA	NA	NA
14	Macquarie Cook Power	SF	WSPP-1	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Morgan Stanley Capital Group	SF	PGE-11	NA	NA	NA
2	Nevada Power Company	SF	WSPP-1	NA	NA	NA
3	NorthWestern Corporation	SF	WSPP-1	NA	NA	NA
4	NorthWestern Corporation	OS	WSPP-1	NA	NA	NA
5	Northwestern Energy	SF	WSPP-1	NA	NA	NA
6	Norwest Energy 14	LU	201	NA	NA	NA
7	Obsidian Lakeview	LU	201	NA	NA	NA
8	OE Solar 3, LLC	LU	201	NA	NA	NA
9	OE Solar 4, LLC	LU	201	NA	NA	NA
10	Okanogan County PUD, Washington	SF	WSPP-1	NA	NA	NA
11	O'Neil Solar	LU	201	NA	NA	NA
12	Outback Solar	LU	Outback	NA	NA	NA
13	Pacific Northwest Generating Company	SF	WSPP-1	NA	NA	NA
14	PacifiCorp	SF	PGE-11	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	PaTu Wind	LU	WSPP-1	NA	NA	NA
2	Portland, City of	LU	#2821	NA	NA	NA
3	Powerex	SF	PGE-11	NA	NA	NA
4	Public Service Company of Colorado	SF	WSPP-1	NA	NA	NA
5	Public Utility District No. 1 of Clary	SF	WSPP-1	NA	NA	NA
6	Grant County, PUD No. 2, Washington	LU	Wanapum	NA	NA	NA
7	Grant County, PUD No. 2, Washington	LU	Priest Rapids	NA	NA	NA
8	Grant County, PUD No. 2, Washington	SF	WSPP-1	NA	NA	NA
9	Pend Orielle County PUD	SF	WSPP-1	NA	NA	NA
10	Puget Sound Energy	SF	WSPP-1	NA	NA	NA
11	Rafael Solar	LU	201	NA	NA	NA
12	Sacramento Municipal Utility District	SF	WSPP-1	NA	NA	NA
13	Seattle City Light	SF	WSPP-1	NA	NA	NA
14	Shell Energy	SF	WSPP-1	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Sheep Solar	LU	201	NA	NA	NA
2	Silverton Solar	LU	201	NA	NA	NA
3	Snohomish County, PUD No. 1, Washingn	SF	WSPP-1	NA	NA	NA
4	SP Solar 1, LLC	LU	201	NA	NA	NA
5	SP Solar 5, LLC	LU	201	NA	NA	NA
6	SP Solar 6, LLC	LU	201	NA	NA	NA
7	SP Solar 7, LLC	LU	201	NA	NA	NA
8	SP Solar 8, LLC	LU	201	NA	NA	NA
9	Steel Bridge	LU	201	NA	NA	NA
10	Starvation Solar 1 LLC	LU	201	NA	NA	NA
11	St Louis Solar	LU	201	NA	NA	NA
12	Tacoma, City of	SF	WSPP-1	NA	NA	NA
13	Tenaska Power Services	SF	WSPP-1	NA	NA	NA
14	The Energy Authority	SF	WSPP-1	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Thomas Creek Solar	LU	201	NA	NA	NA
2	Tickle Creek	LU	201	NA	NA	NA
3	TransAlta Energy Marketing	SF	PGE-11	NA	NA	NA
4	TransCanada Energy Marketing	SF	WSPP-1	NA	NA	NA
5	Turlock Irrigation District	SF	WSPP-1	NA	NA	NA
6	Utah Municipal Power Systems	SF	WSPP-1	NA	NA	NA
7	Vitol Inc.	SF	WSPP-1	NA	NA	NA
8	Volcano Solar	LU	WSPP-1	NA	NA	NA
9	VON FAMILY LTD PARTNERSHIP	LU	WSPP-1	NA	NA	NA
10	Warm Springs Power Enterprises	LU	WSPP-1	NA	NA	NA
11	WAPA - Upper Great Plains Region	SF	WSPP-1	NA	NA	NA
12	Westar Energy	LU	201	NA	NA	NA
13	Yamhill Creek Solar	LU	Yamhill	NA	NA	NA
14	Yamhill Solar	LU	Yamhill	NA	NA	NA
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Load Balance Energy	OS	OATT	NA	NA	NA
2	Country Village Estates	OS	201	NA	NA	NA
3	Domaine Drouhin	OS	201	NA	NA	NA
4	Lake Oswego Corporation	OS	201	NA	NA	NA
5	Minikahada Hydropower Co	OS	201	NA	NA	NA
6	Starbuck Properties	OS	201	NA	NA	NA
7	Solar Payment Option	OS	215-217	NA	NA	NA
8	Tualatin Valley Water Dist	OS	201	NA	NA	NA
9	Oregon Energy Fund	OS	203	NA	NA	NA
10	Load Curtailment Program			NA	NA	NA
11	Margin on Electric Financials			NA	NA	NA
12	Reserve Trading Credit Risk			NA	NA	NA
13	Green Power			NA	NA	NA
14	REC Retirement Expense			NA	NA	NA
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Carbon Allowance Expense			NA	NA	NA
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
11,400				1,258,118		1,258,118	1
2,537							2
245,177				9,571,125		9,571,125	3
198,694				12,589,022		12,589,022	4
			2,910,000			2,910,000	5
35,800				3,464,654		3,464,654	6
103,067				1,886,532		1,886,532	7
1,858				128,702		128,702	8
1,817				180,439		180,439	9
797,948				15,059,490		15,059,490	10
1,610				117,469		117,469	11
4,149				193,054		193,054	12
415				14,010		14,010	13
2,986				192,585		192,585	14
7,811,844			3,252,000	282,437,453	-4,231,871	281,457,582	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,160,022				36,093,660		36,093,660	1
1,549,310				62,840,522		62,840,522	2
				16,455		16,455	3
78,828				2,216,081		2,216,081	4
42,795				730,341		730,341	5
1,586				49,394		49,394	6
800				108,000		108,000	7
3,363				81,218		81,218	8
				8,450		8,450	9
18,539				821,215		821,215	10
64,496				1,290,457		1,290,457	11
414,829				15,843,215		15,843,215	12
40,617				1,506,803		1,506,803	13
800				23,800		23,800	14
7,811,844			3,252,000	282,437,453	-4,231,871	281,457,582	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					-258,000	-258,000	1
51,462				1,542,336		1,542,336	2
3,467				209,015		209,015	3
50				-1,090		-1,090	4
57,526				3,768,918		3,768,918	5
			342,000			342,000	6
8,865				202,925		202,925	7
57,920				1,687,559		1,687,559	8
76,784				3,846,674		3,846,674	9
48				1,652		1,652	10
17,195				870,746		870,746	11
2,039				107,303		107,303	12
1,628				113,651		113,651	13
78,879				3,009,558		3,009,558	14
7,811,844			3,252,000	282,437,453	-4,231,871	281,457,582	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
46,347				2,405,759		2,405,759	1
76,320				3,276,920		3,276,920	2
21,114				628,489		628,489	3
-103,687							4
70				2,076		2,076	5
3,698				186,463		186,463	6
1,020				14,814		14,814	7
21,442				17,340		17,340	8
193				-35,546		-35,546	9
5,012				132,211		132,211	10
				2,197		2,197	11
9,992				940,403		940,403	12
46,328				3,552,118		3,552,118	13
43,825				1,589,652		1,589,652	14
7,811,844			3,252,000	282,437,453	-4,231,871	281,457,582	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
26,425				2,167,307		2,167,307	1
51,341				1,125,522		1,125,522	2
175,795				9,833,540		9,833,540	3
24,800				747,768		747,768	4
680				11,245		11,245	5
316,624				10,733,145		10,733,145	6
316,624				10,733,145		10,733,145	7
44				1,522		1,522	8
197,775				6,777,301		6,777,301	9
144,507				4,796,760		4,796,760	10
2				17,943		17,943	11
772				36,410		36,410	12
148,778				3,787,136		3,787,136	13
102,680				4,261,478		4,261,478	14
7,811,844			3,252,000	282,437,453	-4,231,871	281,457,582	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,840				91,246		91,246	1
3,755				126,548		126,548	2
17,220				373,580		373,580	3
3,832				192,738		192,738	4
3,865				192,623		192,623	5
3,556				161,348		161,348	6
3,521				173,054		173,054	7
3,832				185,076		185,076	8
3,278				255,527		255,527	9
173				4,866		4,866	10
54				2,228		2,228	11
114,154				1,688,262		1,688,262	12
4,351				32,397		32,397	13
47,441				993,469		993,469	14
7,811,844			3,252,000	282,437,453	-4,231,871	281,457,582	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
134				17,203		17,203	1
99				3,435		3,435	2
227,653				5,795,347		5,795,347	3
850				30,850		30,850	4
17,129				656,656		656,656	5
				-2,436		-2,436	6
6,800				234,420		234,420	7
463				19,527		19,527	8
83				8,988		8,988	9
477,735				21,600,592		21,600,592	10
1							11
800				22,600		22,600	12
2,167				4,440		4,440	13
1,297				138,218		138,218	14
7,811,844			3,252,000	282,437,453	-4,231,871	281,457,582	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
32,730							1
6				478		478	2
118				9,149		9,149	3
127				11,121		11,121	4
155				11,896		11,896	5
23				2,266		2,266	6
12,637							7
87				12,565		12,565	8
51					56,455	56,455	9
					-3,471	-3,471	10
					-22,524,519	-22,524,519	11
					4,690,762	4,690,762	12
					16,074,058	16,074,058	13
					555,028	555,028	14
7,811,844			3,252,000	282,437,453	-4,231,871	281,457,582	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					-2,822,184	-2,822,184	1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
7,811,844			3,252,000	282,437,453	-4,231,871	281,457,582	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

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

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

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

Resource Adequecy Refund

Schedule Page: 326.3 Line No.: 4 Column: b

Colstrip Nonrunning Station Services: power sent to Northwestern Corp to keep Colstrip lights and other systems running.

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

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

Schedule Page: 326.7 Line No.: 2 Column: b

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

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

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

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

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

Schedule Page: 326.7 Line No.: 5 Column: b

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

Schedule Page: 326.7 Line No.: 6 Column: b

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

Schedule Page: 326.7 Line No.: 7 Column: b

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

Schedule Page: 326.7 Line No.: 8 Column: b

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

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

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

Schedule Page: 326.7 Line No.: 10 Column: l

Load Curtailment Program.

Schedule Page: 326.7 Line No.: 11 Column: l

Margin on electric financial transactions.

Schedule Page: 326.7 Line No.: 12 Column: l

Reserve for trading credit risk.

Schedule Page: 326.7 Line No.: 13 Column: l

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

Schedule Page: 326.7 Line No.: 14 Column: l

Expense of annual REC retirement to meet RPS compliance.

Schedule Page: 326.8 Line No.: 1 Column: l

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	3 Phases Renewables LLC	Bonneville Power Administration	Portland General Electric	FNO
2	Avangrid Renewables, LLC	Bonneville Power Administration	Portland General Electric	FNO
3	Avista Corp	Bonneville Power Administration	California Independent System Ope	LFP
4	Avista Corp	Bonneville Power Administration	California Independent System Ope	NF
5	Avista Corp	California Independent System Ope	Bonneville Power Administration	NF
6	Avista Corp	California Independent System Ope	Bonneville Power Administration	OS
7	BPA Power Business Line	Bonneville Power Administration	Portland General Electric	FNO
8	BPA Power Business Line	Bonneville Power Administration	West Oregon Total Actual	OLF
9	BPA Power Business Line	Bonneville Power Administration	Other Total Actual	OLF
10	BPA Power Business Line	Bonneville Power Administration	CANBY Total Actual	OLF
11	BPA Power Business Line	Bonneville Power Administration	CRPUD Total Actual	OLF
12	Brookfield Energy Marketing	Bonneville Power Administration	California Independent System Ope	NF
13	Brookfield Renewable Trading and Marketing	Bonneville Power Administration	California Independent System Ope	NF
14	Calpine Energy Services	Bonneville Power Administration	Portland General Electric	FNO
15	Canadian Wood Products - Montreal INC			NF
16	Conoco Phillips Inc.	Bonneville Power Administration	California Independent System Ope	NF
17	Constellation New Energy	Bonneville Power Administration	Balancing Authority of Northern C	LFP
18	Constellation New Energy	Bonneville Power Administration	California Independent System Ope	LFP
19	Constellation New Energy	Bonneville Power Administration	California Independent System Ope	LFP
20	Constellation New Energy	Balancing Authority of Northern C	Bonneville Power Administration	NF
21	Constellation New Energy	Bonneville Power Administration	California Independent System Ope	NF
22	Constellation New Energy	California Independent System Ope	Bonneville Power Administration	NF
23	Constellation New Energy	Bonneville Power Administration	Portland General Electric	FNO
24	Constellation New Energy	California Independent System Ope	Bonneville Power Administration	OS
25	EDF Trading North America LLC	Bonneville Power Administration	California Independent System Ope	NF
26	Macquarie Energy LLC	Bonneville Power Administration	California Independent System Ope	NF
27	Macquarie Energy LLC	California Independent System Ope	Bonneville Power Administration	NF
28	Mag Energy Solutions	Bonneville Power Administration	California Independent System Ope	NF
29	Morgan Stanley Capital Group	Bonneville Power Administration	Balancing Authority of Northern C	LFP
30	Morgan Stanley Capital Group	Bonneville Power Administration	California Independent System Ope	LFP
31	Morgan Stanley Capital Group	Bonneville Power Administration	Balancing Authority of Northern C	NF
32	Morgan Stanley Capital Group	Bonneville Power Administration	California Independent System Ope	NF
33	Morgan Stanley Capital Group	California Independent System Ope	Bonneville Power Administration	NF
34	Pacificorp West	PacifiCorp	Portland General Electric	OLF
	TOTAL			

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Pacificorp West	Portland General Electric	Portland General Electric	LFP
2	Pacificorp West	Portland General Electric	Portland General Electric	NF
3	Powerex Inc.	Bonneville Power Administration	Balancing Authority of Northern C	LFP
4	Powerex Inc.	Bonneville Power Administration	California Independent System Ope	LFP
5	Powerex Inc.	California Independent System Ope	Bonneville Power Administration	LFP
6	Powerex Inc.	Bonneville Power Administration	Balancing Authority of Northern C	NF
7	Powerex Inc.	Bonneville Power Administration	California Independent System Ope	NF
8	Powerex Inc.	California Independent System Ope	Bonneville Power Administration	NF
9	Powerex Inc.	California Independent System Ope	Bonneville Power Administration	OS
10	PUD No. 1 of Cowlitz County	Bonneville Power Administration	California Independent System Ope	LFP
11	PUD No. 1 of Franklin County	Bonneville Power Administration	California Independent System Ope	LFP
12	PUD No. 1 of Klickitat County	Bonneville Power Administration	California Independent System Ope	LFP
13	PUD No. 1 of Lewis County	Bonneville Power Administration	California Independent System Ope	LFP
14	Puget Sound Energy Marketing	California Independent System Ope	Bonneville Power Administration	NF
15	Seattle City Light	Balancing Authority of Northern C	Bonneville Power Administration	NF
16	Seattle City Light	Bonneville Power Administration	Balancing Authority of Northern C	NF
17	Seattle City Light	Bonneville Power Administration	California Independent System Ope	NF
18	Shell Energy North America	Bonneville Power Administration	Balancing Authority of Northern C	LFP
19	Shell Energy North America	Bonneville Power Administration	California Independent System Ope	LFP
20	Shell Energy North America	Bonneville Power Administration	California Independent System Ope	LFP
21	Shell Energy North America	Balancing Authority of Northern C	Bonneville Power Administration	NF
22	Shell Energy North America	Bonneville Power Administration	Balancing Authority of Northern C	NF
23	Shell Energy North America	Bonneville Power Administration	California Independent System Ope	NF
24	Shell Energy North America	California Independent System Ope	Bonneville Power Administration	NF
25	Shell Energy North America	Bonneville Power Administration	Portland General Electric	FNO
26	Shell Energy North America	Balancing Authority of Northern C	Bonneville Power Administration	OS
27	Shell Energy North America	California Independent System Ope	Bonneville Power Administration	OS
28	Tenaska Power Services	Bonneville Power Administration	California Independent System Ope	NF
29	The Energy Authority	Bonneville Power Administration	Balancing Authority of Northern C	LFP
30	The Energy Authority	Bonneville Power Administration	California Independent System Ope	LFP
31	The Energy Authority	Balancing Authority of Northern C	Bonneville Power Administration	NF
32	The Energy Authority	Bonneville Power Administration	Balancing Authority of Northern C	NF
33	The Energy Authority	Bonneville Power Administration	California Independent System Ope	NF
34	The Energy Authority	California Independent System Ope	Bonneville Power Administration	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	The Energy Authority	Balancing Authority of Northern C	Bonneville Power Administration	OS
2	The Energy Authority	California Independent System Ope	Bonneville Power Administration	OS
3	Transalta Energy Marketing (US) Inc.	Bonneville Power Administration	Balancing Authority of Northern C	NF
4	Transalta Energy Marketing (US) Inc.	Bonneville Power Administration	California Independent System Ope	NF
5	Transalta Energy Marketing (US) Inc.	California Independent System Ope	Bonneville Power Administration	NF
6	Turlock Irrigation District	Bonneville Power Administration	Balancing Authority of Northern C	NF
7	Turlock Irrigation District	Bonneville Power Administration	California Independent System Ope	NF
8	Accrual			AD
9				
10				
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31				
32				
33				
34				
	TOTAL			

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
7	BPAT.PGE	PGE	16	10,398	4,309	1
7	BPAT.PGE	PGE	329	127,772	135,054	2
7	JohnDay	Malin500		445,641	445,641	3
8	JohnDay	Malin500		543	543	4
8	Malin500	JohnDay		1,658	1,658	5
8	Malin500	JohnDay		3,166	3,166	6
7	BPAT.PGE	PGE	79	41,437	40,986	7
72	BPAT.PGE	Various Subs		13,704	12,967	8
72	BPAT.PGE	Various Subs		6,846	6,478	9
72	BPAT.PGE	Various Subs		185,316	175,349	10
72	BPAT.PGE	Various Subs		235,040	222,398	11
8	JohnDay	Malin500		1,948	1,948	12
8	JohnDay	Malin500		755	755	13
7	BPAT.PGE	PGE	2,451	1,443,573	1,411,635	14
						15
8	JohnDay	Malin500		1	1	16
7	JohnDay	CaptainJack		160	160	17
7	JohnDay	COBH		160	160	18
7	JohnDay	Malin500		74,143	74,143	19
8	CaptainJack	JohnDay		983	983	20
8	JohnDay	Malin500		1,393	1,393	21
8	Malin500	JohnDay		4,647	4,647	22
7	BPAT.PGE	PGE	840	452,122	457,832	23
8	Malin500	JohnDay		328	328	24
8	JohnDay	Malin500		30	30	25
8	JohnDay	Malin500		3,876	3,876	26
8	Malin500	JohnDay		865	865	27
8	JohnDay	Malin500		90	90	28
7	JohnDay	CaptainJack		61,069	61,069	29
7	JohnDay	Malin500		1,204	1,204	30
8	JohnDay	CaptainJack		1,159	1,159	31
8	JohnDay	Malin500		3,548	3,548	32
8	Malin500	JohnDay		948	948	33
Exchange	PACW.PGE	PGE		4,713	4,353	34
			4,103	**6,205,786**	**6,140,944**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
7	RoundButte	REDMOND		12,258	12,258	1
8	RoundButte	REDMOND		1,413	1,413	2
7	JohnDay	CaptainJack		159,191	159,191	3
7	JohnDay	Malin500		1,081,388	1,081,388	4
7	Malin500	JohnDay		328,197	328,197	5
8	JohnDay	CaptainJack		46	46	6
8	JohnDay	Malin500		1,302	1,302	7
8	Malin500	JohnDay		1,197	1,197	8
8	Malin500	JohnDay		1,998	1,998	9
7	JohnDay	COBH				10
7	JohnDay	COBH				11
7	JohnDay	COBH				12
7	JohnDay	COBH				13
8	Malin500	JohnDay		444	444	14
8	CaptainJack	JohnDay		200	200	15
8	JohnDay	CaptainJack		896	896	16
8	JohnDay	Malin500		486	486	17
7	JohnDay	CaptainJack		170,693	170,693	18
7	JohnDay	COBH		800	800	19
7	JohnDay	Malin500		901,415	901,415	20
8	CaptainJack	JohnDay		100	100	21
8	JohnDay	CaptainJack		8,457	8,457	22
8	JohnDay	Malin500		72,057	72,057	23
8	Malin500	JohnDay		680	680	24
7	BPAT.PGE	PGE	388	210,131	194,849	25
8	CaptainJack	JohnDay		693	693	26
8	Malin500	JohnDay		3,532	3,532	27
8	JohnDay	Malin500		150	150	28
7	JohnDay	CaptainJack		19,026	19,026	29
7	JohnDay	Malin500		63,756	63,756	30
8	CaptainJack	JohnDay		247	247	31
8	JohnDay	CaptainJack		1,617	1,617	32
8	JohnDay	Malin500		9,437	9,437	33
8	Malin500	JohnDay		619	619	34
			4,103	**6,205,786**	**6,140,944**	

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
8	CaptainJack	JohnDay		1,255	1,255	1
8	Malin500	JohnDay		6,216	6,216	2
8	JohnDay	CaptainJack		129	129	3
8	JohnDay	Malin500		10,883	10,883	4
8	Malin500	JohnDay		4,175	4,175	5
8	JohnDay	CaptainJack		445	445	6
8	JohnDay	Malin500		1,021	1,021	7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
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						28
						29
						30
						31
						32
						33
						34
			4,103	**6,205,786**	**6,140,944**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
10,293			10,293	1
203,787			203,787	2
	642,900		642,900	3
	1,308		1,308	4
	3,995		3,995	5
				6
47,388			47,388	7
	80,064		80,064	8
	24,214		24,214	9
	310,833		310,833	10
	31,895		31,895	11
	1,486		1,486	12
	1,282		1,282	13
1,591,923			1,591,923	14
	-39		-39	15
	1		1	16
	138		138	17
	138		138	18
	63,953		63,953	19
	1,265		1,265	20
	1,793		1,793	21
	5,982		5,982	22
529,485			529,485	23
				24
	22		22	25
	8,059		8,059	26
	1,798		1,798	27
	117		117	28
	62,977		62,977	29
	1,242		1,242	30
	1,494		1,494	31
	4,574		4,574	32
	1,222		1,222	33
		247,349	247,349	34
2,629,884	**5,557,677**	**2,251,360**	**10,438,921**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	82,691		82,691	1
	2,551		2,551	2
	249,243		249,243	3
	1,693,110		1,693,110	4
	513,852		513,852	5
	96		96	6
	2,723		2,723	7
	2,503		2,503	8
				9
	64,299		64,299	10
	64,299		64,299	11
	70,729		70,729	12
	70,729		70,729	13
	458		458	14
	242		242	15
	1,085		1,085	16
	588		588	17
	204,523		204,523	18
	959		959	19
	1,080,070		1,080,070	20
	126		126	21
	10,650		10,650	22
	90,742		90,742	23
	856		856	24
247,008			247,008	25
				26
				27
	191		191	28
	14,709		14,709	29
	49,291		49,291	30
	298		298	31
	1,949		1,949	32
	11,374		11,374	33
	746		746	34
2,629,884	**5,557,677**	**2,251,360**	**10,438,921**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
				1
				2
	152		152	3
	12,790		12,790	4
	4,907		4,907	5
	435		435	6
	998		998	7
		2,004,011	2,004,011	8
				9
				10
				11
				12
				13
				14
				15
				16
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				31
				32
				33
				34
2,629,884	**5,557,677**	**2,251,360**	**10,438,921**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Schedule Page: 328 Line No.: 3 Column: d
Contract with Avista Corporation Washington Water Power Division expires 1/1/2023.
Schedule Page: 328 Line No.: 6 Column: d
Represents non-billed redirected MWHs of Avista Corporation Washington Water Power's service.
Schedule Page: 328 Line No.: 8 Column: d
Contract with Bonneville Power Administration continues until temrinated.
Schedule Page: 328 Line No.: 9 Column: d
Contract with Bonneville Power Administration continues until temrinated.
Schedule Page: 328 Line No.: 10 Column: d
Contract with Bonneville Power Administration continues until temrinated.
Schedule Page: 328 Line No.: 11 Column: d
Contract with Bonneville Power Administration continues until temrinated.
Schedule Page: 328 Line No.: 17 Column: d
Contract with Constellation New Energy expires 1/1/2034.
Schedule Page: 328 Line No.: 18 Column: d
Contract with Constellation New Energy expires 1/1/2034.
Schedule Page: 328 Line No.: 19 Column: d
Contract with Constellation New Energy expires 1/1/2034.
Schedule Page: 328 Line No.: 24 Column: d
Represents non-billed redirected MWHs of Constallation New Energy's service.
Schedule Page: 328 Line No.: 29 Column: d
Contract with Morgan Stanley Capital Group Inc expires 1/1/2034.
Schedule Page: 328 Line No.: 30 Column: d
Contract with Morgan Stanley Capital Group Inc expires 1/1/2034.
Schedule Page: 328 Line No.: 34 Column: d
Exchange agreement with Pacificorp.
Schedule Page: 328.1 Line No.: 1 Column: d
Contract with Pacificorp West expires 4/1/2022.
Schedule Page: 328.1 Line No.: 3 Column: d
Contract with Powerex Inc expires 1/1/2022.
Schedule Page: 328.1 Line No.: 4 Column: d
Contract with Powerex Inc expires 1/1/2022.
Schedule Page: 328.1 Line No.: 5 Column: d
Contract with Powerex Inc expires 1/1/2022.
Schedule Page: 328.1 Line No.: 9 Column: d
Represents non-billed redirected MWHs of Powerex Inc's service.
Schedule Page: 328.1 Line No.: 10 Column: d
Contract with PUD No. 1 of Cowlitz County expires 1/1/2034.
Schedule Page: 328.1 Line No.: 11 Column: d
Contract with PUD No. 1 of Franklin County expires 1/1/2034.
Schedule Page: 328.1 Line No.: 12 Column: d
Contract with PUD No. 1 of Klickitat County expires 1/1/2034.
Schedule Page: 328.1 Line No.: 13 Column: d
Contract with PUD No. 1 of Lewis County expires 1/1/2034.
Schedule Page: 328.1 Line No.: 18 Column: d
Contract with Shell Energy North America expires 12/31/2021.
Schedule Page: 328.1 Line No.: 19 Column: d
Contract with Shell Energy North America expires 12/31/2021.
Schedule Page: 328.1 Line No.: 20 Column: d
Contract with Shell Energy North America expires 12/31/2021.
Schedule Page: 328.1 Line No.: 26 Column: d
Represents non-billed redirected MWHs of Shell Energy North America's service.
Schedule Page: 328.1 Line No.: 27 Column: d

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2019/Q4

FOOTNOTE DATA

Represents non-billed redirected MWHs of Shell Energy North America's service.

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

Contract with The Energy Authority expires 1/1/2034.

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

Contract with The Energy Authority expires 1/1/2034.

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

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

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

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

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

Represents the difference between actual transmission revenue for the year, as reflected on the individual line items within this schedule, and the accruals credited during the year (including financial settlement of electrical losses associated with the use of the transmission system) to FERC Account 456.1, Revenues from Transmission of Electricity for Others.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

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

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
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39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Avista Corp	NF	4,319	4,319		24,921		24,921
2	Bonneville Power Admin	LFP			64,668,464			64,668,464
3	Bonneville Power Admin	OS	157,045	157,045			16,293,317	16,293,317
4	Bonneville Power Admin	SFP	33,311	33,311		49,725		49,725
5	Bonneville Power Admin	NF	3,064	3,064		7,268		7,268
6	Bonneville Power Admin	AD					-751	-751
7	Calpine Energy Services	LFP	76,067	76,067		230,761		230,761
8	Columbia River PUD	SFP	12	12		17,895		17,895
9	DET - Gamesa	OS					-1,021,872	-1,021,872
10	EDF Renewable N.America	OS					-48,175	-48,175
11	Eugene Water & Electric	LFP	24	24		107,765		107,765
12	Idaho Power Company	NF	27,600	27,600		165,267		165,267
13	McMinnville Water & Lig	LFP	640	640		9,421		9,421
14	Montana, State of	OS					2,438,782	2,438,782
15	NorthWestern Energy	NF	19,657	19,657		93,219		93,219
16	PacifiCorp	OS					112,708	112,708
	TOTAL		405,691	405,691	64,668,464	1,119,410	17,774,009	83,561,883

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	PacifiCorp	SFP	76,320	76,320		399,369		399,369
2	Powerex	SFP				554		554
3	Puget Sound Energy	NF	6,332	6,332		11,571		11,571
4	Seattle City Light	NF	1,300	1,300		1,524		1,524
5	Snohomish County PUD	SFP				150		150
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		405,691	405,691	64,668,464	1,119,410	17,774,009	83,561,883

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

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

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

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

Represents Bonneville Power Administration Ancillary Transmission Services.

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

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

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

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

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

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

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

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

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

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

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

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

Schedule Page: 332 Line No.: 16 Column: g

Represents PacifiCorp's Linneman Transmission Services.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	3,556,924
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	2,450,319
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	2,205,670
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Involuntary Severance	6,068,626
7	Directors Pension	191,275
8	Directors Fees and Expenses	253,802
9	Directors and Officers Expenses	2,168,389
10	Misc. Admin expenses	322,037
11	Colstrip - PPL Montana	1,214,680
12		
13		
14		
15		
16		
17		
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46	TOTAL	18,431,722

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			64,406,427		64,406,427
2	Steam Production Plant	34,801,133	6,315,170			41,116,303
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	22,094,567	69			22,094,636
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	80,263,778	566,832			80,830,610
7	Transmission Plant	12,520,888	1			12,520,889
8	Distribution Plant	118,051,775	5,527			118,057,302
9	Regional Transmission and Market Operation					
10	General Plant	39,966,930	99			39,967,029
11	Common Plant-Electric					
12	TOTAL	307,699,071	6,887,698	64,406,427		378,993,196

B. Basis for Amortization Charges

Five year and ten year amortization of computer software.

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Applied depreciation						
13	rates for all assets						
14	effective 1/1/2018 per						
15	Order 17-365 in						
16	OPUC Docket UM-1809.						
17							
18							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	FERC-NERC Reliability		167,549	167,549	
2	Docket RM06-16				
3					
4	FERC-NERC Reliability		141,328	141,328	
5	Docket RM06-22				
6					
7	FERC-NERC Reliability		74,952	74,952	
8	Docket EL19-13				
9					
10	FERC matters less than $25,000		15,860	15,860	
11					
12	OPUC Docket UM 1805		134,672	134,672	
13					
14	OPUC Docket UM 1931		298,437	298,437	
15					
16	OPUC Docket UM 1967		195,434	195,434	
17					
18	OPUC Docket UM 1971		201,219	201,219	
19					
20	OPUC Docket UM 1894		94,137	94,137	
21					
22	OPUC Docket UM 1817		39,329	39,329	
23					
24	OPUC Docket UM 1994		64,411	64,411	
25					
26	OPUC Docket UM 1995		32,566	32,566	
27					
28	OPUC Docket UM 2009		296,520	296,520	
29					
30	OPUC matters less than $25,000		247,391	247,391	
31					
32	Unassigned Non-Doc Matters		322,460	322,460	
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL		2,326,265	2,326,265	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
	928	167,549					1
							2
							3
	928	141,328					4
							5
							6
	928	74,952					7
							8
							9
	928	15,860					10
							11
	928	134,672					12
							13
	928	298,437					14
							15
	928	195,434					16
							17
	928	201,219					18
							19
	928	94,137					20
							21
	928	39,329					22
							23
	928	64,411					24
							25
	928	32,566					26
							27
	928	296,520					28
							29
	928	247,391					30
							31
	928	322,460					32
							33
							34
							35
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		2,326,265					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

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

Line No.	Classification (a)	Description (b)
1	A(1)	Electric R, D & D Performed Internally - Generation
2	A(1)(d)	Nuclear
3	A(1)(e)	Unconventional Generation
4	A(2)	Electric R, D & D Performed Internally - Transmission
5	A(3)	Electric R, D & D Performed Internally - Distribution
6	A(5)	Electric R, D & D Performed Internally - Environment
7	A(6)	Electric R, D & D Performed Internally - Other
8	B(1)	Electric R, D & D Performed Externally
9		
10		
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
35,000		930.2	35,000		3
50,000		930.2	50,000		4
475,174		930.2	475,174		5
117,779		930.2	117,779		6
15,000		930.2	15,000		7
	1,757,366	930.2	1,757,366		8
					9
					10
					11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
692,953	1,757,366		2,450,319		24
					25
					26
					27
					28
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					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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	33,102,709		
4	Transmission	6,135,299		
5	Regional Market			
6	Distribution	17,595,529		
7	Customer Accounts	29,467,234		
8	Customer Service and Informational	6,586,359		
9	Sales			
10	Administrative and General	37,631,810		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	130,518,940		
12	Maintenance			
13	Production	13,387,503		
14	Transmission	1,073,190		
15	Regional Market			
16	Distribution	24,610,564		
17	Administrative and General	1,244,734		
18	TOTAL Maintenance (Total of lines 13 thru 17)	40,315,991		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	46,490,212		
21	Transmission (Enter Total of lines 4 and 14)	7,208,489		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	42,206,093		
24	Customer Accounts (Transcribe from line 7)	29,467,234		
25	Customer Service and Informational (Transcribe from line 8)	6,586,359		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	38,876,544		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	170,834,931	27,318,092	198,153,023
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			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	170,834,931	27,318,092	198,153,023
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	114,040,513	4,710,732	118,751,245
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	114,040,513	4,710,732	118,751,245
72	Plant Removal (By Utility Departments)			
73	Electric Plant	487,888	18,292	506,180
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	487,888	18,292	506,180
77	Other Accounts (Specify, provide details in footnote):			
78	Other Income and Deductions	1,520,282	134,691	1,654,973
79	Co-Owner Shares of Generating Facilities	5,292,416	215,390	5,507,806
80	Other	5,318,748	310,274	5,629,022
81	Payroll Allocated	32,707,471	-32,707,471	
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	44,838,917	-32,047,116	12,791,801
96	TOTAL SALARIES AND WAGES	330,202,249		330,202,249

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

COMMON UTILITY PLANT AND EXPENSES

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/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)	13,998,657	1,661,952	10,862,397	36,093,660
3	Net Sales (Account 447)	12,163,324	7,985,145	24,059,237	62,971,339
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
10					
11					
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32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	26,161,981	9,647,097	34,921,634	99,064,999

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	157,045	MWH	15,091,581	6,098,774	MWH	159,137
2	Reactive Supply and Voltage				4,024,978	MWH	129,759
3	Regulation and Frequency Response				4,023,448	MWH	289,207
4	Energy Imbalance	52,574	MWH	2,493,256	91,935	MWH	1,763,557
5	Operating Reserve - Spinning				3,361	MW	337,529
6	Operating Reserve - Supplement				3,361	MW	337,529
7	Other						
8	Total (Lines 1 thru 7)	209,619		17,584,837	14,245,857		3,016,718

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

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

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

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

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

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

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

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

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

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM: PGE

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	4,386	15	18	2,903	271	2,344	83	4,664	2
2	February	4,413	26	19	3,130	275	2,344	80	4,864	304
3	March	4,260	4	19	2,981	264	2,344	57	4,764	156
4	Total for Quarter 1				9,014	810	7,032	220	14,292	462
5	April	3,803	7	13	2,118	244	2,344	49	4,664	
6	May	4,357	30	18	2,323	296	2,344	56	4,814	
7	June	4,801	12	18	3,442	320	2,344	81	5,017	242
8	Total for Quarter 2				7,883	860	7,032	186	14,495	242
9	July	4,707	26	19	3,062	310	2,344	68	4,717	15
10	August	4,866	27	18	3,279	322	2,344	88	4,617	375
11	September	4,572	3	18	2,892	309	2,344	62	4,617	95
12	Total for Quarter 3				9,233	941	7,032	218	13,951	485
13	October	4,501	29	11	2,568	275	2,344	67	4,167	303
14	November	4,366	30	16	2,617	233	2,344	57	4,190	356
15	December	4,554	15	20	2,716	249	2,344	74	3,130	108
16	Total for Quarter 4				7,901	757	7,032	198	11,487	767
17	Total Year to Date/Year				34,031	3,368	28,128	822	54,225	1,956

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM: Colstrip

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	284	6	4			307			
2	February	284	21	24			307			
3	March	290	26	16			307			
4	Total for Quarter 1						921			
5	April	285	2	5			307			
6	May	265	15	23			307			
7	June	292	21	21			307			
8	Total for Quarter 2						921			
9	July	284	4	16			307			
10	August	254	12	8			307			
11	September	214	10	5			307			
12	Total for Quarter 3						921			
13	October	271	12	13			307			
14	November	176	23	13			307			
15	December	279	22	6			307			
16	Total for Quarter 4						921			
17	Total Year to Date/Year						3,684			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

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

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	4,416,247
4	Nuclear	
5	Hydro-Conventional	1,407,437
6	Hydro-Pumped Storage	
7	Other	10,047,906
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	15,871,590
10	Purchases	7,811,844
11	Power Exchanges:	
12	Received	
13	Delivered	
14	Net Exchanges (Line 12 minus line 13)	
15	Transmission For Other (Wheeling)	
16	Received	6,205,786
17	Delivered	6,140,944
18	Net Transmission for Other (Line 16 minus line 17)	64,842
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	23,748,276

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	17,304,691
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	5,267,311
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	31,674
27	Total Energy Losses	1,144,600
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	23,748,276

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

MONTHLY PEAKS AND OUTPUT

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

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	2,108,036	401,544	3,204	15	19
30	February	1,873,806	217,778	3,422	7	8
31	March	1,853,275	263,830	3,405	4	8
32	April	1,678,373	303,787	2,702	15	8
33	May	1,572,809	211,286	2,774	10	18
34	June	1,805,513	427,160	3,765	12	17
35	July	2,165,686	665,829	3,432	26	18
36	August	2,344,765	759,634	3,724	28	18
37	September	2,134,612	740,730	3,249	5	18
38	October	1,969,544	479,583	3,131	30	8
39	November	2,007,837	455,952	3,165	26	18
40	December	2,169,178	428,910	3,248	18	18
41	TOTAL	23,683,434	5,356,023			

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

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

In addition to the generation from the Beaver, Port Westward 1, Port Westward 2, Coyote Springs, and Carty generation plants (as shown on page 403), and generation from PGE's solar generation facilities (as shown on page 410), other generation includes 1,706,278 megawatt hours of net wind energy from PGE's Biglow Canyon Wind Farm and Tucannon River Wind Farm.

Actual gross wind generation from the two wind farms was 1,717,116 megawatt hours.

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

In-service production cost at 12/31/2019: $940,536,985
Total installed capacity: 450 megawatts
Operations and maintenance expenses for 2019: $16,576,790

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

In-service production cost at 12/31/2019: $485,795,936
Total installed capacity: 267 megawatts
Operations and maintenance expenses for 2019: $12,332,161

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

PGE has ownership in a 5Mw storage battery (Salem Smart Power Center) with a FERC 101 Plant-in-service balance of $384,933 as of 12/31/2019, recorded to FERC 363 - Storage Battery Equipment, Distribution. This battery is located in the Salem, Oregon area and is connected to PGE's Oxford Substation. PGE recorded expenses for 2019 to FERC 584.1 - Operations of Energy Storage Equipment $711 and FERC 592.2 - Maintenance of Energy Storage Equipment $35,973. Line loss includes 1.00 MWh of Energy stored in this battery at year end.

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	Plant Name: *Boardman* (b)	Plant Name: *Boardman (PGE Share)* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional
3	Year Originally Constructed	1980	1980
4	Year Last Unit was Installed	1980	1980
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	642.20	578.00
6	Net Peak Demand on Plant - MW (60 minutes)	587	0
7	Plant Hours Connected to Load	5713	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	575	0
10	When Limited by Condenser Water	575	0
11	Average Number of Employees	78	0
12	Net Generation, Exclusive of Plant Use - KWh	2557844000	2302723000
13	Cost of Plant: Land and Land Rights	939463	832853
14	Structures and Improvements	154301395	141673099
15	Equipment Costs	578344789	514246873
16	Asset Retirement Costs	46996196	41950188
17	Total Cost	780581843	698703013
18	Cost per KW of Installed Capacity (line 17/5) Including	1215.4809	1208.8287
19	Production Expenses: Oper, Supv, & Engr	2578067	2146169
20	Fuel	66241790	59539251
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	7494606	6510879
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	9512044	8529900
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	418142	371890
30	Maintenance of Structures	319469	283618
31	Maintenance of Boiler (or reactor) Plant	1032705	911888
32	Maintenance of Electric Plant	8368445	7372329
33	Maintenance of Misc Steam (or Nuclear) Plant	393566	345745
34	Total Production Expenses	96358834	86011669
35	Expenses per Net KWh	0.0377	0.0374

Line No.	Item (a)	(b)			(c)		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil				
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels				
38	Quantity (Units) of Fuel Burned	1499340	9021	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8699	138800	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	43.753	96.428	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	43.621	93.088	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.507	15.968	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.026	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10198.244	0.000	0.000	0.000	0.000	0.000

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

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

Line No.	Item (a)	Plant Name: (b)	Plant Name: *Colstrip* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear		Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	311.20
6	Net Peak Demand on Plant - MW (60 minutes)	0	0
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	0	2113524000
13	Cost of Plant: Land and Land Rights	0	3328772
14	Structures and Improvements	0	117227390
15	Equipment Costs	0	359097000
16	Asset Retirement Costs	0	34030383
17	Total Cost	0	513683545
18	Cost per KW of Installed Capacity (line 17/5) Including	0	1650.6541
19	Production Expenses: Oper, Supv, & Engr	0	184532
20	Fuel	0	33978422
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	1995382
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	0	2573541
27	Rents	0	16802
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	529739
30	Maintenance of Structures	0	816130
31	Maintenance of Boiler (or reactor) Plant	0	5563924
32	Maintenance of Electric Plant	0	250940
33	Maintenance of Misc Steam (or Nuclear) Plant	0	590357
34	Total Production Expenses	0	46499769
35	Expenses per Net KWh	0.0000	0.0220

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

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

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Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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

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

Plant Name: *Beaver* (d)			Plant Name: *Port Westward 1* (e)			Plant Name: *Coyote Springs* (f)			Line No.
Gas & Steam Turbine			Gas & Steam Turbine			Gas & Steam Turbine			1
Outdoor			Outdoor			Outdoor			2
1974			2007			1995			3
2001			2007			1995			4
573.20			483.30			296.00			5
467			425			296			6
2313			7287			7257			7
0			0			0			8
533			421			270			9
0			0			0			10
47			27			31			11
499401000			2734708000			1774063000			12
24473			24473			0			13
38980475			42782157			11638385			14
225214633			242454424			190787502			15
2941318			231072			113193			16
267160899			285492126			202539080			17
466.0867			590.7141			684.2536			18
327560			537284			354052			19
13567675			74735820			23850533			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
1810141			2797517			1184545			25
4411584			2131884			1073181			26
217035			28586			0			27
0			0			0			28
1470186			220963			69436			29
190897			19720			104406			30
0			0			0			31
4403117			7489570			7996464			32
441184			60053			43463			33
26839379			88021397			34676080			34
0.0537			0.0322			0.0195			35
Gas	Oil		Gas	Oil		Gas	Oil		36
Mcf's	Barrels		Mcf's	Barrels		Mcf's	Barrels		37
4905546	3309	0	19366946	0	0	12754984	0	0	38
1019000	138690	0	1019000	138690	0	1019000	138690	0	39
0.745	88.686	0.000	3.211	0.000	0.000	1.409	0.000	0.000	40
2.696	103.939	0.000	3.859	0.000	0.000	1.870	0.000	0.000	41
2.645	17.878	0.000	3.786	0.000	0.000	1.834	0.000	0.000	42
0.026	0.000	0.000	0.027	0.000	0.000	0.013	0.000	0.000	43
10013.100	0.000	0.000	7219.100	0.000	0.000	7329.000	0.000	0.000	44

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

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Plant Name: *Port Westward 2* (d)			Plant Name: *Carty* (e)			Plant Name: (f)			Line No.
Reciprocating Engine			Gas & Steam Turbine						1
Outdoor			Outdoor						2
2014			2016						3
2014			2016						4
225.10			503.10			0.00			5
224			471			0			6
4065			7288			0			7
0			0			0			8
225			0			0			9
0			0			0			10
0			24			0			11
360261000			2969783000			0			12
0			0			0			13
42352598			40631269			0			14
248315796			427403856			0			15
647461			10434861			0			16
291315855			478469986			0			17
1294.1620			951.0435			0			18
20989			418343			0			19
12850484			46742870			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
578983			2529491			0			25
1511468			2316863			0			26
33347			0			0			27
0			0			0			28
766			91883			0			29
4126			146200			0			30
0			0			0			31
1565586			8220097			0			32
36843			270598			0			33
16602592			60736345			0			34
0.0461			0.0205			0.0000			35
Gas	Oil		Gas	Oil					36
Mcf's	Barrels		Mcf's	Barrels					37
3180789	0	0	33179976	0	0	0	0	0	38
1019000	138690	0	1019000	138690	0	0	0	0	39
2.976	0.000	0.000	0.811	0.000	0.000	0.000	0.000	0.000	40
4.040	0.000	0.000	1.409	0.000	0.000	0.000	0.000	0.000	41
3.963	0.000	0.000	1.382	0.000	0.000	0.000	0.000	0.000	42
0.036	0.000	0.000	0.016	0.000	0.000	0.000	0.000	0.000	43
9000.100	0.000	0.000	11388.900	0.000	0.000	0.000	0.000	0.000	44

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

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Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
0			0			0			17
0			0			0			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

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

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

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

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

Respondent is the principal owner (90% interest) and operator of the Boardman Plant. The other owner is Idaho Power Company (10%). Reported here are 100% costs and plant statistics, including shared and non-shared costs.

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

Respondent is the principal owner and operator of the Boardman Plant. Installed capacity in line 5c represents 90% share. Reported here are the respondent’s share of expenses incurred during the year and investment as of December 31, 2019, as appropriate. Details are reported in Page 402 col (b).

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

Based on January average temperature.

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

Based on January average temperature.

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

Based on January average temperature.

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

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

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

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

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

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

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

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

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

The Coyote Springs Plant uses gas extensively for generation with minimal oil usage. The Average BTU per KWH net generation reported is a composite heat rate for both fuels.

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

The Port Westward 2 Plant uses gas extensively for generation with minimal oil usage. The Average BTU per KWH net generation reported is a composite heat rate for both fuels.

Schedule Page: 402.1 Line No.: 44 Column: e1

The Carty Plant uses gas extensively for generation with minimal oil usage. The Average

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

BTU per KWH net generation reported is a composite heat rate for both fuels.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 2195 Plant Name: Faraday (b)	FERC Licensed Project No. 2195 Plant Name: North Fork (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of River;Storage	Run-of River
2	Plant Construction type (Conventional or Outdoor)	Conventional;Outdoor	Outdoor
3	Year Originally Constructed	1907	1958
4	Year Last Unit was Installed	1958	1958
5	Total installed cap (Gen name plate Rating in MW)	36.81	50.25
6	Net Peak Demand on Plant-Megawatts (60 minutes)	46	57
7	Plant Hours Connect to Load	4,574	8,755
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	46	58
10	(b) Under the Most Adverse Oper Conditions	5	7
11	Average Number of Employees	51	0
12	Net Generation, Exclusive of Plant Use - Kwh	80,249,000	132,755,000
13	Cost of Plant		
14	Land and Land Rights	33,434	377,100
15	Structures and Improvements	14,154,712	9,115,427
16	Reservoirs, Dams, and Waterways	32,440,590	86,489,850
17	Equipment Costs	9,747,911	13,423,655
18	Roads, Railroads, and Bridges	2,441,325	2,767,794
19	Asset Retirement Costs	90	6
20	TOTAL cost (Total of 14 thru 19)	58,818,062	112,173,832
21	Cost per KW of Installed Capacity (line 20 / 5)	1,597.8827	2,232.3151
22	Production Expenses		
23	Operation Supervision and Engineering	432,885	5,630
24	Water for Power	67,597	53,124
25	Hydraulic Expenses	1,092,889	692,341
26	Electric Expenses	514,979	227,423
27	Misc Hydraulic Power Generation Expenses	809,321	553,683
28	Rents	125,257	77,629
29	Maintenance Supervision and Engineering	447,267	6,378
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	65,296	861,316
32	Maintenance of Electric Plant	78,763	27,518
33	Maintenance of Misc Hydraulic Plant	434,240	130,694
34	Total Production Expenses (total 23 thru 33)	4,068,494	2,635,736
35	Expenses per net KWh	0.0507	0.0199

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 2030 Plant Name: Pelton (b)	FERC Licensed Project No. 2030 Plant Name: Pelton (PGE%) (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Outdoor
3	Year Originally Constructed	1957	1957
4	Year Last Unit was Installed	1958	1958
5	Total installed cap (Gen name plate Rating in MW)	110.20	73.47
6	Net Peak Demand on Plant-Megawatts (60 minutes)	110	0
7	Plant Hours Connect to Load	8,742	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	110	0
10	(b) Under the Most Adverse Oper Conditions	60	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	380,662,500	253,775,000
13	Cost of Plant		
14	Land and Land Rights	3,681,440	2,454,416
15	Structures and Improvements	9,376,745	6,258,905
16	Reservoirs, Dams, and Waterways	15,719,776	10,714,549
17	Equipment Costs	23,521,703	15,947,536
18	Roads, Railroads, and Bridges	5,722,162	3,843,153
19	Asset Retirement Costs	51	51
20	TOTAL cost (Total of 14 thru 19)	58,021,877	39,218,610
21	Cost per KW of Installed Capacity (line 20 / 5)	526.5143	533.8044
22	Production Expenses		
23	Operation Supervision and Engineering	242,234	145,677
24	Water for Power	170,036	95,766
25	Hydraulic Expenses	2,627,304	1,852,470
26	Electric Expenses	221,555	133,307
27	Misc Hydraulic Power Generation Expenses	539,669	308,009
28	Rents	10,308	4,467
29	Maintenance Supervision and Engineering	26,925	8,281
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	120,012	62,894
32	Maintenance of Electric Plant	234,504	95,208
33	Maintenance of Misc Hydraulic Plant	105,273	47,087
34	Total Production Expenses (total 23 thru 33)	4,297,820	2,753,166
35	Expenses per net KWh	0.0113	0.0108

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 2195 Plant Name: River Mill (d)	FERC Licensed Project No. 2195 Plant Name: Oak Grove (e)	FERC Licensed Project No. 2233 Plant Name: Sullivan (f)	Line No.
Run-of River	Run-of River	Run-of River	1
Conventional	Conventional	Conventional	2
1911	1924	1895	3
1952	1931	1953	4
20.60	51.00	15.40	5
24	39	18	6
8,072	8,757	8,759	7
			8
25	44	48	9
4	19	7	10
0	5	1	11
70,358,000	156,419,000	132,482,000	12
			13
86,408	9,457	572,077	14
7,516,487	16,216,461	18,320,848	15
59,828,509	25,816,529	32,236,102	16
9,276,483	23,233,863	14,600,098	17
421,796	4,178,800	0	18
64	2,122	2,630	19
77,129,747	69,457,232	65,731,755	20
3,744.1625	1,361.9065	4,268.2958	21
			22
10,109	33,842	11,529	23
43,959	72,464	36,400	24
309,688	1,433,921	151,935	25
35,511	100,740	359,499	26
335,554	532,377	796,512	27
0	542,364	6,577	28
3,805	209,298	3,648	29
0	0	0	30
1,102	4,621	76,832	31
233,108	178,511	176,069	32
44,052	175,498	34,819	33
1,016,888	3,283,636	1,653,820	34
0.0145	0.0210	0.0125	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 2030 Plant Name: Round Butte (d)	FERC Licensed Project No. 2030 Plant Name: Round Butte (PGE%) (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
Storage	Storage		1
Conventional	Conventional		2
1964	1964		3
1964	1964		4
372.50	248.33	0.00	5
305	0	0	6
8,753	0	0	7
			8
345	0	0	9
192	0	0	10
41	0	0	11
872,098,500	581,399,000	0	12
			13
3,726,480	2,521,011	0	14
18,747,784	12,486,681	0	15
170,285,691	111,243,012	0	16
56,100,446	43,682,142	0	17
2,543,433	1,739,032	0	18
165	165	0	19
251,403,999	171,672,043	0	20
674.9101	691.3061	0.0000	21
			22
402,958	284,944	0	23
325,144	234,370	0	24
2,541,613	1,594,594	0	25
366,857	258,999	0	26
984,882	701,742	0	27
28,635	21,496	0	28
97,380	74,593	0	29
0	0	0	30
260,810	191,000	0	31
694,230	523,979	0	32
282,671	211,555	0	33
5,985,180	4,097,272	0	34
0.0069	0.0070	0.0000	35

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

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

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

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

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

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

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

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

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

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Maclaren	1999	0.50	0.4	9	133,799
2	Oregon Military Dept/A.F.R.C	2001	1.60	1.6	82	186,058
3	US Bank Corp Columbia Center	2001	6.89	6.2	867	488,057
4	Portland State University	2004	2.80	2.8	49	261,732
5	Oregon Military Joint Forces HQ	2005	1.60	1.6	64	191,439
6	Stimson Lumber	2005	0.57	0.5	8	159,546
7	Flexential (Formerly ViaWest)	2005	9.00	8.0	1,329	629,142
8	Skyline	2005	2.00	1.8	62	201,526
9	Tri-Quint	2005	0.60	0.5	1	109,968
10	NCCWC- Filter Plant	2005	2.00	1.8	47	122,958
11	PCC Structurals	2005	1.00	0.9	17	113,874
12	Providence Portland Medical Center	2005	6.00	5.4	872	265,383
13	Salem Hospital	2006	8.00	7.2	1,334	269,108
14	Sunrise Water Authority Pump Station	2006	1.25	1.1	17	88,272
15	Providence Newberg Hospital	2006	1.50	1.4	89	156,833
16	vXchnge (Formerly Sungard DSG)	2006	2.00	1.8	47	331,845
17	Kaiser Sunnyside Hospital	2007	4.50	4.1	469	352,752
18	Newberg Waste Water Treatment Plant	2008	2.00	1.8	54	154,458
19	Xerox Corp	2007	4.00	3.6	119	380,259
20	Newberg Water Treatment Plant	2007	1.00	0.9	17	78,159
21	Solar World	2008	3.00	2.7	11	219,984
22	Oregon Dept of Admin Serv - Data Center	2010	2.60	2.3	91	277,254
23	Panasonic (Formerly Sanyo)	2010	1.00	0.9	17	43,144
24	Sysco Foods	2010	2.00	1.8	33	184,779
25	Clackamas Intertie 2	2012	0.60	0.5	10	155,832
26	Dawson Creek	2012	0.80	0.7	13	95,706
27	Kaiser Westside Hospital	2012	4.00	3.6	436	408,830
28	North Plains Pump Station	2012	0.80	0.7	13	53,132
29	Oak Lodge Sanitary District	2012	2.00	1.8	31	229,144
30	Oregon Dept of Admin Serv - Revenue Bldg	2012	1.50	1.4	23	284,255
31	Oregon State Hospital	2012	4.00	3.6	311	172,879
32	Portland Service Center	2012	0.50	0.5	9	322,856
33	Sandy High School	2012	1.25	1.1	19	179,894
34	TATA Communications - Hillsboro	2012	3.56	3.2	160	328,979
35	Tri-City Wastewater Treatment Plant	2012	2.50	2.3	41	161,695
36	TATA Communications - Portland	2013	6.60	5.4	269	612,983
37	City of Hillsboro Crandall Reservoir	2013	0.80	0.7	13	105,854
38	East County Courts	2013	1.50	1.4	51	316,848
39	City of Portland-Columbia Blvd WWTP	2013	1.00	0.9	15	162,234
40	Food Services of America	2013	2.00	1.8	37	229,875
41	Avery DSG	2014	0.80	0.7	13	263,782
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Carver (Readiness Center) DSG	2014	2.00	1.8	116	818,635
2	Juvenile Justice Center	2014	0.75	0.7	26	171,380
3	Clackamas River Water DSG	2014	2.00	1.8	40	383,436
4	Joint Water Commission	2015	5.00	4.5	146	190,302
5	McLane Foodservice	2016	1.50	1.4	24	181,242
6	Flexential Brookwood (Formerly ViaWest Brookwoo)	2016	16.25	11.4	1,902	278,158
7	World Trade Center	2017	3.20	2.9	292	1,021,168
8	Washington County Jail	2017	1.50	1.4	21	325,428
9	OHSU - Vaccine Gene Therapy Institute	2017	1.50	1.4	25	364,108
10	OHSU - Center for Health & Healing	2018	3.00	2.7	3	347,135
11	OHSU - Knight Cancer Research Building	2018	2.00	1.8	12	234,533
12	Solar	2014	6.52	6.5	3,336	2,929,401
13	Total					16,730,033
14						
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GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
267,598			22,819	diesel-low s	1,674	1
116,286		9,912	56,719	diesel-low s	1,936	2
70,856			98,932	diesel-low s	1,674	3
93,476		15,308	34,379	diesel-low s	1,455	4
119,649			34,633	diesel-low s	1,674	5
282,382		2,336	10,774	diesel-low s	1,655	6
69,905		29,952	128,758	diesel-low s	1,781	7
100,763		6,224	4,450	diesel-low s	1,507	8
183,280			12,658	diesel-low s	1,674	9
61,479		6,311	17,351	diesel-low s	1,507	10
113,874		1,488	18,244	diesel-low s	1,544	11
44,231		20,406	51,761	diesel-low s	1,599	12
33,639		44,422	37,858	diesel-low s	1,683	13
70,618				diesel-low s	1,674	14
104,555		5,660	31,552	diesel-low s	1,655	15
165,923		5,711	6,884	diesel-low s	1,694	16
78,389			55,736	diesel-low s	1,674	17
77,229		5,524	29,743	diesel-low s	1,528	18
95,065		6,630	15,795	diesel-low s	1,698	19
78,159		3,312	19,283	diesel-low s	1,583	20
73,328			29,356	diesel-low s	1,674	21
106,636		8,013	23,054	diesel-low s	1,873	22
43,144		1,979	8,477	diesel-low s	1,803	23
92,390		5,075	69,163	diesel-low s	1,628	24
259,720		1,684	6,818	diesel-low s	1,519	25
119,633		3,059	16,357	diesel-low s	1,673	26
102,208		31,496	43,115	diesel-low s	1,535	27
66,415		1,325	11,139	diesel-low s	1,673	28
114,572		4,778	30,405	diesel-low s	1,523	29
189,503		2,802	7,868	diesel-low s	1,798	30
43,220		25,007	47,943	diesel-low s	1,535	31
645,712			9,089	diesel-low s	1,674	32
143,915		3,895	6,899	diesel-low s	1,723	33
92,540			67,404	diesel-low s	1,674	34
64,678		4,540	18,371	diesel-low s	1,526	35
92,876			124,515	diesel-low s	1,674	36
132,318		2,731	5,621	diesel-low s	1,744	37
211,232		6,068	21,388	diesel-low s	1,515	38
162,234		2,346	4,475	diesel-low s	1,760	39
114,938		2,932	15,904	diesel-low s	1,722	40
329,728			13,363	diesel-low s	1,674	41
						42
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GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
409,318		19,633	47,116	diesel-low s	2,656	1
228,507			32,400	diesel-low s	1,674	2
191,718		4,312	28,286	diesel-low s	1,633	3
38,060			13,835	diesel-low s	1,674	4
120,828		2,942	17,738	diesel-low s	1,597	5
17,117		57,985	116,100	diesel-low s	1,595	6
319,115		6,227	51,802	diesel-low s	1,828	7
216,952			5,474	diesel-low s	1,674	8
242,739		2,842	22,434	diesel-low s	1,823	9
115,712			18,116	diesel-low s	1,674	10
117,267			4,010	diesel-low s	1,674	11
449,433	573,975		166,993	solar		12
	573,975	364,867	1,793,357			13
						14
						15
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TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	500KV LINES							
2	GRIZZLY	ROUND BUTTE	500.00	500.00	ST. TOWER	15.54		1
3	GRIZZLY	MALIN	500.00	500.00	ST. TOWER	178.51		1
4	JOHN DAY	GRIZZLY '1'	500.00	500.00				1
5	JOHN DAY	GRIZZLY '2'	500.00	500.00				1
6	MISCELLANEOUS	MISCELLANEOUS	500.00					
7	CARTY	GRASSLAND	500.00	500.00	ST. TOWER	0.78		
8	GRASSLAND	BPA SLATT	500.00	500.00	ST.TOWER	16.73		
9	BOARDMAN	GRASSLAND	500.00	500.00	ST. TOWER	0.90		1
10	COYOTE SPRINGS	BPA SLATT	500.00	500.00				2
11	COLSTRIP PROJECT:							
12	COLSTRIP SWYD.	BROADVIEW 'A'	500.00	500.00	ST. TOWER		112.30	1
13	COLSTRIP SWYD.	BROADVIEW 'B'	500.00	500.00	ST. TOWER		115.80	1
14	BROADVIEW SWYD.	TOWNSEND 'A'	500.00	500.00	ST. TOWER		133.40	1
15	BROADVIEW SWYD.	TOWNSEND 'B'	500.00	500.00	ST. TOWER		133.40	1
16	Colstrip Project Costs	Project Lines						
17	Tot 500KV Line Expenses							
18								
19	BIGLOW CANYON WF	JOHN DAY	230.00	230.00				1
20	TUCANNON WF	CENTRAL FERRY BPA	230.00	230.00	H-WOOD	20.67		1
21								
22	PELTON 230KV PROJECT							
23	PELTON	ROUND BUTTE	230.00	230.00	H-WOOD	8.01		1
24								
25	NON PROJECT 230KV:							
26	BETHEL	ROUND BUTTE	230.00	230.00	H-WOOD	54.87		1
27			230.00	230.00	ST. TOWER	43.83		1
28	ROUND BUTTE	BPA REDMOND	230.00	230.00	H-WOOD	23.83		1
29	ROUND BUTTE	GENERATOR #1	230.00	230.00	ST.TOWER	0.51		1
30	ROUND BUTTE	GENERATOR #2	230.00	230.00	ST.TOWER	0.53		1
31	ROUND BUTTE	GENERATOR #3	230.00	230.00	ST.TOWER	0.53		1
32	BETHEL	BPA TIE (SANTIAM)	230.00	230.00	H-WOOD	3.65		1
33	BETHEL	MONITOR-McLOUGHLIN	230.00	230.00	H-WOOD	35.66		1
34	BEAVER	PORT WESTWARD	230.00	230.00	H-WOOD	0.36		1
35	BIG EDDY BPA	McLOUGHLIN	230.00	230.00	H-WOOD	0.91		1
36					TOTAL	1,015.53	558.95	80

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		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
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	CARVER	GRESHAM	230.00	230.00	H-WOOD	7.39		1
2	CARLTON BPA	SHERWOOD	230.00	230.00	ST. TOWER	8.98	8.87	2
3	McLOUGHLIN	CARVER #1	230.00	230.00	H-WOOD	4.04		1
4			230.00	230.00	ST. MONOP	0.88		1
5	McLOUGHLIN	CARVER #2	230.00	230.00	ST. MONOP	4.88		1
6	BPA KEELER	ST. MARY'S W.	230.00	230.00	H-WOOD	2.87		1
7			230.00	230.00	ST. TOWER	3.80		2
8	BLUE LAKE	TROUTDALE BPA #1	230.00	230.00	ST. MONOP	0.08		1
9			230.00	230.00	ST. MONOP	0.85		2
10			230.00	230.00	ST. TOWER	0.52		2
11	BLUE LAKE	TROUTDALE BPA #2	230.00	230.00	ST. MONOP	0.12		1
12			230.00	230.00	ST. MONOP		0.90	2
13			230.00	230.00	ST. TOWER		0.52	2
14	BLUE LAKE	GRESHAM	230.00	230.00	ST. TOWER	1.05		1
15			230.00	230.00	ST. TOWER	4.88		2
16	PEARL BPA	SHERWOOD	230.00	230.00	ST. MONOP	0.16		1
17			230.00	230.00	ST. TOWER		4.19	1
18			230.00	230.00	H- WOOD		0.59	1
19	GRESHAM	LINNEMAN	230.00	230.00	ST. TOWER	0.27		1
20	McLOUGHLIN	PEARL(BPA) -SHERWOOD	230.00	230.00	ST. TOWER	4.62		1
21			230.00	230.00	ST. TOWER	11.68		2
22			230.00	230.00	ST. MONOP	0.27		1
23	ST. MARY'S W.	MURRAYHILL	230.00	230.00	ST. TOWER	3.07		1
24			230.00	230.00	ST. TOWER	2.15		2
25	HORIZON	KEELER BPA	230.00	230.00	ST. MONOP	0.79		1
26			230.00	230.00	ST. MONOP	0.68		2
27	KEELER BPA	RIVERGATE	230.00	230.00	ST. TOWER	0.09		2
28	RIVERGATE	ROSS BPA	230.00	230.00	ST. TOWER	0.10		2
29	MURRAYHILL	SHERWOOD #1	230.00	230.00	ST. TOWER	0.02	5.59	2
30	MURRAYHILL	SHERWOOD #2	230.00	230.00	ST. TOWER	5.59		2
31	PORT WESTWARD	TROJAN #1	230.00	230.00	H-WOOD	8.46		1
32			230.00	230.00	ST. MONOP	10.33		2
33	PORT WESTWARD	TROJAN #2	230.00	230.00	ST. MONOP	8.43		1
34			230.00	230.00	ST. MONOP		10.35	2
35	HORIZON	ST. MARYS-TROJAN	230.00	230.00	ST. TOWER	41.26		1
36					TOTAL	1,015.53	558.95	80

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1			230.00	230.00	ST. MONOP	4.10		1
2	TROJAN	RIVERGATE	230.00	230.00	ST. TOWER	2.57	32.61	2
3								
4	Tot Nonproj 230kv Costs							
5								
6	GRESHAM	TROUTDALE PACW	230.00	230.00	H-WOOD	0.43	0.43	1
7	BOARDMAN	PPL DALREED	230.00	230.00	H-WOOD	16.75		1
8								
9	Tot 230KV LINE EXPENSES							
10								
11	ALL 115KV LINES					435.74		
12	ALL 57KV LINES					11.81		
13								
14								
15								
16								
17								
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19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	1,015.53	558.95	80

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
1780MCMACSR	50,953	1,645,820	1,696,773					2
1780MCMACSR	275,427	17,485,375	17,760,802					3
		148,889	148,889					4
		148,889	148,889					5
	5,904		5,904					6
1780MCMACSR		10,214,468	10,214,468					7
1780MCMACSR								8
1780MCMACSR		6,353,549	6,353,549					9
		3,624,934	3,624,934					10
								11
								12
								13
								14
								15
	1,194,326	43,101,062	44,295,388					16
				1,329,612	596,675	3,128,552	5,054,839	17
								18
		3,040,852	3,040,852					19
954ACSR		1,956,263	1,956,263					20
								21
								22
795MCMACSR	7,579	401,225	408,804					23
								24
								25
1272MCMACSR								26
1272MCMACSR								27
795MCMACSR								28
795MCMACSR								29
795MCMACSR								30
795MCMACSR								31
795MCMACSR								32
1272AAC								33
1272MCMACSR								34
1272MCMACSR								35
	10,483,008	301,913,189	312,396,197	3,725,387	1,699,263	3,574,527	8,999,177	36

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272MCMAAC								1
1272MCMAAC								2
1272MCMAAC								3
1272MCMAAC								4
1272MCMACSS								5
1590MCMACSRTW								6
1590MCMACSRTW								7
1780MCMACSR								8
1780MCMACSR								9
1780MCMACSR								10
1272MCMACSS								11
1272MCMACSS								12
1272MCMACSS								13
1272MCMACSS								14
1272MCMACSS								15
2388MCMAACTW								16
2388MCMAACTW								17
2388MCMAACTW								18
1272MCMAAC								19
1272MCMAAC								20
1780MCMACSR								21
1780MCMACSR								22
1272MCMAAC								23
1272MCMAAC								24
1272MCMACSS								25
1272MCMACSS								26
1272AAC								27
1272AAC								28
1272MCMAAC								29
1272MCMAAC								30
2156MCMACSS								31
2156MCMACSS								32
2156MCMACSS								33
2156MCMACSS								34
1272MCMACSS								35
	10,483,008	301,913,189	312,396,197	3,725,387	1,699,263	3,574,527	8,999,177	36

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1272MCMACSS								1
1272MCMACSR								2
								3
	8,567,433	111,564,533	120,131,966	2,395,775	1,102,588	445,975	3,944,338	4
								5
954KCMACSR								6
795KCMAAC		976,079	976,079					7
								8
								9
								10
	381,386	100,262,212	100,643,598					11
		989,039	989,039					12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
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								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	10,483,008	301,913,189	312,396,197	3,725,387	1,699,263	3,574,527	8,999,177	36

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Schedule Page: 422 Line No.: 4 Column: a

Portland General Electric made payment in the form of Contribution in Aid of Construction (CIAC) in 2011 to Bonneville Power Administration (BPA) in support of increased line capacity as part of the 500-KV California Oregon Intertie. BPA installed higher capacity conductor on this line. PGE has certain capacity responsibilities in conjunction with the 500-KV California Oregon Intertie. PGE recorded the CIAC to FERC account 356 Transmission Overhead Conductors and Devices. Wire mileage not reported as BPA is owner/operator of this section of Transmission Line.

Schedule Page: 422 Line No.: 5 Column: a

Portland General Electric made payment in the form of Contribution in Aid of Construction (CIAC) in 2011 to Bonneville Power Administration (BPA) in support of increased line capacity as part of the 500-KV California Oregon Intertie. BPA installed higher capacity conductor on this line. PGE has certain capacity responsibilities in conjunction with the 500-KV California Oregon Intertie. PGE recorded the CIAC to FERC account 356 Transmission Overhead Conductors and Devices. Wire Mileage is not reported here as BPA is owner/operator of this portion of the Transmission Line.

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

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

Schedule Page: 422 Line No.: 10 Column: a

Portland General Electric made payment in the form of Contribution in Aid of Construction (CIAC) in 1995 to Bonneville Power Administration. PGE recorded these costs to FERC accounts 354 Transmission Towers and Fixtures, 356 Transmission Overhead Conductors and Devices. Wire Mileage is not reported here as BPA is owner/operator of these Transmission Lines.

Schedule Page: 422 Line No.: 11 Column: a

Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. Total length is indicated. Costs are respondent's share.

Schedule Page: 422 Line No.: 19 Column: a

Portland General Electric made payment in the form of Contribution in Aid of Construction (CIAC) in 2007 to Bonneville Power Administration. PGE recorded the CIAC to FERC accounts 355 Transmission Poles and Fixtures, 356 Transmission Overhead Conductors and Devices. Wire mileage is not reported here as BPA is owner/operator of these transmission lines.

Schedule Page: 422 Line No.: 23 Column: a

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Total length is indicated. Costs are respondent's share.

Schedule Page: 422 Line No.: 35 Column: a

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

Schedule Page: 422.1 Line No.: 2 Column: a

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

Schedule Page: 422.1 Line No.: 16 Column: a

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

Schedule Page: 422.1 Line No.: 27 Column: a

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

Schedule Page: 422.1 Line No.: 28 Column: a

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

Schedule Page: 422.2 Line No.: 6 Column: a

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

Schedule Page: 422.2 Line No.: 7 Column: a

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

Schedule Page: 422.2 Line No.: 11 Column: a

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2019/Q4

FOOTNOTE DATA

On September 6, 2019, PGE filed a petition for declaratory order in Docket No. EL19-95-00 seeking to reclassify certain 57 kV and 115 kV facilities from distribution to transmission. The case was held in abeyance, pending the outcome of a parallel proceeding before the OPUC.

On November 22, 2019, PGE filed a motion to supplement the petition to include the OPUC's decision in Docket No. UM 2031, which granted reclassification of a subset of the facilities. The stipulation in OPUC Order No. 19-400 identified four characteristics that reflect the reclassification:

A. Radial lines both to distribution and to customers tend to be distribution, but radial generation tie facilities tend to be transmission for accounting purposes but should be classified as production for ratemaking purposes;

B. Non-radial line segments of 100 kV or higher voltage tend to be transmission;

C. Transformers with a secondary voltage under 100 kV tend to be distribution; and

D. Substation assets (e.g. circuit breakers) that are part of the path that connect the transmission line segments, or equipment associated with transformers with a secondary voltage higher than 100 kV, are considered transmission

The FERC approved the reclassification of identified facilities on December 31, 2019. As a result, PGE reclassified certain 115 kV facilities totaling $101,632,637 from distribution to transmission.

Schedule Page: 422.2 Line No.: 12 Column: a

On September 6, 2019, PGE filed a petition for declaratory order in Docket No. EL19-95-00 seeking to reclassify certain 57 kV and 115 kV facilities from distribution to transmission. The case was held in abeyance, pending the outcome of a parallel proceeding before the OPUC.

On November 22, 2019, PGE filed a motion to supplement the petition to include the OPUC's decision in Docket No. UM 2031, which granted reclassification of a subset of the facilities. The stipulation in OPUC Order No. 19-400 identified four characteristics that reflect the reclassification:

E. Radial lines both to distribution and to customers tend to be distribution, but radial generation tie facilities tend to be transmission for accounting purposes but should be classified as production for ratemaking purposes;

F. Non-radial line segments of 100 kV or higher voltage tend to be transmission;

G. Transformers with a secondary voltage under 100 kV tend to be distribution; and

H. Substation assets (e.g. circuit breakers) that are part of the path that connect the transmission line segments, or equipment associated with transformers with a secondary voltage higher than 100 kV, are considered transmission

The FERC approved the reclassification of identified facilities on December 31, 2019. As a result, PGE reclassified certain 115 kV facilities totaling $101,632,637 from distribution to transmission.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

TRANSMISSION LINES ADDED DURING YEAR

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

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	HORIZON	ST.MARYS-TROJAN	12.56	ST.TOWER		1	1
2	2019 Reclass	2019 Reclass	447.55				
3							
4							
5							
6							
7							
8							
9							
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11							
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35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		460.11			1	1

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
1272	ACSS		230			12,979,329		12,979,329	1
0			115	358,561	36,968,242	60,772,988		98,099,791	2
									3
									4
									5
									6
									7
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									43
				358,561	36,968,242	73,752,317		111,079,120	44

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Schedule Page: 424 Line No.: 2 Column: a

On September 6, 2019, PGE filed a petition for declaratory order in Docket No. EL19-95-00 seeking to reclassify certain 57 kV and 115 kV facilities from distribution to transmission. The case was held in abeyance, pending the outcome of a parallel proceeding before the OPUC.

On November 22, 2019, PGE filed a motion to supplement the petition to include the OPUC's decision in Docket No. UM 2031, which granted reclassification of a subset of the facilities. The stipulation in OPUC Order No. 19-400 identified four characteristics that reflect the reclassification:

A. Radial lines both to distribution and to customers tend to be distribution, but radial generation tie facilities tend to be transmission for accounting purposes but should be classified as production for ratemaking purposes;

B. Non-radial line segments of 100 kV or higher voltage tend to be transmission;

C. Transformers with a secondary voltage under 100 kV tend to be distribution; and

D. Substation assets (e.g. circuit breakers) that are part of the path that connect the transmission line segments, or equipment associated with transformers with a secondary voltage higher than 100 kV, are considered transmission

The FERC approved the reclassification of identified facilities on December 31, 2019. As a result, PGE reclassified certain 115 kV transmission line facilities totaling $98,099,791 from distribution to transmission.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	9 Substation < 10 MVa capacity at various locat, OR	Distrib./unattended			
2	Abernethy, Oregon City, OR	Distrib./unattended	115.00	13.00	
3	Amity, near Amity, OR	Distrib./unattended	57.00	13.00	
4	Arleta, Portland, OR	Distrib./unattended	57.00	13.00	
5	Banks, Banks, Or	Distrib./unattended	57.00	13.00	
6	Barnes, Salem, OR	Distrib./unattended	115.00	13.00	
7	Boring, near Boring, OR	Distrib./unattended	57.00	13.00	
8	Brookwood, near Hillsboro, OR	Distrib./unattended	57.00	13.00	
9	Canby, near Barlow, OR	Distrib./unattended	57.00	13.00	
10	Cedar Hills, near Beaverton, OR	Distrib./unattended	115.00	13.00	
11	Centennial, near Gresham, OR	Distrib./unattended	115.00	13.00	
12	Chemawa BPA, near Salem, OR	Distrib./unattended	115.00		
13	Chemawa BPA, near Salem, OR	Distrib./unattended	57.00		
14	Claxtar, Salem, OR	Distrib./unattended	57.00	13.00	
15	Coffee Creek, Sherwood, OR	Distrib./unattended	115.00	13.00	
16	Cornell, Portland, OR	Distrib./unattended	115.00	13.00	
17	Dilley, near Forest Grove, OR	Distrib./unattended	57.00	13.00	
18	Durham, Tigard, OR	Distrib./unattended	115.00	13.00	
19	Eagle Creek, Eagle Creek, OR	Distrib./unattended	57.00	13.00	
20	Elma, near Salem, OR	Distrib./unattended	57.00	13.00	
21	Estacada, Estacada, OR	Distrib./unattended	57.00	13.00	
22	Garden Home, near Portland, OR	Distrib./unattended	115.00	13.00	
23	Glencoe, Portland, OR	Distrib./unattended	115.00	13.00	
24	Harmony, near Milwaukie, OR	Distrib./unattended	115.00	13.00	
25	Hayden Island, near Portland, OR	Distrib./unattended	115.00	13.00	
26	Hemlock, Portland, OR	Distrib./unattended	115.00	13.00	
27	Hillsboro, Hillsboro, OR	Distrib./unattended	57.00	13.00	
28	Hogan North, Gresham, OR	Distrib./unattended	115.00	13.00	
29	Holgate, Portland, OR	Distrib./unattended	57.00	13.00	
30	Huber, near Beaverton, OR	Distrib./unattended	115.00	13.00	
31	Jennings Lodge, Jennings Lodge, OR	Distrib./unattended	115.00	13.00	
32	Kelley Point, Portland, OR	Distrib./unattended	115.00	13.00	
33	Leland, Oregon City, OR	Distrib./unattended	57.00	13.00	
34	Lents, near Portland, OR	Distrib./unattended	115.00	13.00	
35	Lents, near Portland, OR	Distrib./unattended	57.00	11.00	
36	Main, Hillsboro, OR	Distrib./unattended	57.00	13.00	
37	McClain, Salem, OR	Distrib./unattended	57.00	13.00	
38	Middle Grove, near Middle Grove, OR	Distrib./unattended	115.00	13.00	
39	Midway, near Portland, OR	Distrib./unattended	115.00	13.00	
40	Mobile sub No. 1, OR	Distrib./unattended	115.00	57.00	13.00

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Mobile sub No. 2, OR	Distrib./unattended	115.00	57.00	13.00
2	Mobile Sub No. 3, OR	Distrib./unattended	115.00	57.00	13.00
3	Mobile Sub No. 4, OR	Distrib./unattended	115.00	57.00	13.00
4	Mobile Sub No. 5, OR	Distrib./unattended	115.00	57.00	13.00
5	Mobile Sub No. 6, OR	Distrib./unattended	115.00	57.00	13.00
6	Mobile Sub No. 7, OR	Distrib./unattended	115.00	57.00	13.00
7	Mobile Sub No. 8, OR	Distrib./unattended	115.00	57.00	13.00
8	Molalla, Molalla, OR	Distrib./unattended	57.00	13.00	
9	Mt. Angel, Mt. Angel, OR	Distrib./unattended	57.00	13.00	
10	Mt. Pleasant, Oregon City, OR	Distrib./unattended	115.00	13.00	
11	Multnomah, Portland, OR	Distrib./unattended	115.00	13.00	
12	North Marion, near Woodburn, OR	Distrib./unattended	57.00	13.00	
13	North Plains, North Plains, OR	Distrib./unattended	57.00	13.00	
14	Northern, Portland, OR	Distrib./unattended	57.00	11.00	
15	Oak Hills, near Beaverton, OR	Distrib./unattended	115.00	13.00	
16	Oregon City - BPA, near Wilsonville, OR	Distrib./unattended	57.00		
17	Orient, near Gresham, OR	Distrib./unattended	57.00	13.00	
18	Peninsula Park, Portland, OR	Distrib./unattended	115.00	13.00	
19	Raleigh Hills, near Portland, OR	Distrib./unattended	115.00	13.00	
20	Ramapo, near Portland, OR	Distrib./unattended	115.00	13.00	
21	Redland, near Oregon City, OR	Distrib./unattended	115.00	13.00	
22	Rhododendron Switching, OR	Distrib./unattended	57.00		
23	Riverview, Portland, OR	Distrib./unattended	115.00	13.00	
24	Rockwood, near Gresham, OR	Distrib./unattended	115.00	13.00	
25	Roseway, Hillsboro, OR	Distrib./unattended	115.00	13.00	
26	Salem-PGE, near Salem, OR	Distrib./unattended	57.00	13.00	
27	Sandy, Sandy, OR	Distrib./unattended	57.00	13.00	
28	Scoggins, near Gaston, OR	Distrib./unattended	57.00	13.00	
29	Sheridan, Sheridan, OR	Distrib./unattended	57.00	13.00	
30	Silverton, Silverton, OR	Distrib./unattended	57.00	13.00	
31	Springdale, near Springdale, OR	Distrib./unattended		12.50	
32	St. Johns-BPA, near Portland, OR	Distrib./unattended		11.00	
33	St. Louis, Gevais, OR	Distrib./unattended	57.00	13.00	
34	Stephens, Portland, OR	Distrib./unattended	57.00	11.00	
35	Summit, Government Camp, OR	Distrib./unattended	57.00	13.00	
36	Summit, Government Camp, OR	Distrib./unattended	24.00	13.00	
37	Swan Island, Portland, OR	Distrib./unattended	115.00	13.00	
38	Sylvan, near Portland, OR	Distrib./unattended	115.00	13.00	
39	Tigard, Tigard, OR	Distrib./unattended	115.00	13.00	
40	Twilight, Canby, OR	Distrib./unattended	57.00	13.00	

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Waconda, near Hopmere, OR	Distrib./unattended	57.00	13.00	
2	Wallace, Salem, OR	Distrib./unattended	57.00	13.00	
3	Welches, near Welches, OR	Distrib./unattended	57.00	24.00	
4	Welches, near Welches, OR	Distrib./unattended	57.00	13.00	
5	Willamina, near Willamina, OR	Distrib./unattended	57.00	13.00	
6	Willbridge, Portland, OR	Distrib./unattended	115.00	11.00	
7	Woodburn, Woodburn, OR	Distrib./unattended	57.00	13.00	
8	Yamhill, near Yamhill, OR	Distrib./unattended	57.00	13.00	
9					
10					
11	Alder, Portland, OR	T&D/unattended	115.00	13.00	
12	Beaverton, Beaverton, OR	T&D/unattended	115.00	13.00	
13	Bell, near Portland, OR	T&D/unattended	115.00	13.00	
14	Bethany, Portland, OR	T&D/unattended	115.00	13.00	
15	Bethel, Salem, OR	T&D/unattended	230.00	115.00	13.00
16	Bethel, Salem, OR	T&D/unattended	115.00	57.00	13.00
17	Bethel, Salem ,OR	T&D/unattended	115.00	13.00	
18	Blue Lake, Troutdale, OR	T&D/unattended	230.00	115.00	13.00
19	Blue Lake, Troutdale, OR	T&D/unattended	115.00	13.00	
20	Boones Ferry, Lake Oswego, OR	T&D/unattended	115.00	13.00	
21	Canemah, Oregon City, OR	T&D/unattended	115.00	57.00	13.00
22	Canyon, Portland, OR	T&D/unattended	115.00	13.00	
23	Carver, Carver, OR	T&D/unattended	230.00	115.00	13.00
24	Carver, Carver, OR	T&D/unattended	115.00	13.00	
25	Clackamas, Clackamas, OR	T&D/unattended	115.00	13.00	
26	Cornelius, Cornelius, OR	T&D/unattended	115.00	57.00	13.00
27	Cornelius, Cornelius, OR	T&D/unattended	57.00	13.00	
28	Culver, Salem, OR	T&D/unattended	115.00	13.00	
29	Curtis, Portland, OR	T&D/unattended	115.00	13.00	
30	Dayton, near Dayton, OR	T&D/unattended	115.00	57.00	13.00
31	Dayton, near Dayton, OR	T&D/unattended	57.00	13.00	
32	Delaware, Portland, OR	T&D/unattended	115.00	13.00	
33	Denny, Beaverton, OR	T&D/unattended	115.00	13.00	
34	Dunn's Corner, near Sandy, OR	T&D/unattended	57.00	13.00	
35	E., Portland, OR	T&D/unattended	115.00	13.00	
36	E., Portland, OR	T&D/unattended	115.00	11.00	
37	Eastport, Portland, OR	T&D/unattended	115.00	13.00	
38	Fairmount, Salem, OR	T&D/unattended	115.00	13.00	
39	Fairview, Fairview OR	T&D/unattended	115.00	13.00	
40	Faraday Plant, near Estacada, OR	T&D/unattended	115.00	13.00	

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Faraday, Switchyard, OR	T&D/unattended	115.00	57.00	13.00
2	Faraday, Switchyard, OR	T&D/unattended	57.00	11.00	
3	Glencullen, Portland, OR	T&D/unattended	115.00	13.00	
4	Glendoveer, near Portland, OR	T&D/unattended	115.00	13.00	
5	Glisan, Gresham, OR	T&D/unattended	115.00	13.00	
6	Grand Ronde, Grand Ronde, OR	T&D/unattended	115.00	57.00	13.00
7	Grand Ronde, Grand Ronde, OR	T&D/unattended	115.00	13.00	
8	Harborton, near Portland, OR	T&D/unattended	115.00	13.00	
9	Harrison Sub, Portland, OR	T&D/unattended	115.00	13.00	
10	Hillcrest, Salem, OR	T&D/unattended	115.00	13.00	
11	Hogan South, Gresham, OR	T&D/unattended	115.00	57.00	13.00
12	Hogan South, Gresham, OR	T&D/unattended	115.00	13.00	
13	Indian, near Salem, OR	T&D/unattended	115.00	13.00	
14	Island, near Milwaukie, OR	T&D/unattended	115.00	13.00	
15	Kelly Butte, Portland, OR	T&D/unattended	115.00	13.00	
16	King City, King City, OR	T&D/unattended	115.00	13.00	
17	Liberty, Salem, OR	T&D/unattended	115.00	13.00	
18	Market, Salem, OR	T&D/unattended	115.00	13.00	
19	Marquam, Portland, OR	T&D/unattended	115.00	13.00	
20	McGill, Gresham, OR	T&D/unattended	115.00	13.00	
21	McLoughlin, near Oregon City, OR	T&D/unattended	230.00	115.00	13.00
22	Meridian, near Tualatin, OR	T&D/unattended	115.00	13.00	
23	Mill Creek, near Salem, OR	T&D/unattended	115.00	13.00	
24	Monitor, near Monitor, OR	T&D/unattended	230.00	57.00	13.00
25	Murrayhill, Beaverton, OR	T&D/unattended	115.00	13.00	
26	Murrayhill, Beaverton, OR	T&D/unattended	230.00	115.00	13.00
27	Newberg, Newberg, OR	T&D/unattended	115.00	13.00	
28	Oak Grove, Three Lynx, OR	T&D/unattended	115.00	13.00	
29	Oak Grove, Three Lynx, OR	T&D/unattended	115.00	11.00	
30	Oak Grove, Three Lynx, OR	T&D/unattended	13.00	11.00	
31	Oak Grove, Three Lynx, OR	T&D/unattended	13.00	0.48	
32	Orenco, near Hillsboro, OR	T&D/unattended	115.00	57.00	13.00
33	Orenco, near Hillsboro, OR	T&D/unattended	115.00	13.00	
34	Oswego, Lake Oswego, OR	T&D/unattended	115.00	13.00	
35	Oxford, Salem, OR	T&D/unattended	115.00	13.00	
36	Pleasant Valley, near Portland, OR	T&D/unattended	115.00	13.00	
37	Portsmouth, Portland, OR	T&D/unattended	115.00	13.00	
38	Progress, near Tigard, OR	T&D/unattended	115.00	13.00	
39	Reedville, near Beaverton, OR	T&D/unattended	115.00	13.00	
40	River Mill, near Beaverton, OR	T&D/unattended	57.00	11.00	

SUBSTATIONS

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3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Rivergate North Yard, Portland, OR	T&D/unattended	230.00	115.00	13.00
2	Rivergate South Yard, Portland, OR	T&D/unattended	115.00	13.00	
3	Rivergate South Yard, Portland, OR	T&D/unattended	115.00	11.00	
4	Rosemont, near Lake Oswego, OR	T&D/unattended	115.00	13.00	
5	Round Butte, near Madras, OR	T&D/unattended	500.00	230.00	12.00
6	Round Butte, near Madras, OR	T&D/unattended	230.00	13.00	
7	Ruby, Gresham, OR	T&D/unattended	115.00	13.00	
8	Scappose, Scappose, OR	T&D/unattended	115.00		
9	Scholls Ferry, Beaverton, OR	T&D/unattended	115.00	13.00	
10	Sellwood, Portland, OR	T&D/unattended	115.00	57.00	13.00
11	Sellwood, Portland, OR	T&D/unattended	115.00	13.00	
12	Shute, Hillsboro, OR	T&D/unattended	115.00	34.50	
13	Six Corners, Six Corners, OR	T&D/unattended	115.00	13.00	
14	Springbrook, Newberg, OR	T&D/unattended	115.00	13.00	
15	St. Helens, near St. Helens, OR	T&D/unattended	115.00		
16	St. Marys, West Yard, Beaverton, OR	T&D/unattended	230.00	115.00	13.00
17	St. Marys, East Yard, Beaverton, OR	T&D/unattended	115.00	13.00	
18	Sullivan, West Linn, OR	T&D/unattended	115.00	13.00	
19	Sullivan, West Linn, OR	T&D/unattended	57.00	4.15	
20	Sunset, near Hillsboro, OR	T&D/unattended	115.00	13.00	
21	Sunset, near Hillsboro, OR	T&D/unattended	115.00	34.50	
22	Tabor, Portland, OR	T&D/unattended	115.00	13.00	
23	Tabor, Portland, OR	T&D/unattended	57.00		
24	Tektronix, Beaverton, OR	T&D/unattended	115.00	13.00	
25	Town Center, Portland, OR	T&D/unattended	115.00	13.00	
26	Trojan, near Rainier, OR	T&D/unattended	230.00	13.00	
27	Tualatin, Tualatin, OR	T&D/unattended	115.00	13.00	
28	University, Salem, OR	T&D/unattended	115.00	13.00	
29	Urban, Portland, OR	T&D/unattended	115.00	13.00	
30	West Portland, Lower Yard, Tigard, OR	T&D/unattended	115.00		
31	West Portland, Upper Yard, Tigard, OR	T&D/unattended	115.00	13.00	
32	West Union, near Hillsboro, OR	T&D/unattended	115.00	13.00	
33	Willsonville, near Willsonville ,OR	T&D/unattended	115.00	13.00	
34					
35					
36	Bakeoven, BPA, near Bakeoven, OR	Transm./unattended	500.00		
37	Beaver Plant, near Clatskanie, OR	Transm./unattended	230.00	13.00	
38	Beaver Plant, near Clatskanie, OR	Transm./unattended	230.00	24.00	
39	Biglow Canyon Wind Farm, Wasco, OR	Transm./unattended	230.00	34.50	13.00
40	Boardman, near Boardman, OR	Transm./unattended	500.00	24.00	

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Boardman, OR	Transm./unattended	230.00	7.20	
2	Boardman, OR	Transm./unattended	24.00	7.20	
3	Broadview Subst. near Broadview, MT	Transm./unattended	500.00	230.00	
4	Buckley, BPA near Buckley, WA	Transm./unattended	500.00		
5	Captain Jack, BPA, near Malin, OR	Transm./unattended	500.00		
6	Carty, near Boardman, OR	Transm./unattended	500.00	21.00	
7	Carty, near Boardman, OR	Transm./unattended	16.00	7.20	4.20
8	Colstrip Plant, near Colstrip, MT	Transm./unattended	500.00	26.00	
9	Colstrip Subst. near Colstrip, MT	Transm./unattended	500.00	230.00	
10	Coyote Springs, Boardman, OR	Transm./unattended	500.00		
11	Forest Grove, Forest Grove, OR	Transm./unattended	115.00		
12	Fort Rock, approx 12 mi NE of Silver Lake, OR	Transm./unattended	500.00		
13	Grassland, near Boardman, OR	Transm./unattended	500.00		
14	Gresham, near Gresham, OR	Transm./unattended	230.00	115.00	13.00
15	Grizzly, BPA, near Madras, OR	Transm./unattended	500.00		
16	Horizon, Hillsboro, OR	Transm./unattended	230.00	115.00	13.00
17	Keeler, BPA, Hillsboro, OR				
18	Linneman, near Gresham, OR	Transm./unattended	230.00	115.00	13.00
19	Malin, BPA, near Malin, OR	Transm./unattended	500.00		
20	North Fork, near Estacada, OR	Transm./unattended	115.00	13.00	0.48
21	Pearl, BPA, near Wilsonville, OR	Transm./unattended	230.00		
22	Pelton, near Madras, OR	Transm./unattended	230.00	13.00	
23	Pelton, near Madras, OR	Transm./unattended	13.00	13.00	
24	Port Westward, near Clatskanie, OR	Transm./unattended	230.00	18.00	
25	Port Westward, near Clatskanie, OR	Transm./unattended	13.00	4.20	
26	Sand Springs, 22 mi E/22 mi S of Bend, OR	Transm./unattended	500.00		
27	Sherwood, near Six Corners, OR	Transm./unattended	230.00	115.00	13.00
28	Slatt, BPA, Arlington, OR	Transm./unattended	500.00		
29	Sycan, 27 mi S of Silver Lake, OR	Transm./unattended	500.00		
30	Troutdale, BPA near Troutdale OR	Transm./unattended	230.00		
31	Tucannon Mullan Switchyard, Dayton, WA	Transm./unattended	230.00	34.50	13.00
32	TOTAL MVa		31304.00	5278.93	419.68
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
69	9		Capacitor Banks	3	15,600	1
45	2		Capacitor Banks	4	12,000	2
15	2					3
42	2		Capacitor Banks	2	7,200	4
20	1		Capacitor Banks	2	3,000	5
42	2		Capacitor Banks	2	6,000	6
24	2		Capacitor Banks	1	12,150	7
28	1		Capacitor Banks	2	6,000	8
39	4					9
56	2		Capacitor Banks	4	13,200	10
56	2		Capacitor Banks	4	12,000	11
						12
						13
28	1		Capacitor Banks	2	6,000	14
28	1		Capacitor Banks	2	6,000	15
28	1		Capacitor Banks	2	6,000	16
13	1		Capacitor Banks	3	9,000	17
56	2		Capacitor Banks	4	12,600	18
14	1					19
56	2		Capacitor Banks	4	12,000	20
30	2		Capacitor Banks	2	3,600	21
28	1					22
25	1		Capacitor Banks	2	6,000	23
50	2		Capacitor Banks	4	12,000	24
34	2		Capacitor Banks	4	12,000	25
28	1		Capacitor Banks	2	6,000	26
43	2		Capacitor Banks	4	14,400	27
56	2		Capacitor Banks	4	12,000	28
39	2		Capacitor Banks	2	7,200	29
56	2		Capacitor Banks	2	6,000	30
53	2					31
56	2		Capacitor Banks	4	12,000	32
28	1		Capacitor Banks	2	6,000	33
22	1					34
20	2					35
84	3		Capacitor Banks	6	20,400	36
23	3					37
53	2		Capacitor Banks	4	12,000	38
34	2		Capacitor Banks	1	3,600	39
15	1					40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
34	1					1
29	1					2
34	1					3
34	1					4
34	1					5
25	1					6
25	1					7
42	2		Capacitor Banks	4	9,000	8
20	1		Capacitor Banks	3	15,000	9
45	2		Capacitor Banks			10
39	2		Capacitor Banks	3	9,600	11
31	3		Capacitor Banks	3	15,000	12
20	1		Capacitor Banks	4	18,000	13
28	2					14
56	2		Capacitor Banks	4	14,400	15
						16
28	1		Capacitor Banks	2	6,000	17
28	1		Capacitor Banks	2	6,000	18
28	1		Capacitor Banks	2	6,600	19
28	1		Capacitor Banks	2	6,000	20
22	1					21
						22
28	1		Capacitor Banks	2	6,000	23
78	3		Capacitor Banks	5	15,000	24
28	1	1	Capacitor Banks	2	6,000	25
45	2		Capacitor Banks	4	12,000	26
28	1		Capacitor Banks	2	6,000	27
13	2		Capacitor Banks	1	10,800	28
17	1		Capacitor Banks	3	15,600	29
42	2					30
						31
						32
24	2		Capacitor Banks	2	7,200	33
100	2		Capacitor Banks	2	16,800	34
8	1					35
14	1					36
53	2		Capacitor Banks	4	12,000	37
22	1		Capacitor Banks	2	6,000	38
45	2		Capacitor Banks	4	12,000	39
28	1	1	Capacitor Banks	3	19,200	40

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
41	2		Capacitor Banks	2	6,000	1
28	1	1	Capacitor Banks	2	6,000	2
10	1		Capacitor Banks	1	12,000	3
18	2		Capacitor Banks	2	6,000	4
31	2		Capacitor Banks	2	7,800	5
20	1					6
42	2		Capacitor Banks	4	13,200	7
15	2		Capacitor Banks	1	1,800	8
						9
						10
56	2		Capacitor Banks	2	6,000	11
34	2		Capacitor Banks	4	12,000	12
66	3		Capacitor Banks	4	12,000	13
56	2		Capacitor Banks	5	15,000	14
564	2					15
140	1					16
28	1		Capacitor Banks	2	6,000	17
640	2					18
56	2		Capacitor Banks	2	6,000	19
50	2		Capacitor Banks	2	7,200	20
250	6					21
200	4		Capacitor Banks	8	28,800	22
640	2					23
56	2		Capacitor Banks	4	12,000	24
41	2		Capacitor Banks	4	13,200	25
140	1					26
28	1		Capacitor Banks	2	6,000	27
28	1					28
17	1		Capacitor Banks	2	6,000	29
125	1					30
20	2		Capacitor Banks	4	6,000	31
28	1					32
56	2		Capacitor Banks	2	6,000	33
14	1		Capacitor Banks	2	3,000	34
208	5		Capacitor Banks	4	28,800	35
132	4		Capacitor Banks	2	32,400	36
17	1					37
25	1		Capacitor Banks	1	3,600	38
50	2		Capacitor Banks	1	3,000	39
27	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
140	1					1
32	2					2
24	1		Capacitor Banks	2	6,000	3
50	2		Capacitor Banks	4	12,000	4
45	2		Capacitor Banks	4	12,000	5
33	1	1				6
13	1		Capacitor Banks	2	3,000	7
25	1	1	Capacitor Banks	6	19,200	8
28	1		Capacitor Banks	2	6,000	9
28	1		Capacitor Banks	2	6,000	10
125	3					11
56	2		Capacitor Banks	4	12,000	12
56	2		Capacitor Banks	3	10,800	13
45	2		Capacitor Banks	4	12,000	14
45	2		Capacitor Banks	2	6,000	15
56	2		Capacitor Banks	4	12,000	16
50	2		Capacitor Banks	3	10,200	17
28	1		Capacitor Banks	2	6,000	18
250	5		Capacitor Banks	10	54,000	19
75	3		Capacitor Banks	6	18,000	20
640	2					21
84	3		Capacitor Banks	6	18,600	22
17	1		Capacitor Banks	2	6,000	23
125	1					24
56	2		Capacitor Banks	3	10,800	25
320	1					26
45	2		Capacitor Banks	4	12,000	27
8	1					28
64	2					29
						30
						31
280	2	1	Capacitor Banks	6	18,000	32
81	3					33
34	2		Capacitor Banks	2	7,200	34
50	2		Capacitor Banks	4	12,300	35
56	2		Capacitor Banks	4	12,000	36
28	1					37
50	2		Capacitor Banks	4	13,800	38
84	3		Capacitor Banks	6	18,000	39
32	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
520	4	1	Capacitor Banks	1	24,000	1
22	1		Capacitor Banks	2	7,200	2
22	1		Capacitor Banks	2	6,716	3
28	1		Capacitor Banks	2	6,000	4
561	3		Reactors	12	180,000	5
394	4	2				6
28	1		Capacitor Banks	2	6,000	7
						8
28	1		Capacitor Banks	2	6,000	9
140	1		Capacitor Banks	1	24,000	10
28	1		Capacitor Banks	2	6,000	11
100	2	1	Capacitor Banks	4	18,000	12
49	2		Capacitor Banks	2	6,000	13
56	2		Capacitor Banks	5	36,000	14
			Capacitor Banks	1	24,000	15
960	3		Capacitor Banks	3	108,000	16
56	2		Capacitor Banks	4	12,000	17
45	2		Capacitor Banks	4	12,000	18
33	1					19
400	8		Capacitor Banks	25	150,000	20
375	3					21
22	1		Capacitor Banks	2	6,000	22
						23
84	3		Capacitor Banks	6	18,000	24
56	2		Capacitor Banks	2	6,000	25
56	2					26
56	2		Capacitor Banks	4	13,200	27
22	1		Capacitor Banks	2	7,200	28
112	4		Capacitor Banks	5	15,600	29
			Capacitor Banks	1	24,000	30
56	2		Capacitor Banks	4	13,200	31
56	2		Capacitor Banks	4	12,000	32
84	3		Capacitor Banks	6	18,000	33
						34
						35
						36
464	4	1				37
170	1					38
480	3					39
685	3	1				40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
55	1					1
55	1					2
80	3					3
						4
						5
596	2	1				6
22	1					7
164	3					8
100	2					9
300	3	1				10
						11
			Series Capacitor	1	363,000	12
						13
572	2					14
						15
640	2					16
						17
168	1					18
			Reactors	3	180,000	19
53	3	1				20
						21
120	3	1				22
3	1					23
900	3	1				24
40	2					25
			Series Capacitor	1	546,000	26
640	2					27
						28
			Series Capacitor	1	546,000	29
						30
320	2		Capacitors/Reactors	6	90,000	31
20970	383	17		443	3,611,966	32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Schedule Page: 426 Line No.: 12 Column: a

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

Schedule Page: 426 Line No.: 13 Column: a

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

Schedule Page: 426.1 Line No.: 16 Column: a

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

Schedule Page: 426.1 Line No.: 22 Column: a

Switching only.

Schedule Page: 426.1 Line No.: 31 Column: a

Regulating only.

Schedule Page: 426.1 Line No.: 32 Column: a

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

Schedule Page: 426.2 Line No.: 11 Column: b

Footnote for Asset Reclassification

On September 6, 2019, PGE filed a petition for declaratory order in Docket No. EL19-95-00 seeking to reclassify certain 57 kV and 115 kV facilities from distribution to transmission. The case was held in abeyance, pending the outcome of a parallel proceeding before the OPUC.

On November 22, 2019, PGE filed a motion to supplement the petition to include the OPUC's decision in Docket No. UM 2031, which granted reclassification of a subset of the facilities. The stipulation in OPUC Order No. 19-400 identified four characteristics that reflect the reclassification:

A. Radial lines both to distribution and to customers tend to be distribution, but radial generation tie facilities tend to be transmission for accounting purposes but should be classified as production for ratemaking purposes;

B. Non-radial line segments of 100 kV or higher voltage tend to be transmission;

C. Transformers with a secondary voltage under 100 kV tend to be distribution; and

D. Substation assets (e.g. circuit breakers) that are part of the path that connect the transmission line segments, or equipment associated with transformers with a secondary voltage higher than 100 kV, are considered transmission

The FERC approved the reclassification of identified facilities on December 31, 2019. As a result, PGE reclassified certain 115 kV facilities from distribution to transmission.

Schedule Page: 426.4 Line No.: 5 Column: a

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 76% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.4 Line No.: 6 Column: a

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 76% share of the jointly owned capacity. 100% of the capacity is reported.

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

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Switching only. Distribution owned by Columbia River PUD.

Schedule Page: 426.4 Line No.: 15 Column: a

Switching only. Distribution owned by Columbia River PUD.

Schedule Page: 426.4 Line No.: 23 Column: a

Switching only

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

Switching only

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

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

Schedule Page: 426.4 Line No.: 40 Column: a

Jointly owned with Idaho Power Company. PGE has an 90% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.5 Line No.: 1 Column: a

Jointly owned with Idaho Power Company. PGE has an 90% share of the jointly owned capacity, 100% of the capacity is reported.

Schedule Page: 426.5 Line No.: 2 Column: a

Jointly owned with Idaho Power Company. PGE has an 90% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.5 Line No.: 3 Column: a

Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. PGE has a 16% share of the jointly owned capacity. 100% of the capacity is reported.

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

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

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

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

Schedule Page: 426.5 Line No.: 8 Column: a

Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. PGE has a 20% share of jointly owned capacity. 100% of the capacity is reported.

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

Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. PGE has a 14% share of the jointly owned capacity. 100% of the capacity is reported.

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

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

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

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

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

Line compensation only.

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

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

Schedule Page: 426.5 Line No.: 17 Column: a

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

Schedule Page: 426.5 Line No.: 19 Column: a

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

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

Switching only. Identified location is a Bonneville Power Administration owned and

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

operated substation at which respondent owns switching and/or regulating equipment.

Schedule Page: 426.5 Line No.: 22 Column: a

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

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

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

Schedule Page: 426.5 Line No.: 26 Column: a

Line compensation only.

Schedule Page: 426.5 Line No.: 28 Column: a

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

Schedule Page: 426.5 Line No.: 29 Column: a

Line compensation only.

Schedule Page: 426.5 Line No.: 30 Column: a

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2019/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3	Lease Payments for Corporate Headquarters	121 SW Salmon Street Corp	418	8,933,735
4	OPUC Order No. 18-823			
5				
6	Catering Services	Salmon Springs Hospitality Group	921	904,790
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22	Administrative Services	Salmon Springs Hospitality Group	186	1,194,717
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2019/Q4

FOOTNOTE DATA

Schedule Page: 429 Line No.: 3 Column: d

Prior to November 2018:

121 Southwest Salmon Street Corp maintained the lease with the landlord and billed PGE on a monthly basis. PGE incurred all the costs associated with operating and maintaining the property.

Starting November 2018:

121 Southwest Salmon Street Corp purchased the property from the landlord and now incurs all the costs associated with operating and maintaining the property. It charges PGE base rent plus a proportionate share of expenses via a monthly allocation. Consequently, the total rent charged by 121 Southwest Salmont Street Corp to PGE is much higher than prior years.

INDEX

INDEX (continued)

INDEX (continued)

INDEX (continued)

INDEX (continued)