e-FILING REPORT COVER SHEET

COMPANY NAME: Portland General Electric - Annual Report for the year ending December 31, 2018

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

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

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

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

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

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

PGE's 2018 FERC Form 1; PGE's 2018 Oregon Supp to FERC Form 1; and PGE's 2018 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
121 SW Salmon Street • Portland, Ore. 97204
PortlandGeneral.com

May 1, 2019

Electronic Mail
puc.filingcenter@state.or.us

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

RE: PGE FERC Form 1 and Oregon Supplemental

PGE filed its RE 54 Report today in two parts. The e-filed portion of the filing contains the cover letter, cover sheet and an electronic version of PGE's 2018 Annual Shareholder Report. The remainder of the filing is being provided through a CD due to the volume of material being provided and as directed, PGE has sent the CD to the "Filing Center, Annual reports, PO Box 1088, Salem, Oregon 97308-1088".

The CD contains:

1) PGE's 2018 FERC Form 1 (.PDF) and the final pre-closing rail balance by FERC Account in Excel format;
2) PGE's Oregon Supplement to the 2018 FERC Form 1 (.PDF, Excel and Word);
3) PGE's Oregon Jurisdiction – Distribution of Salaries and Wages; and
4) Miscellaneous Excel files from PGE's Oregon Supplement to the 2018 FERC Form 1.

Not included in this package is the requested "final pre-closing trial balance worksheet". PGE will file this worksheet as soon as it is available.

Per the February 12, 2019 notice of documentation to be forwarded, is a new requirement for five printed copies of PGE's 2018 Annual Report. PGE advised Marianne Gardner that the 2018 Annual Report is not available in hardcopy as the 2018 Annual Report was provided to Shareholders in digital format only. The link to that Report and PGE's FERC Form 1 are provided below:

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

PGE FERC Form 1:
http://investors.portlandgeneral.com/static-files/ba1fb7b7-148b-45fb-9f30-e360983c3c5b
If you have any questions or require further information, please call me at 503-464-7805. Please direct all formal correspondence, questions, or requests to the following e-mail address: pge.opuc.filings@pgn.com.

Sincerely,

Stefan Brown
Manager, Regulatory Affairs

SB/lh

cc: Marianne Gardner, OPUC

cc: CD provided to OPUC Filing Center (Annual Reports)

Portland General Electric

2018 ANNUAL REPORT

To our shareholders:

One year ago, I shared my enthusiasm for the opportunity to lead PGE and for a clean energy future. Looking back, 2018 marked a year of focus on operational excellence and transformation. We established a clear, unified direction based on decarbonizing our electricity supply, expanding electricity use — especially in the transportation sector — and updating and modernizing our grid.

PGE's strong financial performance, combined with our solid track record of safe, reliable, affordable, clean and secure energy delivery, continues to build long-term value for all of our stakeholders. I'm pleased to share our 2018 results.

OPERATIONAL ACHIEVEMENTS

Our service area is thriving, with large-scale commercial and industrial growth and a strong labor market averaging 3.5 percent unemployment.[1] Oregon ranks second nationwide for in-migration moves[2], which have contributed to a 1.2 percent increase in customers to 885,000 in 2018.

Operationally, results were strong. Our distribution system performed well with high reliability. We reduced the number and duration of service disruptions and improved service-restoration times over the prior year. Power supply and generation also performed better than in 2017, and our power plants achieved 93 percent availability.

The new Customer Touchpoints system went live mid-year, replacing outdated technology with a new integrated billing platform to better meet future customer needs. PGE again rated in the top decile[3] for customer satisfaction among business and residential customer groups. For the ninth year in a row, our voluntary renewable program was No. 1 in the nation.

Capital expenditures were $595 million. In addition to replacing and upgrading aging generation, transmission and distribution equipment, we continued to strengthen our grid against earthquakes, cyberattacks and other potential threats.

This year, we announced our commitment to reduce greenhouse gas emissions by 80 percent or more by 2050 and accelerated our path forward. We completed the final element of our 2016 Integrated Resource Plan with the regulatory and Renewable Request for Proposal processes that culminated in the Wheatridge Renewable Energy Facility, a collaboration with NextEra Energy Resources. Once online, the additional resources will allow PGE to meet about 50 percent of our customers' power needs with renewable energy.

To advance a smarter, more integrated grid, we announced the largest Smart Grid Test Bed yet. We laid the groundwork to modernize the grid for a two-way exchange of power and information enhanced by technologies to make our system smarter, more efficient and reliable.

1. State of Oregon Employment Department, three county average
2. United Van Lines 2018 National Movers Study
3. Market Strategies International

Finally, we made significant progress on our Transportation Electrification Plan after the Oregon Public Utility Commission's approval in early 2018.

We developed partnerships with our largest municipal customers. We are bringing new Electric Avenue charging stations to the region, while also strengthening our collaboration with mass transit.

From transportation electrification to ambitious, industry-leading programs, we are bringing fresh energy and collaborating with stakeholders.

FINANCIAL PERFORMANCE

We delivered a strong performance this year with net income of $212 million, or $2.37 per diluted share. Total shareholder return was 5.6 percent, including dividends of $1.41 per share.

Full-year earnings guidance for 2019 is $2.35 to $2.50 per diluted share, and we provided guidance for 4 to 6 percent average annual earnings growth from 2018 through 2021.

LOOKING FORWARD

In 2019, we are committed to serving customers with competitive energy options and services, top-quartile system reliability and plant availability. We aim for our renewable energy program to continue to be the No. 1 nationwide for a 10th consecutive year. We are eager to lead the way in Oregon and as a model for our industry.

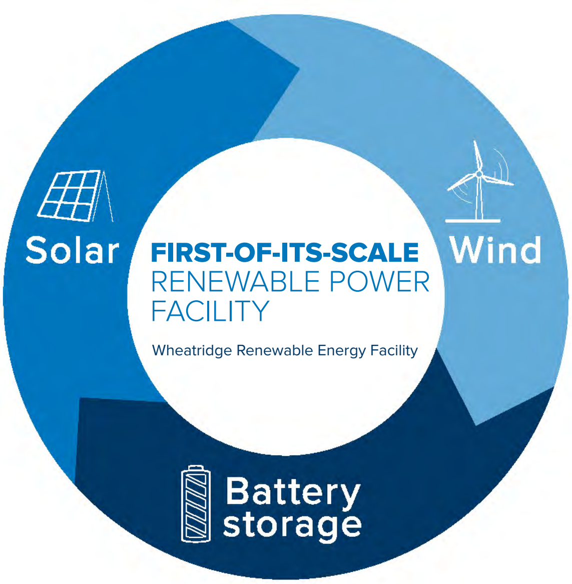
I would like to thank our more than 2,900 dedicated employees, who help power our customers' lives every day. We have exciting opportunities ahead as we continue investing in renewable energy and a smarter grid. We are also facing new challenges that demand excellence in all that we do.

Finally, I would like to thank David Dietzler for his dedication and more than 13 years of service to our board of directors. David will retire from the board in April at the time of our annual meeting. I also welcome our newest board member, Michael Millegan.

Maria M. Pope
President and Chief Executive Officer

NORTH AMERICA'S FIRST MAJOR RENEWABLE ENERGY FACILITY TO COMBINE WIND, SOLAR AND BATTERY STORAGE IN ONE LOCATION

The Wheatridge Renewable Energy Facility will include 300 megawatts of wind generation, 50 megawatts of solar power and 30 megawatts of battery storage. PGE will own 100 megawatts of the project and consume the entire output through power purchase agreements.



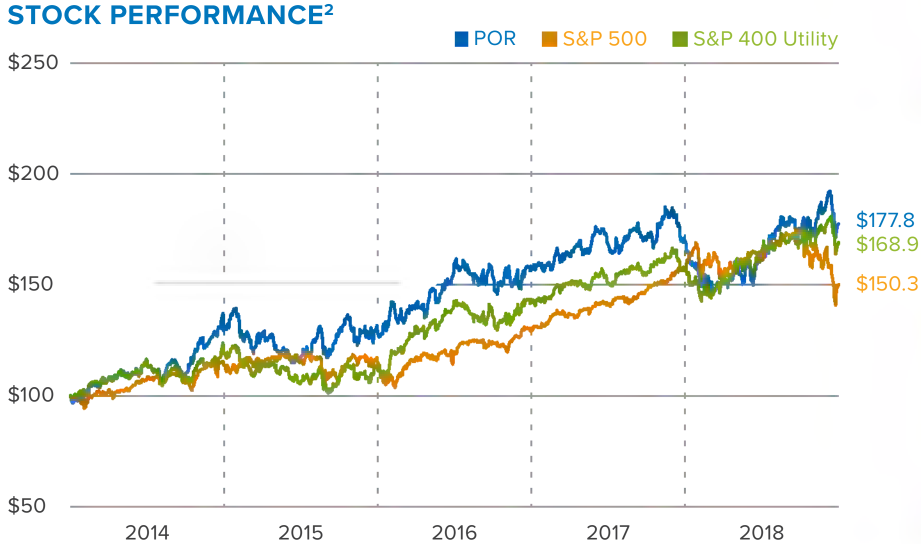
Financial highlights

ABOUT PORTLAND GENERAL ELECTRIC

Portland General Electric Company, headquartered in Portland, Oregon, is a fully integrated electric utility serving approximately 885,000 residential, commercial and industrial customers in Oregon. We have been powering Oregon for more than 125 years. PGE common stock is traded on the New York Stock Exchange under the ticker symbol POR.

(Dollars in millions, except per-share amounts)	2018	2017	2016
Operating revenues	$1,991	$2,009	$1,923
Net operating income	$346	$380	$340
Net income for common stock	$212	$187[1]	$193
Earnings per share, diluted	$2.37	$2.10[1]	$2.16
Return on average equity	8.6%	7.9%	8.4%
Dividends declared per common share	$1.4275	$1.340	$1.260
Weighted-average shares outstanding (in thousands), diluted	89,347	89,176	89,054
FOLLOWING DATA AS OF YEAR-END			
Total assets	$8,110	$7,838	$7,527
Long-term debt, including current portion	$2,478	$2,426	$2,350
Long-term debt/capitalization	50.2%	50.6%	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	885,000	875,000	863,000
Employees	2,967	2,906	2,752

STOCK PERFORMANCE[2]



TOTAL RETAIL REVENUE

NET INCOME

EARNINGS PER SHARE (DILUTED)

CAPITAL EXPENDITURES

1. Non-GAAP net income and diluted earnings per share excluding the effects of the federal Tax Cuts and Jobs Act was $204 million and $2.29 respectively.
2. The chart above assumes a $100 investment in Portland General Electric's common stock and each index on Dec. 31, 2013, and that all dividends were reinvested.

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

FORM 10-K

[x] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2018

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:

Common Stock, no par value	**New York Stock Exchange**
(Title of class)	(Name of exchange on which registered)

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 [x] 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 [x]

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 [x]   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 [x]   No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [x]

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	[x]	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 [x]

As of June 30, 2018, the aggregate market value of voting common stock held by non-affiliates of the Registrant was $3,802,406,147. For purposes of this calculation, executive officers and directors are considered affiliates.

As of February 4, 2019, there were 89,269,775 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 24, 2019.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2018

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
DEQ	Oregon Department of Environmental Quality
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
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 approximately 4,000 square miles is located entirely within Oregon and includes 51 incorporated cities, of which Portland and Salem are the largest. The Company estimates that at the end of 2018 its service area population was 1.9 million, comprising 46% of the population of the State of Oregon. During 2018, the Company added nearly 10,000 customers, and as of December 31, 2018, served a total of 885,000 retail customers.

Employees

PGE had 2,967 employees as of December 31, 2018, with 802 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 747 and 55 employees and expire March 2020 and August 2022, respectively.

Available Information

PGE's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 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. Information may also be obtained via the SEC website at sec.gov.

Regulation

Federal and State of Oregon regulation both can 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 generation, in real time, and the restriction on sales 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. As required by the OATT, PGE provides information regarding its electric transmission business on its Open Access Same-time Information System, also known as OASIS.

Reliability and Cyber Security Standards—Pursuant to the Energy Policy Act of 2005, 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. These standards include Critical Infrastructure Protection standards, a set of cyber security standards that provide a framework to identify and protect critical cyber assets used to support reliable operation of the bulk power system.

Natural Gas Pipelines—The Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 provide the FERC 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 the Company's natural gas-fired generating plants located near Clatskanie, Oregon: Port Westward Unit 1 (PW1); Port Westward Unit 2 (PW2); and Beaver. 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—Under the FPA, PGE's hydroelectric generating plants are subject to FERC licensing requirements. PGE holds FERC licenses for the Company's projects on the Deschutes, Clackamas, and Willamette Rivers. The licenses specify certain operating procedures and require capital projects focused on fish protection and reintroduction. 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—Pursuant to applicable provisions of the FPA, PGE prepares 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 Trojan nuclear power plant (Trojan), which was closed in 1993. The NRC approved the 2003 transfer of spent nuclear fuel from a spent fuel pool to a separately licensed dry cask storage facility that will house the fuel on the former plant site until a United States Department of Energy (USDOE) facility is available. Radiological decommissioning of the plant site was completed in 2004 under an NRC-approved plan, with the plant's operating license terminated in 2005. Spent fuel storage activities will continue to be subject to NRC regulation until all nuclear fuel is removed from the site and radiological decommissioning of the storage facility is completed. 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."

State of Oregon Regulation

PGE is subject to the jurisdiction of the OPUC and a number of other state agencies, as described in the discussion that follows.

The OPUC, comprised of three members appointed by the governor of Oregon to serve non-concurrent four-year terms, reviews and approves the Company's retail prices (see "*Economic Regulation*" below) and establishes conditions of utility service. In addition, the OPUC reviews the Company's generation and transmission resource acquisition plans, pursuant to a bi-annual 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.

Economic Regulation—Under Oregon law, the OPUC is required to: i) ensure that prices and terms of service are fair and non-discriminatory; and ii) provide regulated companies an opportunity to earn a reasonable return on their investments. 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, which are conducted under established procedural schedules, 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 to sufficiently cover its operating costs and provide a reasonable rate of return to investors. Price changes are requested pursuant to a comprehensive general rate case process that reflects revenue requirements based on a forecasted test year. Through this public review process, 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 Cases*" in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."
- *Power Costs*. In addition to price changes resulting from the general rate case process, 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.* In 2007, the State of Oregon established a Renewable Portfolio Standard (RPS), which requires that PGE serve a portion of its retail load with renewable resources. The RPS allows renewable energy certificates (RECs), resulting from energy generated from qualified renewable resources, and generation from certified low impact hydroelectric power resources, to be used to meet those requirements. In addition, a renewable adjustment clause (RAC) mechanism was established that allows for the recovery in customer prices of prudently incurred costs to comply with the RPS. In 2016, the State of Oregon passed a law referred to as the Oregon Clean Electricity and Coal Transition Plan (SB 1547), which, among its provision, increased the RPS percentages in certain future years.

As needed, other ratemaking proceedings may occur and can involve charges or credits related to specific costs, programs, or activities, as well as the recovery or refund of deferred amounts recorded pursuant to specific OPUC authorization. Such amounts are generally collected from, or refunded to, retail customers through the use of supplemental tariffs.

For additional information see the *"Legal, Regulatory, and Environmental Matters"* discussion in the Overview section in 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). 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 a New Large Load Direct Access program, capped at approximately 120 MWa, for unplanned, large, new loads and large load growth at existing sites. Customers who choose Direct Access purchase energy from an ESS and PGE receives revenue only for the transmission and delivery of the electricity.

Transition adjustments, intended to ensure that the costs or benefits of the program do not unfairly shift to those customers that continue to purchase their energy requirements from the Company on cost of service pricing, are charged to Direct Access and market-based pricing customers if market energy prices are below PGE's fixed generation costs (or credited to, if market prices are above). 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."

Energy Efficiency Funding—Oregon law provides for a public purpose charge to fund cost-effective energy efficiency measures, new renewable energy resources, and weatherization measures for low-income housing. This charge, equal to 3% of retail revenues, is collected from customers and remitted to the Energy Trust of Oregon (ETO) and other agencies for administration of these programs. The Company collected $52 million from customers for this charge in 2018, $53 million in 2017, and $50 million in 2016.

In addition to the public purpose charge, PGE also remits to the ETO amounts collected from its customers under an Energy Efficiency Adjustment tariff to fund additional energy efficiency measures. This charge was 3.7%, 3.6%, and 2.7% of retail revenues for applicable customers in 2018, 2017, and 2016, respectively. Under the tariff, $66 million was collected from eligible customers in both 2018 and 2017, and $48 million was collected in 2016.

Siting—Oregon's Energy Facility Siting Council (EFSC) has responsibility for overseeing the development of large electric generating facilities, certain high voltage transmission lines, intrastate gas pipelines, and radioactive waste disposal sites.

Regulatory Accounting

PGE is subject to accounting principles generally accepted in the United States of America (GAAP) and, as a regulated public utility, the effects of rate regulation are reflected in its financial statements. These principles provide 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 within a service area approved by the OPUC. 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) fuel oil suppliers, primarily for residential customers' space heating needs. 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 10% of total retail deliveries. While the twenty largest commercial and industrial customers constituted 12% of total retail revenues in 2018, they represented ten different groups including high tech and other manufacturing, health care services, governmental agencies, data centers, and retailers.

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

	Years Ended December 31,								
	2018			2017			2016		
Retail revenues[1] (dollars in millions):									
Residential	$	948	53%	$	969	52%	$	907	51%
Commercial		665	37		669	36		665	37
Industrial		210	12		212	11		208	12
Subtotal		1,823	102		1,850	99		1,780	100
Alternative revenue programs, net of amortization		3	—		—	—		—	—
Other accrued (deferred) revenues, net[2]		(45)	(2)		10	1		3	—
Total retail revenues	$	1,781	100%	$	1,860	100%	$	1,783	100%
Retail energy deliveries[3] (MWh in thousands):									
Residential		7,416	39%		7,880	40%		7,348	39%
Commercial		7,430	39		7,555	38		7,457	39
Industrial		4,376	22		4,283	22		4,166	22
Total retail energy deliveries		19,222	100%		19,718	100%		18,971	100%
Average number of retail customers:									
Residential		772,389	88%		762,211	88%		752,365	88%
Commercial		109,107	12		107,855	12		106,773	12
Industrial		270	—		267	—		258	—
Total		881,766	100%		870,333	100%		859,396	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) Activity for the year ended December 31, 2018 primarily relates to the regulatory liability deferral of the 2018 net tax benefits due to the change in corporate tax rate under the Tax Cuts and Jobs Act of 2018 (TCJA). For further information, see Note 12, Income Taxes in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."
(3) Includes both energy sold to retail customers and energy deliveries to those commercial and industrial customers that purchase their energy from ESSs.

Additional averages for retail customers are as follows:

	Years Ended December 31,					
	2018		2017		2016	
Residential						
Revenue per customer (in dollars):	$	1,153	$	1,181	$	1,114
Usage per customer (in kilowatt hours):		9,601		10,338		9,766
Revenue per kilowatt hour (in cents):		12.01¢		11.42¢		11.40¢
Commercial						
Revenue per customer (in dollars):	$	6,051	$	6,142	$	6,166
Usage per customer (in kilowatt hours):		68,096		70,046		69,839
Revenue per kilowatt hour (in cents):		8.89¢		8.77¢		8.83¢
Industrial						
Revenue per customer (in dollars):	$	776,245	$	792,466	$	804,953
Usage per customer (in kilowatt hours):		16,207,263		16,041,461		16,146,371
Revenue per kilowatt hour (in cents):		4.79¢		4.94¢		4.99¢

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 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 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. Additional information on the customer classes follows.

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 twenty 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; strong job growth and population growth in PGE's service territory have led to increasing 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.

During 2018, total residential deliveries decreased 5.9% compared with 2017. PGE witnessed a 1.3% increase in the average number of residential customers served during the year while average usage per customer decreased 7.1% driven by unfavorable weather compared to the prior year. Temperatures in 2018 were characterized by both a mild heating season and a milder cooling season over the summer months, decreasing residential energy deliveries. The year-over-year impact was intensified by cold during the heating season in 2017, which increased residential energy deliveries in that year. On a weather-adjusted basis, energy deliveries to residential customers increased by 0.2% in 2018 when compared with 2017.

During 2017, total residential deliveries increased 7.2% compared with 2016. PGE witnessed a 1.3% increase in the average number of residential customers served during the year and average usage per customer increased 5.9% driven by favorable weather compared to the prior year. Temperatures in 2017 were characterized by both a cold heating season in the first quarter and a warm cooling season over the summer months, increasing residential energy deliveries. The year-over-year impact was intensified by unseasonably warm heating season temperatures seen in 2016, which decreased residential energy deliveries in that year. On a weather-adjusted basis, energy deliveries to residential customers decreased by 2.2% in 2017 when compared with 2016.

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 customers are somewhat less susceptible to weather conditions than are residential customers, although weather does affect commercial demand to some extent. 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.

In 2018, a heating season that was more mild than the prior year drove a 1.7% decrease in commercial deliveries compared with 2017. Weather-adjusted, deliveries to commercial customers decreased by 0.4% in 2018. Deliveries to several retail sectors decreased, including food and merchandise stores and health care, while other service sectors, including data centers, showed growth. Energy efficiency continues to impact growth, and conservation and building codes and standards are likely reducing energy deliveries beyond the impact of energy efficiency programs.

In 2017, a 1.0% growth in the average number of commercial customers and a cold first quarter heating season drove a 1.3% increase in commercial deliveries compared with 2016. Weather-adjusted, deliveries to commercial customers decreased by 0.7% in 2017. Deliveries to several retail sectors decreased, including food and merchandise stores and office, finance, insurance, and real estate. These decreases were only partially offset by increases in the miscellaneous and other services sectors, which are driven by a strong construction cycle and data center growth.

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 on the applicable tariff. Demand from industrial customers is primarily driven by economic conditions, with weather having little impact on this customer class.

The Company's industrial energy deliveries increased 2.2% in 2018 from 2017, reflecting increases across several manufacturing sectors, with the strongest increases due to customers in high tech manufacturing and their suppliers. The 2.8% increase in 2017 from 2016 reflected increases across several manufacturing sectors, with the strongest increases to customers in high tech manufacturing and their suppliers. These increases have occurred even though the Company experienced the loss of a large paper manufacturing customer that ceased operations in October 2017, which reduced comparative annual industrial deliveries for a portion of 2017 and all of 2018.

Other accrued (deferred) revenues, net include items that are not currently in customer prices but are expected to be in prices in a future period. Such amounts include, among other things, deferrals recorded under the RAC, the decoupling mechanism, and deferral of the 2018 net tax benefits due to the change in corporate tax rate under the TCJA. For further information on the RAC and decoupling items, see "*Legal, Regulatory and Environmental Matters*" in the Overview section of Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations. For further information on the TCJA, see Note 12, Income Taxes in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

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 and wind conditions, and daily and seasonal retail demand. Wholesale revenues represented 8% of total revenues in 2018 and 5% in each of the prior two years.

The majority of PGE's wholesale electricity sales is to utilities and power marketers and is predominantly short-term. The Company may choose to net its purchases and sales with the same counterparty rather than simultaneously receiving and delivering physical power; in such cases, only the net amount of those purchases or sales required to meet retail and wholesale obligations will be physically settled.

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, excess fuel sales, pole contact rentals, and other electric services provided to customers. Other operating revenues represented 3% of total revenues in 2018 and 2% in each of the prior two years.

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 provide cumulative variances in the average daily temperature from a baseline of 65 degrees, over a period of time, to indicate the extent to which customers are likely to use, or have used, electricity for heating or air conditioning. 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
2018	3,702	692
2017	4,558	700
2016	3,552	548
15-year average	4,117	514

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 July, August, and 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 has experienced its highest peak loads during summer in each of the past three years:

	Winter Loads			Summer Loads		
	Average	Peak	Month	Average	Peak	Month
2018	2,519	3,399	February	2,349	3,816	August
2017	2,698	3,727	January	2,380	3,976	August
2016	2,537	3,716	December	2,246	3,726	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 relies upon its generating resources, as well as wholesale power purchases from third parties to meet its customers' energy requirements. 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 current long-term wholesale contracts. The Company also promotes energy efficiency measures to meet its energy requirements.

PGE's generating resources consist of seven thermal plants (natural gas- and coal-fired), two wind farms, and seven hydroelectric facilities. Capacity of the thermal plants represents the MW the plant is capable of generating under normal operating conditions, which is affected by ambient temperatures, net of electricity used in the operation of the plant. Capacity of both hydro and wind generating resources represent the nameplate MW, which varies from actual energy expected to be received as these types of generating resources are highly dependent upon river flows and wind conditions, respectively. Availability represents the percentage of the year the plant was available for operations, which reflects the impact of planned and forced outages. For a complete listing of these facilities, see "*Generating Facilities*" in Item 2.—"Properties."

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

	As of December 31,					
	2018		2017		2016	
	Capacity	**%**	**Capacity**	**%**	**Capacity**	**%**
Generation:						
Thermal:						
Natural gas	1,830	38%	1,831	39%	1,805	38%
Coal	814	17	814	17	814	17
Total thermal	2,644	55	2,645	56	2,619	55
Wind [(1)]	717	15	717	15	717	15
Hydro [(2)]	495	10	495	10	495	11
Total generation	3,856	80	3,857	81	3,831	81
Purchased power:						
Long-term contracts:						
Capacity/exchange	100	2	100	2	250	5
Hydro	518	11	531	12	534	12
Wind	39	1	39	1	39	1
Solar	46	1	13	—	13	—
Other	27	—	18	—	18	—
Total long-term contracts	730	15	701	15	854	18
Short-term contracts	273	5	185	4	45	1
Total purchased power	1,003	20	886	19	899	19
Total resource capacity	4,859	100%	4,743	100%	4,730	100%

(1) Capacity represents nameplate and differs from expected energy to be generated, which is expected to range from 215 MWa to 290 MWa, dependent upon wind conditions.
(2) Capacity represents net capacity and differs from expected energy to be generated, which is expected to range from 200 MWa to 250 MWa, dependent upon river flows.

For information regarding actual generating output and purchases for the years ended December 31, 2018, 2017, and 2016, see the Results of Operations section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Generation

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.

Thermal The Company has five natural gas-fired generating facilities: PW1, PW2, Beaver, Coyote Springs Unit 1 (Coyote Springs), and Carty. These natural gas-fired generating plants provided approximately 41% of PGE's total retail load requirement in 2018, 33% in 2017, and 32% in 2016.

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. These two coal-fired generating facilities provided approximately 17% of the Company's total retail load requirement in 2018, compared with 18% in 2017, and 19% in 2016. 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 "*Legal, Regulatory, and Environmental Matters*" in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

The thermal plants provide reliable power and capacity reserves for PGE's customers. These resources have a combined capacity of 2,644 MW, representing approximately 69% of the net capacity of PGE's generating portfolio. Thermal plant availability, excluding Colstrip, was 93% in 2018, 88% in 2017, and 92% in 2016, while Colstrip availability was 82% in 2018, compared with 86% in 2017 and 85% in 2016.

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 approximately 450 MW. Tucannon River, placed in service in December 2014, is located in southeastern Washington and consists of 116 wind turbines with a total nameplate capacity of 267 MW.

The energy from wind resources provided 10% of the Company's total retail load requirement in 2018, 9% in 2017, and 10% in 2016. Availability for these resources was 92% in 2018, compared with 96% in 2017 and 95% in 2016. The expected energy from wind resources differs from the nameplate capacity and is expected to range from 135 MWa to 180 MWa for Biglow Canyon and from 80 MWa to 110 MWa for Tucannon River, dependent upon wind conditions.

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. The licenses for these projects expire at various dates ranging from 2035 to 2055. Although these plants have a combined capacity of 495 MW, actual energy received is dependent upon river flows. Energy from these resources provided 8% of the Company's total retail load requirement in 2018, and 9% in both 2017 and 2016, with availability of 93% in 2018, 95% in 2017, and 99% in 2016. Northwest hydro conditions have a significant impact on the region's power supply, with water conditions significantly impacting PGE's cost of power and its ability to economically displace more expensive thermal generation and spot market power purchases.

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 (Tribes). A 50-year joint license for the project, which is operated by PGE, was issued by the FERC in 2005. The Tribes have an option to purchase an additional undivided 16.66% interest in Pelton/Round Butte at its discretion on December 31, 2021. The Tribes have a second option in 2036 to purchase an undivided 0.02% interest in Pelton/Round Butte. If both options are exercised by the Tribes, the Tribes' ownership percentage would exceed 50%.

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, 2018, there were 62 sites with a total DSG capacity of 129 MW. Additional DSG projects are being pursued with a total goal of 135 MW online by the end of 2021.

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

Natural Gas Physical supplies of natural gas are generally purchased up to twelve months in advance of delivery and based on anticipated operation of the plants. PGE attempts to manage 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 Kelso-Beaver Pipeline, which directly connects PW1, PW2, and Beaver to Northwest Pipeline, an interstate natural gas pipeline operating between British Columbia and New Mexico. Currently, PGE transports natural gas on the Kelso-Beaver Pipeline for its own use under a firm transportation service agreement, with capacity offered to others on an interruptible basis to the extent not utilized by the Company. PGE has access to 103,305 Dth per day of firm natural gas transportation capacity to serve the three plants.

PGE also has contractual access to natural gas storage in Mist, Oregon from which it can draw as needed. The Company expects to utilize this resource 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.

PGE has entered into a long-term agreement with NW Natural to expand the current storage facilities, including the development of an underground storage reservoir and construction of a new compressor station and 13-mile pipeline, that will be designed to provide no-notice storage services to these PGE generating plants. Pursuant to the agreement, on September 30, 2016, PGE issued NW Natural a Notice To Proceed with construction of the expansion project, which NW Natural estimates will be completed during the Spring of 2019, at a cost of approximately $144 million.

Beaver has the capability to operate on fuel oil when it is economical or if the plant's natural gas supply is interrupted. PGE had an approximate four-day supply of ultra-low sulfur diesel fuel oil at the plant site as of December 31, 2018. The current operating permit for Beaver limits the number of gallons of fuel oil that can be burned daily, which effectively limits the daily hours of operation of Beaver on fuel oil.

To serve Coyote Springs and Carty, PGE has access to 119,500 Dth per day of firm natural gas transportation capacity on three pipeline systems accessing gas fields in Alberta, Canada. PGE believes that sufficient market supplies of natural gas are available for Coyote Springs and Carty for the foreseeable future, based on anticipated operation of the plants. Although Coyote Springs was designed to also operate on fuel oil, such capability has been deactivated in order to optimize natural gas operations.

Coal

PGE has purchase agreements that, together with existing inventory, will provide coal sufficient for the anticipated operating needs for Boardman during 2019. The coal is obtained from surface mining operations in Wyoming and is delivered by rail under two separate transportation contracts which extend through 2020.

The terms of contracts and the quality of coal are expected to be staged in alignment with required emissions limits. PGE believes that sufficient supplies of coal are available to meet anticipated coal-fired operations of Boardman through 2020.

The Colstrip co-owners currently obtain coal to fuel the plant via conveyor belt from a mine that lies adjacent to the facility and is the sole source of coal supply for the plant. The company that owns and operates the mine declared bankruptcy in the fourth quarter of 2018. Debtors in the bankruptcy proceeding filed notice on January 19, 2019 of their decision to reject the co-owners' current coal contract, which currently extends through December 31, 2019. The co-owners have filed objections to such a plan, and a hearing on the debtor's plan is expected to be held by March 1, 2019. In the event the current coal supply contract is ultimately rejected in bankruptcy, Colstrip and the co-owners may have a material limitation on coal supply for a portion of 2019, and beyond, which may result in increased replacement power costs.

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. Such contracts have original terms ranging from one month to 37 years and expire at varying dates through 2055.

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):

Capacity/exchange—PGE has one contract that provides the Company with firm capacity to help meet peak loads. The agreement allows for up to 100 MW of seasonal peaking capacity during winter periods through February 2019. A new seasonal peaking capacity agreement during the summer and winter periods for 100 MW will begin in July 2019 and continue through February 2024. An additional 200 MW of annual capacity will be added in January 2021, with a five-year term.

Hydro—During 2018, 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 159 MW of capacity that expires in 2028 and one contract representing 163 MW of capacity that expires in 2052. Although the projects currently provide a total of 322 MW of capacity, actual energy received is dependent upon river flows and capacity amounts may decline over time.
- *Confederated Tribes*—PGE has a long-term agreement under which the Company purchases, at index prices, the Tribes' interest in the output of the Pelton/Round Butte hydroelectric project. Although the agreement provides approximately 159 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 the Tribes under which the Tribes have agreed to sell, on modified payment terms, their share of the energy generated from the Pelton/Round Butte hydroelectric project exclusively to the Company through 2024.
- *Other*— PGE has two contracts that provide for the purchase of power generated from hydroelectric projects with an aggregate capacity of 37 MW and contract expiration in 2032.

Wind—PGE has three contracts that provide for the purchase of renewable wind-generated electricity and extend to various dates between 2028 and 2035. The expected energy from these wind contracts differs from the nameplate capacity and is expected to approximate 39 MWa, dependent upon wind conditions.

Solar—PGE has fifteen agreements that expire throughout 2031 to 2037 to purchase power generated from photovoltaic solar projects, which have a combined generating capacity of 40 MW. In addition, the Company operates, and purchases power from two solar projects with an aggregate of approximately 6 MW of capacity. The expected energy from these solar resources will vary from the nameplate capacity due to varying solar conditions.

Other—These primarily consist of long-term contracts to purchase power from various counterparties, including other Pacific Northwest utilities and Qualifying Facilities under the Public Utilities Regulatory Policies Act (QF), over terms extending into 2032.

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. 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 "Integrated Resource Plans" 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 2018, PGE delivered approximately 24 million MWh in its balancing authority area through 1,256 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 transmission and distribution systems are generally located as follows:

- On property owned or leased by PGE;
- Under or over streets, alleys, highways and other public places, the public domain and national forests, and federal and state lands primarily under franchises, easements or other rights that are generally subject to termination;
- Under or over private property primarily pursuant to easements obtained from the record holder of title at the time of grant; and
- Under or over Native American reservations under grant of easement by the Secretary of the Interior or lease or easement by Native American tribes.

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, among other things, particulate matter, hazardous air pollutants, and greenhouse gas emissions (GHGs). 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 equal to 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 (SO_2) allowances awarded under the CAA. The current and expected future SO_2 allowances, along with the emissions controls and the continued use of low sulfur fuel, are anticipated to be sufficient to permit the Company to meet its air emissions compliance requirements.

Climate Change—In 2015, the 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 February 2016, the United States Supreme Court granted a stay, halting implementation and enforcement of the CPP.

On August 21, 2018, the EPA proposed the Affordable Clean Energy (ACE) rule, which would replace the CPP and establish emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired plants. The public comment period on the proposed ACE rule closed on October 31, 2018. The EPA has yet to finalize the rule.

The Company continues to monitor the developments around the CPP and the potential new rule. The Company cannot predict the ultimate outcome of the legal challenges to, and the regulatory process of, the EPA, or whether Oregon and Montana will implement the rules or how the rules may impact the Company's operations.

Any laws that would impose emissions taxes or mandatory reductions in GHG emissions may have a material impact on PGE's operations, as the Company utilizes fossil fuels in its own power generation and other companies use such fuels to generate power that PGE purchases in the wholesale market. If incremental costs were incurred as a result of changes in the regulations regarding GHGs, the Company would seek recovery in customer prices. PGE's natural gas-fired facilities, Beaver, Coyote Springs, PW1 and PW2, Carty, and the Company's ownership interest in coal-fired facilities, Boardman and Colstrip, provided, in total, approximately 69% of the Company's net generating capacity at December 31, 2018.

For more information regarding the CPP, see the "*Legal, Regulatory, and Environmental Matters*" 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 18, 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 that have declined significantly over the last several decades. Long-term recovery plans for these species continue to have operational impacts on many of the region's hydroelectric projects. PGE purchases power in the wholesale market, some of which is sourced from affected hydroelectric facilities in the Pacific Northwest, to serve its retail load requirements.

PGE continues to implement fish protection measures at its hydroelectric projects on the Clackamas, Deschutes, and Willamette rivers that were prescribed by the U.S. Fish and Wildlife Service (USFWS) and the National Marine Fisheries Service under their authority granted in the ESA and the FPA. As a result of measures contained in their operating licenses, the Deschutes River and Willamette River projects have been certified as low impact hydro, with a total of 50 MWa of output from those facilities included as part of the Company's renewable energy portfolio used to meet the requirements of the RPS. 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. In 2015, PGE submitted an application for a permit, along with a draft Eagle Conservation Plan, to the USFWS, pertaining to Biglow Canyon that would address the incidental take of eagles, and submitted a similar draft application for Tucannon River in 2017.

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.

The generation of electricity at Boardman and Colstrip produces by-products known as coal combustion residuals (CCRs). In December 2014, the EPA signed a final rule, which became effective in October 2015, to regulate CCRs under the RCRA. PGE has determined that it will continue use of the on-site landfill in compliance with the CCR rule, and the Company believes the CCR rule will not have a material effect on operations at Boardman. For further information, see Note 2, Summary of Significant Accounting Policies and *"Utility plant"* in Note 8, Asset Retirement Obligations, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

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, has revealed significant contamination of river sediments and prompted the EPA to subsequently designate Portland Harbor as a Superfund site. The EPA has listed PGE among the more than one hundred Potentially Responsible Parties (PRPs) in this matter, as PGE has historically owned or operated property near the river. For additional information regarding the EPA action on Portland Harbor, see Note 18, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Under the Nuclear Waste Policy Act of 1982, the USDOE 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 spent nuclear fuel is expected to remain in the ISFSI 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 2034. 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."

Executive Officers

The following are PGE's current executive officers:

Name	Age	Current Position and Previous Experience	Year Appointed Officer
Larry N. Bekkedahl	58	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 August 2014).	2014
Bradley Y. Jenkins	55	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	58	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	45	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	60	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
Anne F. Mersereau	56	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	60	Vice President, Utility Technical Services (January 2019 to present), Vice President, Customer Service, Transmission and Distribution (April 2011 to January 2019), 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).	2007
Maria M. Pope	54	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	52	Vice President, Public Policy (August 2009 to present), Director of Government Affairs (June 2004 to August 2009).	2009
Kristin A. Stathis	55	Vice President, Customer Solutions (January 2019 to present), 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.

From time to time 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 18, 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 snow pack 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 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 GHG emissions from the Company's fossil fuel-fired generation facilities. Compliance with any GHG emissions reduction requirements could require PGE to incur significant expenditures, including those related to carbon capture and sequestration technology, purchase of emission allowances and offsets, fuel switching, and the replacement of high-emitting generation facilities with lower-emitting facilities.

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

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

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.

Measures required to comply with state and federal regulations related to air emissions and water discharges from thermal generating plants could result in increased capital expenditures and operating costs and reduce generating capacity, which could adversely affect the Company's results of operations.

PGE is subject to state and federal requirements concerning air emissions and water discharges from thermal generating plants. For additional information, see the Environmental Matters section in Item 1.—"Business." These requirements could adversely affect the Company's results of operations by requiring: i) the installation of additional air emissions and water discharge controls at PGE's generating plants, which could result in increased capital expenditures; and ii) changes to the Company's operations that could increase operating costs and reduce generating capacity.

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 plan. 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 pension plan. Additionally, changes in interest rates affect PGE's liabilities under the pension plan. 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.

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.

Failure of PGE's wholesale suppliers to perform their contractual obligations could adversely affect the Company's ability to deliver electricity and increase the Company's costs.

PGE relies on suppliers to deliver natural gas, coal, and electricity, in accordance with short- and long-term contracts. Failure of suppliers to comply with such contracts in a timely manner could disrupt the Company's ability to deliver electricity and require PGE to incur additional expenses in order to meet the needs of its customers. In addition, as these contracts expire, the Company could be unable to continue to purchase natural gas, coal, or electricity on terms and conditions equivalent to those of existing agreements.

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.

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, 2018 (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, 2018, PGE owned an electric transmission system consisting of 1,256 circuit miles as follows: 287 circuit miles of 500 kV line; 410 circuit miles of 230 kV line; and 559 miles of 115 kV line. The Company also has 27,627 circuit miles of distribution lines that deliver electricity to its customers.
The Company also has an ownership interest in, and capacity on, the following:

- Approximately 15% of the Colstrip Transmission facilities from Colstrip to BPA's transmission system; and
- Approximately 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:

- Approximately 3,715 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 18, 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 New York Stock Exchange (NYSE) under the ticker symbol "POR".

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,				
	2018	2017	2016	2015	2014
	(In millions, except per share amounts)				
Statement of Income Data:					
Total revenues	$ 1,991	$ 2,009	$ 1,923	$ 1,898	$ 1,900
Income from operations*	346	380	340	318	303
Net income	212	187	193	172	174
Net income attributable to Portland General Electric Company	212	187	193	172	175
Earnings per share—basic	2.38	2.10	2.17	2.05	2.24
Earnings per share—diluted	2.37	2.10	2.16	2.04	2.18
Dividends declared per common share	1.4275	1.340	1.260	1.180	1.115
Statement of Cash Flows Data:					
Capital expenditures	595	514	584	598	1,007

* The years ended December 31, 2014 and 2015 include a $10 million and $9 million reclassification of the non-service cost component of net periodic pension and postretirement benefit costs, respectively, as such costs are no longer considered in the subtotal of Income from operations pursuant to the adoption of ASU 2017-07, *Compensation-Retirement Benefits (Topic 715), Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. For information regarding this matter, see “Recently Adopted Accounting Pronouncements” in Note 2, Summary of Significant Accounting Policies, in the Notes to Consolidated Financial Statements in Item 8.—“Financial Statements and Supplementary Data.”

	As of December 31,				
	2018	2017	2016	2015	2014
	(Dollars in millions)				
Balance Sheet Data:					
Total assets	$ 8,110	$ 7,838	$ 7,527	$ 7,210	$ 7,030
Total long-term debt	2,478	2,426	2,350	2,193	2,489
Total capital lease obligations	49	51	54	—	—
Total shareholders’ equity	2,506	2,416	2,344	2,258	1,911
Common equity ratio	49.8%	49.4%	49.4%	50.7%	43.4%

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;
- the outcome of legal and regulatory proceedings and issues including, but not limited to, the matters described in Note 18, 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;
- 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;

- declines in the fair value of securities held for the defined benefit pension plans and other benefit plans, which could result in increased funding requirements for such plans;
- 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 a significant number of employees approaching retirement;
- 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's mission is to provide an accessible, affordable clean energy future to customers in all of the communities it serves, responding proactively to an evolving landscape of customer expectations, technology changes, and regulatory frameworks by focusing efforts on four strategic initiatives: i) delivering exceptional customer service; ii) investing in a reliable and clean energy future; iii) building a smarter, more resilient grid; and iv) pursuing excellence in its work.

By choosing renewable sources, like solar, wind, and water, PGE can supply power without creating carbon emissions. As the largest electric utility in Oregon, bringing customers renewable power is one of PGE's most important objectives. Delivering exceptional customer service requires PGE to be responsive to the changing expectations of an evolving customer base. PGE's IRP, 2019 GRC, customer information system, and planned infrastructure investments are part of a strategy focused on providing power supply, distribution reliability, and customer service that meet these expectations.

PGE's investments in a reliable and clean energy future are a key element of the IRP, which will require compliance with statutory renewable standards and consideration of state and local government initiatives to decarbonize the local economy. The Company is also working to advance transportation electrification, with projects to expand and increase access to electric vehicle charging stations and partnering with local mass transit agencies to transition to a greater use of electric vehicles.

Reducing carbon emissions also involves using less energy. PGE helps customers make smart choices by using energy efficient appliances, lights, thermostats and more.

Building a smarter, more resilient grid is essential to affordably delivering the clean energy future that customers want. This requires embracing new technologies, modernizing the Company's existing infrastructure, and implementing a new customer information system to create a foundation to integrate emerging technologies. PGE's capital requirements contemplate the impact of making investments in new, renewable resource generation and energy storage facilities, as well as improvements to its transmission, distribution, and information technology infrastructure.

In 2007, the Oregon State Legislature set a goal to achieve GHG levels that are at least 75 percent below 1990 levels by 2050. Recent GHG policy proposals suggest a new goal of at least 80 percent below 1990 levels by 2050. Additionally, Oregon's Clean Electricity and Coal Transition Plan, enacted in 2016, 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 by 2035. Local governments are also enacting clean energy policy goals.

In June 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, including the cities of Milwaukie and Hillsboro, are considering similar goals. These commitments reflect the values held by customers.

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

Integrated Resource Plans—PGE's 2016 IRP addressed acquisition of additional resources to meet RPS requirements and replace energy and capacity from Boardman, which will cease coal-fired operations at the end of 2020. Further actions identified through 2021 are expected to help integrate variable energy resources, such as wind or solar resources. The 2016 IRP is available on PGE's website.

The 2016 IRP also considered the effects of SB 1547, which, among other things, increased the RPS requirements for 2025 and future years. For further information on SB 1547, see the *"Legal, Regulatory, and Environmental"* section of the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

In August 2017, the OPUC acknowledged PGE's 2016 IRP, an action that allowed the Company to, among other things, finalize agreements to purchase additional annual and seasonal capacity as well as pursue renewable energy and energy storage as described in the paragraphs that follow.

Renewable Energy—The OPUC, in its August 2017 acknowledgement, asked the Company to work with OPUC staff and parties to prepare and submit a revised proposal for acquiring renewable resources. In November 2017, PGE submitted to the OPUC an addendum to the 2016 IRP that included a request for the issuance of an RFP for RPS compliant renewable resources.

In December 2017, the OPUC acknowledged the addendum and, as a result, in May 2018, the Company issued the RFP seeking to procure approximately 100 MWa of qualifying renewable resources.

With the oversight by an independent evaluator selected by the OPUC to help conduct the RFP and review bids to ensure a fair and transparent process, the Company determined a Final Shortlist of proposals. PGE submitted a benchmark project into the RFP process that included a wind resource that would qualify for federal production tax credits. The benchmark project was considered along with other renewable resource proposals and was among the bids included in the Final Shortlist.

The proposals provided various combinations of wind, solar, and battery storage options that included power purchase agreements (PPAs) along with up to 100 MW of Company-owned wind resources. The OPUC acknowledged the RFP Final Shortlist and PGE immediately commenced negotiations with the bidders.

As a result of those negotiations, PGE and NextEra Energy Resources, LLC, a subsidiary of NextEra Energy, Inc. have announced plans to construct a new energy facility in eastern Oregon combining 300 megawatts (MW) of wind generation with 50 MW of solar generation and 30 MW of battery storage.

The new project, called the Wheatridge Renewable Energy Facility, will consist of 120 wind turbines manufactured by GE Renewable Energy, Inc. PGE will own 100 MW of the wind resource with an investment of approximately $160 million. Subsidiaries of NextEra Energy Resources, LLC plan to build and operate the facility and will own the balance of wind resource, along with the solar and battery components, and sell their portion of the output to PGE under 30-year PPAs.

The wind component of the facility is expected to be operational by December 2020 and qualify for federal production tax credits at the 100 percent level. Construction of the solar and battery components is planned for 2021 and is expected to qualify for federal investment tax credits. Any tax credits will help reduce the cost of the project and thus reduce costs to PGE's customers.

The agreements signed by PGE and subsidiaries of NextEra Energy Resources, LLC will be subject to prudency review on customers' behalf by the OPUC. The agreements are also subject to approval by senior management of NextEra Energy, Inc., which is anticipated in March 2019.

Additional information regarding the RFP (OPUC Docket UM 1934) is available on the OPUC website at www.oregon.gov/puc.

Energy Storage—Pursuant to OPUC acknowledgment of the 2016 IRP, PGE filed an energy storage proposal in November 2017 with the OPUC. The proposal 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.

IRP Update—In March 2018, PGE filed an update to its 2016 IRP with the OPUC. The OPUC acknowledged the IRP Update at its April 24, 2018 meeting, and, as a result, PGE included the resource and financial parameters in its May 1, 2018 annual avoided cost update filing.

Since 2016, the Company has experienced significant growth in contract requests from QFs, which, when and if brought to completion, may offset a portion of the capacity currently provided by Boardman. Reliance on QF requests to provide future capacity introduces risk to the Company in its planning process, as the QFs may never come on line, which ultimately influences the amount of capacity and renewables PGE may actually need to procure.

PGE continues to see a trend in which QF contracts are executed and subsequently packaged and sold to large, sophisticated multi-national developers in an effort to take advantage of contract rates that are significantly higher than current market rates. PGE continues to work with the OPUC and stakeholders to evaluate Oregon's implementation of the QF contracting process to promote alignment with RPS targets and decarbonization policy and to ensure customers receive reasonably-priced and reliable renewable energy, while continuing to comply with legal requirements.

As part of the IRP Update filing, PGE's capacity need has been updated to reflect the recently executed bilateral capacity contracts, changes to load forecast, and additional executed QF contracts. The Company expects that the anticipated procurement of resources through the Renewable RFP and energy storage will contribute to meeting the forecasted need identified in the 2016 IRP.

2019 IRP—In preparation for its 2019 IRP, PGE conducted an informal public process throughout the past year. The Company has presented multiple enabling studies to support the 2019 IRP, including a:

- Decarbonization Study evaluating the potential impacts of reducing economy-wide GHG emissions in the PGE service area by 80% by 2050;
- Market Capacity Study evaluating the potential for shifting regional loads and resources to impact the availability of market capacity in the Pacific Northwest over time;
- Distributed Resource and Flexible Load Study, which provided a holistic view of potential Distributed Energy Resource adoption, electric vehicle adoption, and demand response and flexible load program participation among PGE customers; and
- Supply-Side Option Study that provided costs and performance characteristics for supply-side renewables, storage, and thermal resources.

PGE is using the results of the studies and continuing to engage stakeholders in the informal public process to shape the 2019 IRP along with a proposed action plan, which the Company expects to file with the OPUC in the summer of 2019.

General Rate Cases—On February 15, 2018, PGE filed with the OPUC a general rate case based on a 2019 test year (2019 GRC). The filing seeks recovery of costs related to better serving customers and building a smarter, more resilient system and includes the expectation of higher net variable power costs in 2019.

On December 14, 2018, the OPUC issued an order (Order) that, when combined with customer credits and the effects of tax reform, would result in an overall annual increase in PGE's annual revenues of $9 million, resulting in a 0.5% increase in customer prices, to become effective January 1, 2019. In addition, the Order 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 Order provided for the use of a trended weather input assumption to reflect normal conditions in the load forecasting models, which the Company sought, although it did not grant the request for full volumetric decoupling that would include the effects of weather, nor the changes to the storm recovery mechanism.

Primary elements of the 2019 GRC include cost recovery for:

- A new customer information system to provide better, more secure service;
- Replacement and upgrades to equipment to ensure system safety and reliability;
- Equipping substations with technology to address potential outages and shorten those that do occur;
- Strengthening safeguards that protect against cyber attacks and other potential threats; and
- Adding infrastructure to support rapid growth in the region.

On January 1, 2018, new customer prices went into effect pursuant to the OPUC order issued on PGE's 2018 GRC, which was based on a 2018 test year and included recovery of costs related to upgrades to PGE's transmission and distribution system, investments in strengthening and safeguarding the grid, and base business costs. The OPUC authorized a $16 million increase in annual revenues, representing an approximate 1% overall increase in customer prices. In addition, the order approved a capital structure of 50% debt and 50% equity, return on equity of 9.50%, cost of capital of 7.35%, and rate base of $4.5 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.

Tax Reform—On December 22, 2017, the TCJA was enacted into law with substantially all of the provisions of the TCJA 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%.

As a result of the change in corporate tax rate, PGE expected to incur lower income tax expense throughout 2018 than what was estimated in setting customer prices in the Company's 2018 GRC. PGE proposed in a filing with the OPUC on December 29, 2017, to track and defer tax savings as a result of the TCJA and work with the OPUC to determine strategies to provide customers the appropriate benefit.

On December 4, 2018, PGE received OPUC approval to refund a total of $45 million to customers for the 2017-2018 net benefits associated with the TCJA. The refund began amortizing in customer prices on January 1, 2019 over two years. The refund settlement amount was recorded as a reduction to Revenues, net in the consolidated statements of income.

In 2018, PGE, and other individual public utilities received a show cause order from the FERC to justify why the Company's current transmission rates have remained just and reasonable in light of the TCJA and its reduction of corporate taxes. PGE responded to the show cause order and asked FERC to hold in abeyance their show cause proceeding pending PGE's analysis of its transmission rates, which the Company pledged to complete after the finalization of its FERC Form 1 filing. The FERC granted PGE's request for a stay.

Capital Requirements and Financing—PGE's capital requirements amounted to $606 million for 2018, with $26 million related to the customer information system, excluding AFDC. The remainder of the 2018 capital requirements related to a non-utility capital purchase of PGE's corporate headquarters, ongoing capital expenditures for the upgrade, replacement, and expansion of transmission, distribution, and generation infrastructure, as well as technology enhancements and expenditures related to hydro licensing and construction. During 2018, PGE funded its capital requirements through a combination of cash from operations in the amount of $630 million, the $130 million cash proceeds from the settlement of the Carty matter, and proceeds from the issuance of FMBs in the amount of $75 million. Due to the upcoming repayment of long-term debt in 2019, $300 million was classified as current on the Company's consolidated balance sheets as of December 31, 2018.

Capital requirements in 2019 are expected to be $580 million. PGE plans to fund the 2019 capital requirements with cash from operations during 2019, which is expected to range from $550 million to $600 million, the issuance of debt securities of up to $375 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 further information, see the "*Liquidity*" and the "*Debt and Equity Financings*" sections of this Item 7.

Operating Activities—PGE, as a vertically-integrated electric utility, engages in the generation, transmission, distribution, and sale of electricity to retail customers within in its approved service territory in the State of Oregon. In addition, the Company purchases and sells electricity in the wholesale market to meet its retail load requirements and balance its energy supply with customer demand. In 2017, the Company began participation in the California Independent System Operator's Energy Imbalance Market (western EIM), which allows the Company to integrate more renewable energy into the grid by better matching the variable output of renewable resources. 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. The Company generates revenues and cash flows primarily from the sale and distribution of electricity to its retail customers.

The impact of seasonal weather conditions on demand for electricity can cause the Company's revenues, cash flows, and income from operations to fluctuate from period to period. Historically, PGE has been a winter-peaking utility that typically experiences its highest retail energy demand during the winter heating season. Increased use of air conditioning in the Company's service territory; however, has caused the summer peaks to increase in recent years and the long-term load forecasts indicate summer peaks will exceed winter peaks. PGE's all-time summer peak load occurred during August 2017 while the all-time winter peak load was experienced in December 1998. Retail customer price changes and usage patterns, which can be affected by the economy, also have an impact on revenues while wholesale power availability and price, hydro and wind generation, and fuel costs for thermal plants can also affect income from operations.

Customers and Demand—In 2018, retail energy deliveries decreased 2.5% from 2017. Residential customer deliveries which are most sensitive to fluctuations in weather, and commercial customer deliveries contributed to the decrease, while the industrial customer deliveries increased. For 2018 and 2017, the average number of retail customers and deliveries, by customer type, were as follows:

	2018		2017		Increase/ (Decrease) in Energy Deliveries
	Average Number of Customers	**Energy Deliveries ***	**Average Number of Customers**	**Energy Deliveries ***	
Residential	772,389	7,416	762,211	7,880	(5.9)%
Commercial (PGE sales only)	108,570	6,783	107,364	6,932	(2.2)%
Direct Access	537	647	491	623	3.9 %
Total Commercial	109,107	7,430	107,855	7,555	(1.7)%
Industrial (PGE sales only)	203	2,987	199	2,943	1.5 %
Direct Access	67	1,389	68	1,340	3.7 %
Total Industrial	270	4,376	267	4,283	2.2 %
Total (PGE sales only)	881,162	17,186	869,774	17,755	(3.2)%
Total Direct Access	604	2,036	559	1,963	3.7 %
Total	881,766	19,222	870,333	19,718	(2.5)%

* In thousands of MWh.

In 2018, heating degree-days, an indication of electricity use for heating, were 10% below the 15-year average and 19% lower than 2017. Although heating degree-days in the first quarter of 2017 were unusually high, heating degree days each quarter of 2018 were below those of the comparable quarter of 2017. Cooling degree-days, a similar indication of the extent to which customers are likely to have used electricity for cooling, although just 1% below the 2017 level, were 35% above the 15-year moving average.

Residential energy deliveries were 5.9% lower in 2018 than 2017 due largely to the effects of warmer temperatures during the winter season and a continued trend of lower use per customer, despite residential average customer growth of 1.3%. See *"Revenues"* in the 2018 Compared to 2017 section of Results of Operations within this Item 7, for further information on heating and cooling degree days.

Commercial deliveries also decreased by 1.7% largely as a result of less favorable weather conditions. Deliveries to several retail sectors decreased, including food and merchandise stores and health care, while other service sectors, including data centers, showed growth. Energy efficiency programs and efforts continues to impact growth and are likely reducing energy deliveries.

The 2.2% increase in industrial energy deliveries is due to continued increases in energy deliveries to the high-tech manufacturing sector. This increase resulted even though the Company experienced the closure of a large paper customer in October 2017, which reduced comparative deliveries in 2018.

On a weather-adjusted basis, total retail deliveries increased 0.4% from 2017 reflecting a 0.2% increase in residential deliveries, as growth in average number of customers was mostly offset by a decline in the average usage per customer, a decline of 0.4% in commercial deliveries and a 2.4% increase in industrial deliveries driven primarily by strength in the high-tech manufacturing sector.

ESSs supplied Direct Access customers with energy representing 11% of the Company's total retail energy deliveries during 2018 and 10% for 2017. 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 2018, and 13% in 2017.

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 through 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 *"Legal, Regulatory, and Environmental"* in this Overview section of Item 7, for further information on the decoupling mechanism.

In 2018, PGE recorded an estimated collection of $2 million under the mechanism as weather-adjusted energy use per customer was less than that estimated and approved in the Company's 2018 GRC. A final determination of the 2018 amount will be made by the OPUC through a public filing and review in 2019. Any resulting collection from customers is expected to begin January 1, 2020. The $11 million estimated collection deferred in the 2017 year began January 1, 2019. For 2016, amortization of the $3 million collection amount occurred in 2018 following a final determination of the amount by the OPUC.

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. 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.

Plant availability is impacted by planned maintenance and forced, or unplanned, outages, during which the respective plant is unavailable to provide power. PGE's thermal generating plants require varying levels of annual maintenance, which is generally performed during the second quarter of the year. Availability of all the plants PGE operates approximated 93% for the year ended December 31, 2018, 90% for 2017, and 93% for 2016, with the availability of Colstrip, which PGE does not operate, approximating 82%, 86%, and 85% for the years ended December 31, 2018, 2017, and 2016, respectively. During the year ended December 31, 2018, the Company's generating plants provided approximately 76% of its retail load requirement compared to 69% in 2017 and 70% in 2016.

Energy received from PGE-owned hydroelectric plants and under contracts from mid-Columbia hydroelectric projects decreased 10% in 2018 compared to 2017, due to less favorable hydro conditions in 2018. These resources provided 17% of the Company's retail load requirement for 2018, compared with 18% for 2017 and 17% for 2016. Energy received from these sources fell below projected levels included in PGE's AUT by 4% in 2018, exceeded projected levels included in the Company's AUT by 6% in 2017, and did not materially differ from the projections in 2016. Such projections, which are finalized with the OPUC in November each year, establish the power cost component of retail prices for the following calendar year. Normal hydroelectric conditions represent the level of energy forecasted to be received from hydroelectric resources for the year and is based on average regional hydro conditions over a recent 30-year period. Any shortfall is generally replaced with power from higher cost sources, while any excess in hydro generation from that projected in the AUT generally displaces power from higher cost sources. See *"Purchased power and fuel"* in the 2018 Compared to 2017 section of Results of Operations in this Item 7, for further detail on regional hydro results.

Energy expected to be received from wind generating resources (Biglow Canyon and Tucannon River) is projected annually in the AUT based on historical generation. Any excess in wind generation from that projected in the AUT generally displaces power from higher-cost sources, while any shortfall is generally replaced with power from higher-cost sources. Energy received from wind generating resources fell short of that projected in PGE's AUT by 5% in 2018, 18% in 2017, and 7% in 2016. 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, production tax credits 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 2018, 2017, and 2016:

- 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 will be made by the OPUC through a public filing and review in 2019.
- For 2017, actual NVPC was above baseline NVPC by $15 million, which was within the established deadband range. Accordingly, no estimated collection from customers was recorded as of December 31, 2017. A final determination regarding the 2017 PCAM results was made by the OPUC through a public filing and review in 2018, which confirmed no collection from customers pursuant to the PCAM for 2017.
- For 2016, actual NVPC was below baseline NVPC by $10 million, which was within the established deadband range. Accordingly, no estimated refund to customers was recorded as of December 31, 2016. A final determination regarding the 2016 PCAM results was made by the OPUC through a public filing and review in 2017, which confirmed no refund to customers pursuant to the PCAM for 2016.

Western EIM—The Company's participation in the western EIM began October 1, 2017. As a market participant in the western EIM, PGE allows certain of its generating plants to receive automated dispatch signals from the CAISO that allows for load balancing with other western EIM participants in five-minute intervals. The Company expects such load balancing will help integrate more renewable energy into the grid by better matching the variable output of renewable resources. Shortly after the entry into the western EIM, PGE began to self-integrate its Company-owned wind generation. Additionally, participation in the western EIM gives PGE access to the lowest-cost energy available in the region to meet changes in real-time energy loads and short-term variations in customer demand.

Gas Storage—PGE has contractual access to natural gas storage in Mist, Oregon from which it can draw in the event that natural gas supplies are interrupted or if economic factors require its use. The storage facility is owned and operated by a local natural gas company, NW Natural, and may be utilized to provide fuel to PGE's Port Westward Unit 1 and Beaver natural gas-fired generating plants and the Port Westward Unit 2 natural gas-fired flexible capacity generating plant. PGE has entered into a long-term agreement with this gas company to expand the current storage facilities, including the construction of a new reservoir, compressor station, and 13-miles of pipeline, which will collectively be designed to provide no-notice storage services to these PGE generating plants. NW Natural estimates construction will be completed in the spring of 2019, at a cost of approximately $144 million. Due to the level of PGE's involvement during the construction period, the Company is deemed to be the owner of the assets for accounting purposes during the construction period. As a result, PGE has recorded $131 million to construction work-in-progress (CWIP) and a corresponding liability for the same amount to Other noncurrent liabilities in the consolidated balance sheets as of December 31, 2018. See Note 2, Summary of Significant Accounting Policies in Item 8. - "Financial Statements and Supplementary Data" for lease considerations of this agreement.

Legal, Regulatory, and Environmental Matters—PGE is a party to certain proceedings, the ultimate outcome of which could have a material impact on the Company's results of operations and cash flows in future reporting periods. Such proceedings include, but are not limited to, the ongoing environmental investigation of Portland Harbor.

Clean Power Plan—In August 2015, the EPA released the CPP, under which each state would have to reduce the carbon intensity of its power sector on a state-wide basis by a specified amount. In February 2016, the United States

Supreme Court granted a stay, halting implementation and enforcement of the CPP, pending the resolution of legal challenges to the rule. In October 2017, the EPA published a proposed rule in which it outlined a rationale for repealing the CPP. The public comment period for the repeal rule closed April 26, 2018.

On August 21, 2018, the EPA proposed the ACE rule, which would replace the CPP and establish emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired plants. The public comment period on the proposed ACE rule closed on October 31, 2018. The EPA has yet to finalize either rulemaking.

The Company continues to monitor the developments around the CPP legal challenges and the potential new rule. The Company cannot predict the ultimate outcome of the legal challenges and the regulatory process of the EPA, or whether the states in which the Company's thermal generation facilities are located (Oregon and Montana) will implement the rule or how the rule may impact the Company's operations.

Senate Bill 1547—The State of Oregon passed, effective in March 2016, a law referred to as the Oregon Clean Electricity and Coal Transition Plan (SB 1547). The legislation will impact PGE in several ways, one of which is to prevent the Company from including the costs and benefits associated with coal-fired generation in its Oregon retail rates after 2030 (subject to an exception that extends this date until 2035 for PGE's output from Colstrip). As a result, in October 2016, the Company filed a tariff request, which the OPUC approved, to incorporate in customer prices, on January 1, 2017, the approximate $6 million annual effect of accelerating recovery of PGE's investment in Colstrip from 2042 to 2030, as required under the legislation.

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 on line before December 31, 2022; and
- An allowance for energy storage costs related to renewable energy in the Company's RAC filings.

The Company has evaluated the potential impacts and incorporated the effects of the legislation into its 2016 IRP.

Oregon Legislative Initiatives—The State of Oregon legislators proposed Senate Bill 1070, which was referred to as the Clean Energy Jobs Bill, during the abbreviated 35-day legislative session in 2018, in an effort to reduce greenhouse gas emissions that contribute to climate change through a statewide cap and trade program. Although such legislation did not emerge from the 2018 legislative session, a new, similar proposal called the Oregon Climate Action Program, House Bill 2020, was introduced in 2019 legislative session that began in January 2019. As initially proposed, the legislation would, among other things:

- Modify statewide greenhouse gas emissions reduction goals;
- Require a program to place a cap on greenhouse gas emissions and provide a market-based mechanism for covered entities to demonstrate compliance with program; and
- Authorize the OPUC to allow recovery in customer prices to reflect amounts for programs that enable public utilities to assist low-income residential customers.

The Company is monitoring developments around this proposal that could emerge from the full length 2019 legislative session.

Senate Bill 978—The State of Oregon legislature passed a bill in its 2017 session referred to as SB 978, which directed the OPUC to investigate and provide a report to the legislature on how developing industry trends, technology, and policy drivers in the electricity sector might impact the existing regulatory system and incentives. PGE actively worked on this initiative with both external stakeholders and the OPUC, to provide guidance and support for the report. The OPUC issued the final report to the legislature on September 14, 2018 in which the OPUC committed to four focus areas:

- Exploring performance-based ratemaking and other regulatory tools to align utility incentives with customer goals, industry trends, and statewide goals;
- Cooperating with other states to support and explore development of an organized regional market;
- Developing a strategy for low income and environmental justice groups' engagement and inclusion in OPUC processes that will carry forward beyond the SB 978 proceeding; and
- Improving the Commission's regulatory tools to value system costs and benefits, which enables customer choice and a strong utility system.

The OPUC also stated that it would 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 legislature may address the limitation identified by the OPUC for direct authority to address climate change through expected comprehensive cap and trade legislation during the 2019 legislative session.

Green Tariff—The Company continues to pursue OPUC approval of a proposed green tariff program that would allow business customers to access bundled renewable energy from new resources. Through this proposed tariff, submitted to the OPUC in early 2018, the Company seeks to align sustainability goals, cost and risk management, reliable integrated power, and a cleaner energy system. PGE proposes to avoid stranded costs and cost shifting by having subscribers continue under the Company's existing cost of service tariff, with the green tariff added, and procuring competitive, renewable energy through the use of power purchase agreements or additional renewable generation. PGE expects an OPUC decision in early 2019.

Other Regulatory Matters—The following discussion highlights certain regulatory items that have impacted the Company's revenues, results of operations, or cash flows for 2018 compared with 2017, have affected retail customer prices, or may in the future, as authorized by the OPUC. In some cases, the Company has deferred the related expenses or benefits as regulatory assets or liabilities, respectively, for later amortization and inclusion in customer prices, pending OPUC review and authorization.

Power Costs—Pursuant to the AUT process, PGE files annually an estimate of power costs for the following year. In the event a general rate case is filed in any given year, forecasted power costs would be included in such filing. Such forecast assumes the following for the different types of PGE-owned generating resources:

- Thermal—Expected operating conditions;
- Hydroelectric—Regional hydro generation based on historical stream flow data and current hydro operating parameters; and
- Wind—Generation levels based on a five-year historical rolling average of the wind farm. To the extent historical information is not available for a given year, the projections are based on wind generation studies.

For further information, see *"Power Operations"* in the Operating Activities section of this Overview, above.

As part of its 2019 GRC, PGE included an initial projected increase in power costs of $39 million that was included in the overall request submitted to the OPUC. 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.

As part of its 2018 GRC, PGE included an initial projected reduction in power costs of $29 million that was included in the overall request submitted to the OPUC. As approved by the OPUC in December 2017, the

2018 GRC included a final projected reduction in power costs for 2018 and a corresponding reduction in annual revenue requirement, of $47 million from 2017 levels.

The 2017 AUT filing, approved by the OPUC in November 2016 and included in customer prices effective January 1, 2017, projected a reduction in power costs for 2017, and a corresponding reduction in annual revenue requirement, of $56 million from 2016 levels. Actual NVPC for 2017, as calculated for regulatory purposes under the PCAM, was $15 million above the 2017 baseline NVPC.

Renewable Resource Costs—Pursuant to the RAC mechanism, PGE can recover in customer prices prudently incurred costs of renewable resources. In the 2019 GRC Order, the OPUC authorized the inclusion of prudent costs of energy storage projects associated with renewables in future RAC filings, under certain conditions. The Company may submit a filing to the OPUC by April 1 each year. No significant filings have been submitted under the RAC during 2018, 2017, or 2016.

Decoupling Mechanism—The decoupling mechanism, which the OPUC has now extended 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 $2 million during the year ended December 31, 2018, which resulted from variances between actual weather-adjusted use per customer and that projected in the 2018 GRC. Collections under the decoupling mechanism are subject to an annual limitation of 2% of the applicable rate schedule, which was $18 million for 2018. Any collection from customers, as approved, for the 2018 year is expected to occur over a one-year period, which would begin January 1, 2020.

The Company recorded a deferral for an estimated collection of $11 million during the year ended December 31, 2017, as a result of variances from amounts established in the 2016 GRC. Collection for the year ended December 31, 2017 will occur over a one-year period, which began January 1, 2019.

The $3 million collection recorded in 2016 that resulted from variances between actual weather adjusted use per customer and that projected in the 2016 GRC, occurred during 2018. Similarly, a refund of the $9 million recorded during 2015 occurred during 2017.

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. The 2018 GRC, as approved by the OPUC, increased the annual collection amount to $3 million, beginning in 2018. Under the 2019 GRC, the annual collection amount will be increased to $4 million beginning in 2019.

Due to a series of storm events in the first half of 2017, the Company exhausted the $2 million 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 $2 million amount collected in 2017. During 2016, due to excessive storm restoration costs, PGE had exhausted the available reserve at the end of the year.

As a result of the additional costs incurred, PGE filed an application with the OPUC requesting authorization to defer incremental storm restoration costs from the date of the application, in the first quarter of 2017, through the end of 2017, net of the $2 million being collected annually under the methodology at that time. An OPUC decision on the application remains pending. The Company is unable to predict how the OPUC will ultimately rule on this application or state with any certainty whether these incremental costs are probable of recovery and, accordingly, no deferral has been recorded to-date. In the event it becomes probable that some or all of these costs are recoverable, the Company will record a deferral for such amounts at such time. The OPUC, in its decision on the Company's 2019 GRC, directed OPUC Staff to bring this matter before the OPUC within 90 days of the issuance of the decision on the 2019 GRC.

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, 2018, significant uncertainties still remain concerning the precise boundaries for clean-up, the assignment of responsibility for clean-up costs, the final selection of a proposed remedy by the EPA, and the method of allocation of costs amongst PRPs. It is probable that PGE will share in a portion of these costs. However, the Company does not currently have sufficient information to reasonably estimate the amount, or range, of its potential costs for investigation or remediation of Portland Harbor, although such costs could be material to PGE's financial position. However, the impact of such costs to the Company's results of operations is mitigated by the PHERA mechanism. As approved in 2017, 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.

Deferral of Capital Costs—In the second quarter of 2018, PGE placed into service a new customer information system at a total cost of $152 million. Consistent with agreements reached with stakeholders in the Company's 2019 General Rate Case, 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, on May 11, 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 costs, primarily related to depreciation and amortization, of the new customer information system upon it being placed in service.

On November 21, 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. On October 29, 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 has considered its alternatives, and has requested reconsideration and clarification. 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 the nine months ended September 30, 2018, PGE had deferred a total of $7 million related to the project. However, the Order has impacted the probability of recovery of the customer information system deferral and, as such, the Company has recorded a reserve for the full amount of the capital deferral through September 30, 2018 as well as an additional $5 million for the three months ended December 31, 2018. The full amount of the reserve was recognized as a charge to the results of operations in 2018 in the amount of $12 million. 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.

Carty—Pursuant to the final order issued by the OPUC on November 3, 2015 in connection with the Company's 2016 GRC, the Company was authorized to include in customer prices the capital costs for Carty of up to $514 million, as well as Carty's operating costs, effective August 1, 2016, following the placement of the plant into service on July 29, 2016.

As the final construction cost exceeded the amount authorized by the OPUC, PGE's cost of service exceeded what was allowed in the Company's revenue requirement primarily due to higher depreciation and amortization on the incremental capital cost, interest expense, and legal expense. These incremental costs totaled $8 million and $14 million for the years ended December 31, 2018 and 2017, respectively, and is reflected in the Company's results of operations.

On July 16, 2018, the Company entered into a settlement to resolve all claims between the Company and each of Abeinsa EPC LLC, Abener Construction Services, LLC, Teyma Construction USA, LLC, and Abeinsa Abener Teyma General Partnership (collectively, the Contractor), Abengoa S.A., and Liberty Mutual Insurance Company and Zurich American Insurance Company (together, the Sureties). Under the terms of the settlement, i) the Sureties paid $130 million to PGE, and ii) the Contractor, Abengoa S.A., and the Sureties released all claims against the Company arising out of the Carty construction, and in return, PGE released all such claims against the Contractor, Abengoa S.A., and the Sureties, relating to Carty construction. The proceeds fully offset the incremental construction costs, thus eliminating ongoing excess depreciation and amortization, interest expense, and partially offsetting the Company's other accumulated damages.

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

For additional details regarding various legal and regulatory proceedings related to Portland Harbor, Carty, and other matters, see Note 18, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

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,					
	2018		2017		2016	
	Amount	As % of Rev	Amount	As % of Rev	Amount	As % of Rev
Total revenues (1)	$ 1,991	100%	$ 2,009	100%	$ 1,923	100%
Purchased power and fuel (1)	571	30	592	30	617	32
Gross margin	1,420	70	1,417	70	1,306	68
Other operating expenses:						
Generation, transmission and distribution	292	15	309	16	286	15
Administrative and other	271	13	260	13	240	12
Depreciation and amortization	382	19	345	17	321	17
Taxes other than income taxes	129	6	123	6	119	6
Total other operating expenses	1,074	53	1,037	52	966	50
Income from operations	346	17	380	18	340	18
Interest expense, net (2)	124	6	120	6	112	6
Other income:						
Allowance for equity funds used during construction	11	1	12	1	21	1
Miscellaneous income, net	(4)	—	1	—	(6)	—
Other income, net	7	1	13	1	15	1
Income before income taxes	229	12	273	13	243	13
Income tax expense	17	1	86	4	50	3
Net income	$ 212	11%	$ 187	9%	$ 193	10%

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

(2) Includes an allowance for borrowed funds used during construction of $6 million in 2018 and 2017, and $11 million in 2016.

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

	Years Ended December 31,					
	2018		2017		2016	
Revenues[1] (dollars in millions):						
Retail:						
Residential	$ 948	48%	$ 969	48%	$ 907	47%
Commercial	647	32	652	32	652	34
Industrial	185	9	192	10	193	10
Direct Access	43	2	37	2	28	2
Subtotal	1,823	91	1,850	92	1,780	93
Alternative revenue programs, net of amortization	3	—	—	—	—	—
Other accrued (deferred) revenues, net[2]	(45)	(2)	10	1	3	—
Total retail revenues	1,781	89	1,860	93	1,783	93
Wholesale revenues	159	8	105	5	103	5
Other operating revenues	51	3	44	2	37	2
Total revenues	$ 1,991	100%	$ 2,009	100%	$ 1,923	100%
Energy deliveries (MWh in thousands):						
Retail:						
Residential	7,416	31%	7,880	34%	7,348	33%
Commercial	6,783	29	6,932	30	6,932	31
Industrial	2,987	13	2,943	13	2,968	13
Subtotal	17,186	73	17,755	77	17,248	77
Direct access:						
Commercial	647	3	623	3	525	2
Industrial	1,389	6	1,340	6	1,198	6
Subtotal	2,036	9	1,963	9	1,723	8
Total retail energy deliveries	19,222	82	19,718	86	18,971	85
Wholesale energy deliveries	4,290	18	3,193	14	3,352	15
Total energy deliveries	23,512	100%	22,911	100%	22,323	100%
Average number of retail customers:						
Residential	772,389	88%	762,211	88%	752,365	88%
Commercial	108,570	12	107,364	12	106,460	12
Industrial	203	—	199	—	195	—
Direct access	604	—	559	—	376	—
Total	881,766	100%	870,333	100%	859,396	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, $17 million, and $13 million for 2018, 2017, and 2016, respectively. Industrial revenues from ESS customers were $25 million, $20 million, and $15 million for 2018, 2017, and 2016, respectively.

(2) Amount at December 31, 2018 primarily relates to the regulatory liability deferral of the 2018 net tax benefits due to the change in corporate tax rate under the Tax Cuts and Jobs Act of 2018 (TCJA). For further information, see Note 12, Income Taxes in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

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

	Years Ended December 31,					
	2018		2017		2016	
Sources of energy (MWh in thousands):						
Generation:						
Thermal:						
Natural gas	7,515	33%	6,228	28%	5,811	27%
Coal	3,106	14%	3,344	15	3,492	16
Total thermal	10,621	47	9,572	43	9,303	43
Hydro	1,474	7	1,774	8	1,629	8
Wind	1,875	8	1,641	8	1,912	9
Total generation	13,970	62	12,987	59	12,844	60
Purchased power:						
Term	6,714	30	7,192	33	6,961	32
Hydro	1,603	7	1,648	7	1,541	7
Wind	286	1	264	1	301	1
Total purchased power	8,603	38	9,104	41	8,803	40
Total system load	22,573	100%	22,091	100%	21,647	100%
Less: wholesale sales	(4,290)		(3,193)		(3,352)	
Retail load requirement	18,283		18,898		18,295	

Net income for the year ended December 31, 2018 was $212 million, or $2.37 per diluted share, compared with $187 million, or $2.10 per diluted share, for the year ended December 31, 2017. Among the factors that led to the $25 million, or 13%, increase in net income were the following:

- Temperature contrasts contributed to lower energy demand in 2018 as customers used less energy in the warmer 2018 heating season compared with the colder than average 2017 period.
- While retail deliveries were lower in 2018, lower Purchased power and fuel cost contributed to hold Gross margin comparable to 2017, as Wholesale revenues increased.
- The reduction in Generation, transmission and distribution expense reflects the significant storm related costs recorded in 2017 as well as lower plant maintenance expenses in 2018.
- The increase in Administrative and general expenses in 2018 was partially offset by a $14 million expense reduction due to the conclusion of the Carty litigation and cash settlement.
- The increase in Depreciation and amortization largely reflects capital additions, including $8 million higher amortization due to the new customer information system.
- The Company recorded $9 million lower revenues under the decoupling mechanism in 2018 than in 2017.

Net income for the year ended December 31, 2017 was $187 million, or $2.10 per diluted share, compared with $193 million, or $2.16 per diluted share, for the year ended December 31, 2016. The $6 million, or 3%, decrease in net income resulted primarily from the net impact of the following three items: i) Gross margin increased due to higher energy demand, primarily due to weather and strength in the industrial sector; ii) Operating expense increased due to higher depreciation expense as a result of asset base growth, several storms in 2017 that increased restoration expenses, higher administrative and general expenses due to increases in employee count, and additional litigation and interest expense related to Carty; and iii) Income tax expense increased due to higher pre-tax income, the impacts of the TCJA, and lower PTCs.

2018 Compared to 2017

Total revenues decreased $18 million, or 0.9%, in 2018 compared with 2017 as a result of the items discussed below.

Total retail revenues decreased $79 million, or 4.2%, in 2018 compared with 2017, primarily due to the net effect of:

- $47 million reduction resulted from the 2.5% overall decrease in retail energy deliveries consisting of a 5.9% decrease in residential deliveries, and a 1.7% decrease in commercial deliveries, partially offset by a 2.2% increase in industrial deliveries. The effects of weather on electricity demand is reflected predominantly in the Residential revenue line in the table above. Considerably warmer temperatures in the first quarter of 2018 than experienced in 2017, which was colder than average, along with more moderate temperatures in the balance of 2018 than 2017, combined to drive deliveries lower. For further information on customer demand, see *"Customers and Demand"* in the Overview section of this Item 7;
- $45 million decrease to reflect the deferral of revenues for refund to customers as a result of the TCJA, which is reflected in the Other accrued (deferred) revenues, net line in the table above. This reduction in revenues is offset with lower income tax expense; and
- $9 million decrease from the results of the decoupling mechanism, net of amortization, as a $2 million collection from customers was deferred into revenue in 2018, as opposed to a $11 million collection from customers deferred into revenue in 2017; partially offset by
- $14 million increase as a result of the expiration of the credits to customers for the Trojan spent fuel refund, the effect of which is offset in Depreciation and amortization expense; and
- $9 million increase in revenues as a result of price changes, which includes a $47 million reduction in revenues attributable to lower estimated NVPC, as filed in the 2018 GRC.

Total heating degree-days in 2018 were below the 15-year average and down considerably from total heating degree-days in 2017. Total cooling degree-days in 2018 exceeded the 15-year average by 35% and were comparable to the 2017 total. The following table presents the number of heating and cooling degree-days in 2018 and 2017, along with the 15-year averages, reflecting that weather had a considerable influence on comparative energy deliveries:

	Heating Degree-Days			**Cooling Degree-Days**		
	2018	**2017**	**15-Year Average**	**2018**	**2017**	**15-Year Average**
1st quarter	1,766	2,171	1,813	—	—	—
2nd quarter	471	686	656	116	129	85
3rd quarter	69	78	75	575	571	426
4th quarter	1,396	1,623	1,573	1	—	3
Total	3,702	4,558	4,117	692	700	514
Increase (decrease) from the 15-year average	(10)%	11%		35%	36%	

On a weather-adjusted basis, total retail energy deliveries in 2018 increased 0.4% from 2017 levels. PGE projects that retail energy deliveries for 2019 will be nearly comparable to slightly above 2018 weather-adjusted levels, reflecting strength in industrial deliveries, partially offset by continued energy efficiency and conservation efforts.

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 2018, the $54 million, or 51%, increase in wholesale revenues over 2017 resulted from $36 million related to a 34% increase in wholesale sales volume combined with $18 million from a 13% increase in average prices received when the Company sold power into the wholesale market.

Other operating revenues increased $7 million, or 16%, in 2018 from 2017, approximately half of which was attributable to the sale of excess natural gas not used to fuel the Company's generating facilities, and a $2 million increase from the Company's transmission revenue sales.

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 2018, Purchased power and fuel expense decreased $21 million, or 4%, from 2017, which was driven by a $24 million decrease that resulted from a lower average variable power cost per MWh and a $3 million increase related to total system load.

The $24 million decrease related to average variable power is due to a decrease in cost per MWh from $26.80 in 2017 to $25.31 per MWh in 2018. The price decrease was driven primarily by a 16% reduction in the average variable power cost per MWh from PGE generating resources. This was partially offset by an 8% increase in the average variable power cost per MWh for purchased power as the Company, on average, purchased power at higher market prices.

The $3 million increase due to total system load was driven primarily by a 34% increase in wholesale deliveries, partially offset by lower retail energy deliveries. Energy obtained from the Company's natural gas-fired resources increased 21% when compared to 2017, however this was partially offset by a 17% decrease in energy obtained from the Company's hydro resources due to less favorable hydro conditions.

In 2018, energy received from Biglow Canyon and Tucannon River increased 14% from 2017 due to more favorable wind conditions and provided 10% of the Company's retail load requirement in 2018 compared with 9% in 2017.

As a result of the less favorable hydro conditions in the region for 2018, energy received from PGE-owned hydroelectric projects in combination with mid-Columbia projects was 10% below 2017 levels and represented 17% of the Company's retail load requirement for 2018 compared with 18% for 2017.

The following table presents the actual April-to-September 2018 and 2017 runoff at particular points of major rivers relevant to PGE's hydro resources:

	Runoff as a Percent of 30-year Average	
Location	**2018 Actual**	**2017 Actual**
Columbia River at The Dalles, Oregon	98%	98%
Mid-Columbia River at Grand Coulee, Washington	99	98
Clackamas River at Estacada, Oregon	97	97
Deschutes River at Moody, Oregon	96	98

Actual NVPC, which consists of Purchased power and fuel expense net of Wholesale revenues, decreased $75 million in 2018 compared with 2017. The decrease attributable to changes in Purchased power and fuel expense was the result of a 6% decline in the average variable power cost per MWh, offset slightly by a 2% increase in total system load. The decrease in actual NVPC was also driven by a 34% increase in the volume of wholesale energy deliveries, that were sold, on average, at 13% higher average price per MWh.

For 2018, actual NVPC, as calculated for regulatory purposes under the PCAM, was $3 million below the 2018 baseline NVPC. In 2017, NVPC was $15 million above the anticipated baseline. For further information regarding NVPC, see *"Power Operations"* in the Overview section of this Item 7.

Generation, transmission, and distribution expense decreased $17 million, or 6%, in 2018 compared with 2017. The decrease was driven by the combination of $13 million in lower storm costs and $7 million lower plant maintenance expenses.

Administrative and other expense increased $11 million, or 4%, in 2018 compared with 2017, primarily due to $12 million higher overall labor and employee benefit expenses and $8 million higher expense due to an increase in the reserve for light and power receivables, offset by a $10 million expense reduction for the Carty cash settlement, and $4 million lower legal expenses attributable to the conclusion of litigation around Carty construction.

Depreciation and amortization expense in 2018 increased $37 million, or 11%, compared with 2017. The increase was primarily driven by $17 million less expense in 2017 due to credits for the amortization of the regulatory liability provided to customers for the ISFSI spent fuel settlement, $10 million higher expense in 2018 resulting from capital additions, $8 million higher amortization due to the new customer information system in 2018, and a $4 million increase to asset retirement obligations.

Taxes other than income taxes expense increased $6 million, or 5%, in 2018 compared with 2017, driven by $3 million higher Oregon property taxes and $2 million higher franchise fees.

Interest expense increased $4 million, or 3%, in 2018 compared with 2017 due to higher expense as a result of a 2.7% increase in the average balance of debt outstanding.

Other income, net was $7 million in 2018 compared to $13 million in 2017, primarily due to losses on the non-qualified employee benefit trust.

Income tax expense decreased $69 million, or 80%, in 2018 compared to 2017. The decrease was driven by a lower federal corporate tax rate and other items pursuant to the TCJA, excess deferred tax amortization, lower pre-tax income and a 2017 remeasurement of deferred taxes. The reduction in expense driven by the TCJA is offset by $45 million that will be refunded to customers, and was recorded as a reduction to Revenues, net in the Consolidated Statements of Income.

2017 Compared to 2016

Revenues increased $86 million, or 4.5%, in 2017 compared with 2016 as a result of the items discussed below.

Total retail revenues increased $77 million, or 4.3%, in 2017 compared with 2016, primarily due to the net effect of:

- A $71 million increase due to a 3.9% increase in retail energy deliveries consisting of a 7.2% increase in residential deliveries, a 2.8% increase in industrial deliveries, and a 1.3% increase in commercial deliveries. Considerably cooler temperatures in the first half of 2017 than experienced in 2016 combined with warmer temperatures in the summer cooling season in 2017, both drove deliveries higher in 2017 than in 2016. For further information on customer demand, see *"Customers and Demand"* in the Overview section of this Item 7;
- A $10 million increase resulting from the decoupling mechanism, net of amortization as an estimated $11 million collection was deferred into revenue in 2017; and
- A $5 million increase, directly offset in Depreciation and amortization expense, related to the accelerated cost recovery of Colstrip, partially offset by
- A $5 million reduction as a result of overall price changes, which includes a $55 million reduction in revenues attributable to lower NVPC, as filed in the 2017 AUT; and

- A $3 million decrease due to higher customer credits related to the USDOE settlement in connection with operation of the ISFSI at the former Trojan nuclear power plant site. Such credits are directly offset in Depreciation and amortization expense.

Total heating degree-days in 2017 were above the 15-year average and considerably greater than total heating degree-days in 2016. Total cooling degree-days in 2017 exceeded the 15-year average by 49% and were considerably higher than 2016. The following table presents the number of heating and cooling degree-days in 2017 and 2016, along with the 15-year averages, reflecting that weather had a considerable influence on comparative energy deliveries:

	Heating Degree-Days			Cooling Degree-Days		
	2017	2016	15-Year Average	2017	2016	15-Year Average
1st quarter	2,171	1,585	1,866	—	—	—
2nd quarter	686	403	689	129	154	70
3rd quarter	78	78	78	571	394	399
4th quarter	1,623	1,486	1,600	—	—	2
Total	4,558	3,552	4,233	700	548	471
Increase (decrease) from the 15-year average	8%	(16)%		49%	16%	

On a weather-adjusted basis, total retail energy deliveries in 2017 were 0.6% below 2016 levels. PGE projected that retail energy deliveries for 2018 would be nearly comparable to slightly lower than 2017 weather-adjusted levels, reflecting the closure of a large paper customer in late 2017 as well as continued energy efficiency and conservation efforts.

Wholesale revenues in 2017 increased $2 million, or 2%, from 2016, with such increase consisting of a $7 million increase that resulted from a 7% increase in average prices received when the Company sold power into the wholesale market, partially offset by a $5 million decrease related to 5% less wholesale sales volume.

Other operating revenues increased $7 million, or 19%, in 2017 from 2016, as the sale of excess natural gas not used to fuel the Company's generating facilities accounted for the majority of the increase.

Purchased power and fuel expense in 2017 decreased $25 million, or 4%, from 2016, driven by a $38 million, or 6%, decline related to the decrease in the average variable power cost per MWh to $26.80 in 2017 from $28.50 in 2016, partially offset by a $13 million increase resulting from a 2% increase in total system load.

The decrease related to average variable power cost per MWh was driven primarily by: i) a 7% reduction in the average variable power cost per MWh for purchased power as the Company, on average, purchased power at lower market prices; and ii) a 13% reduction in the average variable power cost per MWh related to energy received from the Company's natural gas-fired resources due to lower natural gas prices. This was partially offset by the purchase of replacement power due to 14% less energy received from the Company's wind generating resources.

In 2017, energy received from Biglow Canyon and Tucannon River decreased 14% from 2016 due to less favorable wind conditions and provided 9% of the Company's retail load requirement in 2017 compared with 10% in 2016. As a result of improved hydro conditions in the region during 2017, energy received from PGE-owned hydroelectric projects, in combination with mid-Columbia projects, was 8% above 2016 levels and represented 18% of the Company's retail load requirement for 2017 compared with 17% for 2016.

The following table presents the actual of the April-to-September runoff for 2017 and 2016:

Location	Runoff as a Percent of 30-year Average 2017 Actual	2016 Actual
Columbia River at The Dalles, Oregon	98%	89%
Mid-Columbia River at Grand Coulee, Washington	98	91
Clackamas River at Estacada, Oregon	97	71
Deschutes River at Moody, Oregon	98	91

Actual NVPC decreased $27 million for 2017 compared with 2016. The decrease attributable to changes in Purchased power and fuel expense was the result of an 6% decline in the average variable power cost per MWh, offset slightly by a 2% increase in total system load. The decrease in actual NVPC was also driven by a 7% increase in the average price per MWh of wholesale power sales, offset slightly by a 5% decrease in the volume of wholesale energy deliveries as the Company's retail load requirement increased in 2017, largely due to the effects of weather, which resulted in a greater portion of its system load used to meet retail load requirements.

For 2017, actual NVPC, as calculated for regulatory purposes under the PCAM, was $15 million above the 2017 baseline NVPC, compared with $10 million below the anticipated baseline for 2016.

Generation, transmission, and distribution expense increased $23 million, or 8%, in 2017 compared with 2016. The increase was driven by the combination of $10 million in higher costs due to the addition of Carty, $8 million higher service restoration and storm costs, $3 million higher plant maintenance expenses, and $2 million higher information technology expenses.

Administrative and other expense increased $20 million, or 8%, in 2017 compared with 2016, primarily due to $12 million higher overall labor and employee benefit expenses, $3 million higher legal costs attributable to Carty and a $3 million difference in the non-service cost component of net periodic pension expense reclassified as a result of the adoption of ASU 2017-07, see Note 2, Summary of Significant Accounting Policies in Item 8. - "Financial Statements and Supplementary Data".

Depreciation and amortization expense in 2017 increased $24 million, or 7%, compared with 2016. The increase was primarily driven by $26 million higher expense resulting from capital additions, partially offset by a $3 million reduction in expense due to higher amortization credits in 2017 of the regulatory liability for the ISFSI spent fuel settlement. The overall impact resulting from the amortization of the regulatory assets and liabilities is directly offset by corresponding reductions in retail revenues.

Taxes other than income taxes expense increased $4 million, or 3%, in 2017 compared with 2016, driven by $2 million higher Oregon property taxes and $2 million higher payroll taxes.

Interest expense increased $8 million, or 7%, in 2017 compared with 2016 as a result of a $4 million decrease in the credits for the allowance for borrowed funds used during construction (primarily due to the Carty plant being placed in service in 2016) and an increase of $3 million resulting from a 5% larger average balance of debt outstanding.

Other income, net was $13 million in 2017 compared with $15 million in 2016, with the decrease primarily due to lower allowance for equity funds used during construction, which resulted from Carty being placed in service during 2016. In addition, there is a $3 million difference in the non-service cost component of net periodic pension expense reclassified to Miscellaneous income, net as a result of the adoption of ASU 2017-07, see Note 2, Summary of Significant Accounting Policies in Item 8. - "Financial Statements and Supplementary Data"

Income tax expense increased $36 million, or 72%, in 2017 compared with 2016. The change relates to a $13 million increase due to higher pre-tax income and $7 million due to lower production tax credits. Additionally, Income tax expense increased $17 million due to the remeasurement of deferred taxes pursuant to the change in corporate tax rates in the TCJA. For more information regarding the Company's approved OPUC order, see the "*Tax Reform*" Section of this Item 7.

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 2018 and projected capital expenditures and future debt maturities for 2019 through 2023 (in millions, excluding AFDC):

	Years Ending December 31,					
	2018	2019	2020	2021	2022	2023
Ongoing capital expenditures[1]	$ 580	$ 580	$ 500	$ 500	$ 500	$ 500
Customer information system[2]	26	—	—	—	—	—
Wheatridge Renewable Energy Facility	—	—	140	15	—	—
Total capital expenditures	$ 606 [3]	$ 580	$ 640	$ 515	$ 500	$ 500
Long-term debt maturities	$ —	$ 300	$ —	$ 160	$ —	$ —

(1) Consists primarily of upgrades to, and replacement of, generation, transmission, and distribution infrastructure, as well as new customer connects, and the non-utility purchase of PGE's corporate headquarters in 2018.
(2) Total capital expenditures for the customer information system through December 31, 2018 were $140 million, excluding AFDC.
(3) Includes preliminary engineering and removal costs, which are included in other net operating activities in the consolidated statements of cash flows.

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,		
	2018	2017	2016
Cash and cash equivalents, beginning of year	$ 39	$ 6	$ 4
Net cash provided by (used in):			
Operating activities	630	597	562
Investing activities	(471)	(514)	(585)
Financing activities	(79)	(50)	25
Net change in cash and cash equivalents	80	33	2
Cash and cash equivalents, end of year	$ 119	$ 39	$ 6

2018 Compared to 2017

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 $33 million increase in cash flows from operating activities in 2018 compared to 2017 is due to an overall increase in Net income of $25 million, an increase in Depreciation and amortization of $37 million due to higher average plant balances, an increase of $46 million in Accounts payable and accrued liabilities partially due to increased fuel costs from higher gas prices, and an increase of $45 million due to the net benefits received from tax reform. These costs were offset by a $87 million decrease in Deferred income taxes primarily due to the decrease in the corporate tax rate as a result of TCJA, and a $26 million increase in Accounts receivable and unbilled revenue.

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 2019 will range from $400 million to $420 million. Combined with all other sources, cash provided by operations in 2019 is estimated to range from $550 million to $600 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 $43 million decrease in net cash used in investing activities in 2018 compared with 2017 is primarily due to $120 million cash inflow as a result of the Carty litigation settlement, which was partially offset by higher capital expenditures largely due to a $45 million non-utility capital investment in the purchase of PGE's corporate headquarters.

The Company plans for approximately $580 million of capital expenditures in 2019 related to upgrades to and replacement of generation, transmission, and distribution infrastructure. PGE plans to fund the 2019 capital expenditures with cash from operations during 2019, 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 2018, cash used in financing activities consisted primarily of the issuance of $75 million of long-term debt, less the repayment $24 million of Pollution Control Bonds and payment of dividends in the amount of $125 million. During 2017, cash provided by financing activities consisted of the issuance of $225 million of long-term debt, less the repayment of $150 million of term loans and payment of dividends of $118 million.

2017 Compared to 2016

Cash Flows from Operating Activities—The $35 million increase in cash flows from operating activities in 2017 compared to 2016 reflects that while Net income was nearly comparable, adjustments to Net income to reconcile to net cash provided included increases of $33 million for Deferred income taxes ($17 million of which related to Tax reform), $19 million for Other non-cash income and expenses, and $24 million for Depreciation and amortization expense. PGE has reclassified $9 million from Other, net within the Cash flows from operating activities to Other, net within the Cash flows from financing activities on the consolidated statements of cash flows for the year ended December 31, 2016 as a result of the adoption of ASU 2016-15. For further information, see Note 2, Summary of Significant Accounting Policies in Item 8. Financial Statements and Supplementary Data.

Somewhat offsetting those increases were decreases of $28 million from Margin deposits outstanding due to changes in prices of power and fuel underlying contracts with counterparties and $16 million as a result of the decoupling mechanism, which reflects both the current year deferral and the refund to customers related to prior years.

Cash Flows from Investing Activities—The $71 million decrease in net cash used in investing activities in 2017 compared to 2016 was primarily due to a decrease in Capital expenditures as Carty was placed into service in July 2016.

Cash Flows from Financing Activities—During 2017, cash used in financing activities consisted primarily of the issuance of $225 million of long-term debt less the repayment of $150 million of term loans and payment of dividends of $118 million. During 2016, cash provided by financing activities consisted of issuance of $290 million of long-term debt less the repayment of $133 million of FMBs and the payment of dividends of $110 million.

Dividends on Common Stock

The following table presents common stock dividends declared in 2018:

Declaration Date	Record Date	Payment Date	Declared Per Common Share
February 14, 2018	March 26, 2018	April 16, 2018	$ 0.3400
April 25, 2018	June 25, 2018	July 16, 2018	0.3625
July 25, 2018	September 25, 2018	October 15, 2018	0.3625
October 24, 2018	December 26, 2018	January 15, 2019	0.3625

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. On February 13, 2019, a common stock dividend of $0.3625 per share was declared, payable April 15, 2019 to shareholders of record on March 25, 2019. 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.

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

Should 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, 2018, PGE had posted $64 million of collateral with these counterparties, consisting of $16 million in cash and $48 million in bank letters of credit, $11 million of which is related to master netting agreements. Based on the Company's energy portfolio, estimates of energy market prices, and the level of collateral outstanding as of December 31, 2018, the amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is $65 million and decreases to $20 million by December 31, 2019 and $7 million by December 31, 2020. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade is $162 million and decreases to $95 million by December 31, 2019 and $73 million by December 31, 2020.

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, 2018, under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust, the Company could have issued up to $1 billion 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, 2018, the Company's debt to total capital ratio, as calculated under the credit agreements, was 51.5%.

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.

For 2019, PGE expects to fund estimated capital requirements with cash from operations, the issuance of debt securities of up to $375 million, and the issuance of commercial paper, as needed. The actual timing and amount of any such issuances of debt or commercial paper will be dependent upon the timing and amount of capital expenditures.

Short-term Debt—Pursuant to an order issued by the FERC on January 3, 2018, PGE has authorization to issue short-term debt up to a total of $900 million through February 6, 2020.

As of December 31, 2018, PGE had a $500 million revolving credit facility scheduled to expire in November 2021. On January 15, 2019 PGE executed an amendment to the credit facility extending the termination date to November 14, 2022 and allowing for unlimited extension requests, provided that Lenders with a pro-rata share of more than 50%, approve the extension request. The revolving credit facility supplements operating cash flows and provides a primary source of liquidity. Pursuant to the terms of the agreement, the revolving credit facility may be used as backup for commercial paper borrowings, to permit the issuance of standby letters of credit, and 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, 2018, PGE had no borrowings outstanding, and no commercial paper or letters of credit issued. As a result, as of December 31, 2018, the aggregate unused available credit capacity under the revolving credit facility was $500 million.

In addition, PGE has four letter of credit facilities 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 $84 million were outstanding as of December 31, 2018.

Long-term Debt—During 2018, PGE issued a total of $75 million of FMBs at an interest rate of 4.47% with a maturity date of 2048. In addition, the Company repaid $24 million of Pollution Control Revenue Bonds that were early redeemed in October 2018.

As of December 31, 2018, total long-term debt outstanding, net of $10 million of unamortized debt expense, was $2,478 million, of which $300 million is scheduled to mature in 2019.

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 49.8% and 49.4% as of December 31, 2018 and 2017, respectively.

Contractual Obligations and Commercial Commitments

The following table presents PGE's contractual obligations as of December 31, 2018 (in millions):

	2019	2020	2021	2022	2023	There-after	Total
Long-term debt	$ 300	$ —	$ 160	$ —	$ —	$2,028	$2,488
Interest on long-term debt (1)	112	106	102	101	100	1,549	2,070
Capital and other purchase commitments	143	9	1	1	1	58	213
Purchased power and fuel:							
Electricity purchases	167	190	186	194	193	1,853	2,783
Capacity contracts	1	—	9	9	9	18	46
Public Utility Districts	12	11	9	8	8	35	83
Natural gas	54	42	31	31	30	208	396
Coal and transportation	6	—	—	—	—	—	6
Pension Plan Contributions (2)	—	41	26	30	31	—	128
Capital leases	6	6	6	6	5	67	96
Build-to-suit lease	11	14	13	13	13	225	289
Operating leases	4	5	5	6	7	97	124
Total	$ 816	$ 424	$ 548	$ 399	$ 397	$6,138	$8,722

(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, 2018.

(2) Contributions beyond 2023 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, $84 million has been issued as of December 31, 2018; and
- As a co-owner of Colstrip, PGE has provided surety bonds of $8 million in December 2018 and $10 million in January 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 Stations, 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 a third tranche of financial assurance to support additional 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 an operating 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.

Pension Plan

Primary assumptions used in the actuarial valuation of PGE’s pension plan include the discount rate, the expected return on plan assets, mortality rates, and wage escalation. These assumptions are evaluated by the Company, reviewed annually with the plan actuaries and trust investment consultants, and updated in light of market changes, trends, and future expectations. Significant differences between assumptions and actual experience can have a material impact on the valuation of the pension benefit plan obligation and net periodic pension cost.

PGE’s pension discount rate is determined based on a portfolio of high-quality bonds that match the duration of the plan cash flows. The expected rate of return on plan assets is based on the projected long-term return on assets in the plan investment portfolio. PGE capitalizes a portion of pension expense based on the proportion of labor costs capitalized.

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 2018 net periodic pension expense by approximately $2 million.

Fair Value Measurements

PGE applies fair value measurements to its financial assets and liabilities, with fair value defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The Company’s financial assets and liabilities consist of: i) derivative instruments entered into in connection with its price risk management activities; ii) the majority of assets held by the Nuclear decommissioning trust, the Pension plan, and the Non-qualified benefit plan trust; iii) long-term debt; and iv) interest rate swaps. In valuing these items, the Company uses inputs and assumptions that market participants would use to determine their fair value, utilizing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The determination of fair value can require subjective and complex judgment and PGE’s assessment of the inputs and the significance of a particular input to fair value measurement may affect the valuation of the instruments and their placement within the fair value hierarchy reported in its financial statements.

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, legal, rates and regulatory affairs, power operations, and generation operations. 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, 2018 that are expected to settle in each respective year (in millions):

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

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 in its energy portfolio. 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 monitors its exposure to fluctuations in the Canadian exchange rate with an appropriate hedging strategy.

As of December 31, 2018, 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, 2018, PGE had no borrowings outstanding under its revolving credit facility and no commercial paper or other short-term debt outstanding.

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

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

Until settlement, the interest rate swaps are carried at fair value as a derivative asset or liability with the corresponding offset recorded as either a regulatory liability or regulatory asset, respectively. The fair value of outstanding interest rate swap derivatives can vary significantly from period to period depending on the total notional amount of swap derivatives outstanding and fluctuations in market interest rates compared to the interest rates fixed by the swaps. As of December 31, 2018, the fair value of the interest rate swaps was a $4 million loss, which is recorded in Liabilities from price risk management activities—current on the Company's consolidated balance sheets.

As of December 31, 2018, 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	2019	2020	2021	2022	There-after
First Mortgage Bonds	$ 2,662	$ 2,390	$ 300	$ —	$ 160	$ —	$ 1,930
Pollution Control Revenue Bonds	98	98	—	—	—	—	98
Total	$ 2,760	$ 2,488	$ 300	$ —	$ 160	$ —	$ 2,028

As of December 31, 2018, 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. PGE 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. The Company 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, 2018, PGE's credit risk exposure is $20 million for commodity activities, of which $17 million is with externally-rated investment grade counterparties. The underlying transactions that make up the exposure will mature during 2019. 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, 2018 and 2017, 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, 2018, 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, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, 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, 2018, 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.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 14, 2019

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,		
	2018	**2017**	**2016**
Revenues:			
Revenues, net	$ 1,988	$ 2,009	$ 1,923
Alternative revenue programs, net of amortization	3	—	—
Total Revenues	1,991	2,009	1,923
Operating expenses:			
Purchased power and fuel	571	592	617
Generation, transmission and distribution	292	309	286
Administrative and other	271	260	240
Depreciation and amortization	382	345	321
Taxes other than income taxes	129	123	119
Total operating expenses	1,645	1,629	1,583
Income from operations	346	380	340
Interest expense, net	124	120	112
Other income:			
Allowance for equity funds used during construction	11	12	21
Miscellaneous income (expense), net	(4)	1	(6)
Other income, net	7	13	15
Income before income taxes	229	273	243
Income tax expense	17	86	50
Net income	$ 212	$ 187	$ 193
Weighted-average shares outstanding (in thousands):			
Basic	89,215	89,056	88,896
Diluted	89,347	89,176	89,054
Earnings per share:			
Basic	$ 2.38	$ 2.10	$ 2.17
Diluted	$ 2.37	$ 2.10	$ 2.16

See accompanying notes to consolidated financial statements.

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

	Years Ended December 31,		
	2018	**2017**	**2016**
Net income	$ 212	$ 187	$ 193
Other comprehensive income (loss)—Change in compensation retirement benefits liability and amortization, net of taxes of an immaterial amount in 2018, 2017, and 2016	1	(1)	1
Comprehensive income	$ 213	$ 186	$ 194

See accompanying notes to consolidated financial statements.

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

	As of December 31,	
	2018	**2017**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 119	$ 39
Accounts receivable, net	193	168
Unbilled revenues	96	106
Inventories, at average cost:		
Materials and supplies	53	52
Fuel	31	26
Regulatory assets—current	61	62
Other current assets	90	73
Total current assets	643	526
Electric utility plant:		
Generation	4,600	4,667
Transmission	580	547
Distribution	3,838	3,543
General	611	550
Intangible	715	607
Construction work-in-progress	346	391
Total electric utility plant	10,690	10,305
Accumulated depreciation and amortization	(3,803)	(3,564)
Electric utility plant, net	6,887	6,741
Regulatory assets—noncurrent	401	438
Nuclear decommissioning trust	42	42
Non-qualified benefit plan trust	36	37
Other noncurrent assets	101	54
Total assets	$ 8,110	$ 7,838

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,	
	2018	**2017**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 168	$ 132
Liabilities from price risk management activities—current	55	59
Current portion of long-term debt	300	—
Accrued expenses and other current liabilities	268	241
Total current liabilities	791	432
Long-term debt, net of current portion	2,178	2,426
Regulatory liabilities—noncurrent	1,355	1,288
Deferred income taxes	369	376
Unfunded status of pension and postretirement plans	307	284
Liabilities from price risk management activities—noncurrent	101	151
Asset retirement obligations	197	167
Non-qualified benefit plan liabilities	103	106
Other noncurrent liabilities	203	192
Total liabilities	5,604	5,422
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; 89,267,959 and 89,114,265 shares issued and outstanding as of December 31, 2018 and 2017, respectively	1,212	1,207
Accumulated other comprehensive loss	(7)	(8)
Retained earnings	1,301	1,217
Total shareholders' equity	2,506	2,416
Total liabilities and shareholders' equity	$ 8,110	$ 7,838

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, 2015	88,792,751	$ 1,196	$ (8)	$ 1,070	$ 2,258
Shares issued pursuant to equity-based plans	153,953	1	—	—	1
Stock-based compensation	—	4	—	—	4
Dividends declared ($1.26 per share)	—	—	—	(113)	(113)
Net income	—	—	—	193	193
Other comprehensive income	—	—	1	—	1
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

See accompanying notes to consolidated financial statements.

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

	Years Ended December 31,		
	2018	**2017**	**2016**
Cash flows from operating activities:			
Net income	$ 212	$ 187	$ 193
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	382	345	321
Deferred income taxes	(17)	70	37
Allowance for equity funds used during construction	(11)	(12)	(21)
Pension and other postretirement benefits	30	24	28
Decoupling mechanism deferrals, net of amortization	(2)	(22)	(6)
Deferral of net benefits due to Tax Reform	45	—	—
Other non-cash income and expenses, net	21	31	12
Changes in working capital:			
(Increase) in receivables and unbilled revenues	(29)	(3)	(9)
(Increase) decrease in margin deposits	(5)	(3)	25
Increase in payables and accrued liabilities	51	5	15
Other working capital items, net	(11)	1	(4)
Contribution to non-qualified employee benefit trust	(11)	(8)	(10)
Contribution to pension and other postretirement plans	(12)	(5)	(2)
Other, net	(13)	(13)	(17)
Net cash provided by operating activities	630	597	562
Cash flows from investing activities:			
Capital expenditures	(595)	(514)	(584)
Purchases of nuclear decommissioning trust securities	(12)	(18)	(25)
Sales of nuclear decommissioning trust securities	15	21	27
Proceeds from Carty Settlement	120	—	—
Other, net	1	(3)	(3)
Net cash used in investing activities	(471)	(514)	(585)

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,		
	2018	**2017**	**2016**
Cash flows from financing activities:			
Proceeds from issuance of long-term debt	$ 75	$ 225	$ 290
Payments on long-term debt	(24)	(150)	(133)
(Maturities) issuances of commercial paper, net	—	—	(6)
Dividends paid	(125)	(118)	(110)
Other	(5)	(7)	(16)
Net cash (used in) provided by financing activities	(79)	(50)	25
Increase in cash and cash equivalents	80	33	2
Cash and cash equivalents, beginning of year	39	6	4
Cash and cash equivalents, end of year	$ 119	$ 39	$ 6
Supplemental disclosures of cash flow information:			
Cash paid for:			
Interest, net of amounts capitalized	$ 117	$ 110	$ 104
Income taxes	25	18	16
Non-cash investing and financing activities:			
Accrued capital additions	61	53	50
Accrued dividends payable	34	31	30
Assets obtained under leasing arrangements	24	87	78

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, of which Portland and Salem are the largest. As of December 31, 2018, PGE served approximately 885,000 retail customers with a service area population of approximately 1.9 million, comprising approximately 46% of the population of the state.

As of December 31, 2018, PGE had 2,967 employees, with 802 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 747 and 55 employees and expire March 2020 and August 2022, respectively.

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

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 17, 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 2018 presentation, PGE has reclassified Unrealized losses on non-qualified benefit plan trust assets of $2 million and $5 million in 2017 and 2016, respectively, to Other non-cash income and expenses, net within the operating section of the Consolidated Statements of Cash Flows. PGE has also reclassified Contribution to pension and other postretirement plans of $5 million and $2 million in 2017 and 2016, respectively, from Other, net to its own line item within the operating 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 $112 million as of December 31, 2018 and $30 million as of December 31, 2017 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 2018, 2017, or 2016.

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 power costs for the Company's retail customers.

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

Physically settled electricity and natural gas sale and purchase transactions are recorded in 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 with certain counterparties. The collateral requirements are based on the contract terms and commodity prices and can vary period to period. Cash deposits provided as collateral are included within Other current assets in the consolidated balance sheets and were $16 million and $11 million as of December 31, 2018 and 2017, respectively. Letters of credit provided as collateral are not recorded on the Company's consolidated balance sheets and were $48 million and $31 million as of December 31, 2018 and 2017, respectively.

Inventories

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

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 7.3% in 2018, 2017, and 2016. AFDC from borrowed funds was $6 million in 2018 and 2017, and $11 million in 2016 and is reflected as a reduction to Interest expense, net. AFDC from equity funds, included in Other income, net, was $11 million in 2018, $12 million in 2017, and $21 million in 2016.

Depreciation and Amortization

Depreciation is computed using the straight-line method, based upon original cost, and includes an estimate for cost of removal and expected salvage. Depreciation expense as a percent of the related average depreciable plant in service was 3.6% in 2018 and 2017, and 3.5% in 2016. A component of depreciation expense includes estimated asset retirement removal costs allowed in customer prices.

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

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

Generation, excluding thermal:	
Hydro	99
Wind	30
Transmission	59
Distribution	46
General	12

When property is retired and removed from service, the original cost of the depreciable property units, net of any related salvage value, is charged to accumulated depreciation. Cost of removal expenditures are recorded against AROs or to accumulated 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 $302 million and $296 million as of December 31, 2018 and 2017, respectively, with amortization expense of $59 million in 2018, and $46 million in 2017 and $44 million in 2016. Future estimated amortization expense as of December 31, 2018 is as follows: $60 million in 2019; $52 million in 2020; $44 million in 2021; $38 million in 2022; and $29 million in 2023.

Marketable Securities

All of PGE's investments in marketable securities, included in the Non-qualified benefit plan trust and Nuclear decommissioning trust on the 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 Non-qualified benefit plan trust assets are included in Other income, net. Realized and unrealized gains and losses on the Nuclear decommissioning trust 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, the Company can adjust future customer prices to reflect a portion of the difference between: i) net variable power costs (NVPC) forecast each year and included in customer prices (baseline NVPC); and ii) actual NVPC. NVPC consists of the cost of power purchased and fuel used to generate electricity to meet PGE's retail load requirements, as well as the cost of settled electric and natural gas financial contracts, all of which is classified as Purchased power 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 2018, and 9.6% for 2017 and 2016.

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. Such estimates are revised periodically, with actual expenditures charged to the ARO as incurred.

The estimated capitalized costs of AROs are depreciated over the estimated life of the related asset, which is included in Depreciation 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, 2018, PGE had a net regulatory liability related to Utility plant AROs in the amount of $53 million and a net regulatory asset related to Trojan decommissioning ARO activities of $25 million. As of December 31, 2017, PGE had a net regulatory liability related to Utility plant AROs in the amount of $52 million and a net regulatory liability related to Trojan decommissioning ARO activities of $3 million. For additional information concerning the Company's regulatory liability related to AROs, see Note 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.

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

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

For additional information concerning the Company's contingencies, see Note 18, 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 goods and services provided, are regulated by the Public Utility Commission of Oregon (OPUC) or the Federal Energy Regulatory Commission (FERC). PGE recognizes revenue through the following steps: i) identifying the contract with the customer; ii) identifying the performance obligations in the contract; iii) determining the transaction price; iv) allocating the transaction price to the performance obligations; and v) recognizing revenue when or as each performance obligation is satisfied.

Franchise taxes, which are collected from customers and remitted to taxing authorities, are recorded on a gross basis in PGE's 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 2018, and $43 million in 2017 and 2016.

Retail revenue is billed based on monthly meter readings taken at various cycle dates throughout the month. At the end of each month, PGE estimates the revenue earned from energy deliveries that has not yet been billed to customers. This amount, which is classified as Unbilled revenues in the Company's 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 and renewable adjustment clause (RAC) mechanisms are considered earned under alternative revenue programs, in accordance with the new revenue standard. 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, as these amounts represent a contract with the regulator and not with customers. 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 $267 million and $277 million as of December 31, 2018, and 2017, respectively, and will 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 February 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2016-02, *Leases (Topic 842)*, which supersedes the current lease accounting requirements for lessees and lessors within Topic 840, Leases. Pursuant to the new standard, lessees will be required to recognize all leases, including operating leases, on the balance sheet and record corresponding right-of-use (ROU) assets and lease liabilities. Accounting for lessors is substantially unchanged from current accounting principles. Lessees will be required to classify leases as either finance leases or operating leases. Initial balance sheet measurement is similar for both types of leases; however, expense recognition and amortization of right-of-use assets will differ.

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

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

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

In February 2018, the FASB issued ASU 2018-02 *Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income* (ASU 2018-02). ASU

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

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

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

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

Recently Adopted Accounting Pronouncements

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

PGE's transition to the new revenue standard did not result in a material adjustment to opening retained earnings and the Company expects the adoption of the new standard to have an immaterial impact to its results of operations on an ongoing basis. In accordance with the new provisions of Topic 606, PGE has included enhanced quantitative and qualitative disclosures, such as disaggregated revenues by customer class. Adoption of the new standard also resulted in a change to PGE's presentation and classification of its alternative revenue programs, which are predominately comprised of the decoupling and RAC mechanisms. Pursuant to the new standard, such revenues should be presented separately from revenues from contracts with customers as these amounts represent a contract with the regulator and not with customers. As a result, $3 million, net of amortization, primarily related to PGE's decoupling mechanism, has been classified as Alternative revenue programs, net of amortization in the consolidated statements of income as of December 31, 2018. If PGE had not applied the new provisions of Topic 606, then PGE would have reported Revenues, net of $1,991 million under Topic 605 for the year ended December 31, 2018, with the difference attributable to the presentation and classification of alternative revenue programs. For further information regarding changes to the Company's revenue recognition accounting policies, see Note 3, Revenue Recognition.

On January 1, 2018, PGE adopted ASU 2017-07, *Compensation-Retirement Benefits (Topic 715), Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. On a prospective basis, only the service cost component of net periodic pension and postretirement benefit costs is eligible for capitalization to Electric utility plant, net. However, for ratemaking purposes the Company will continue to be allowed to recover its non-service costs related to capital projects as a component of rate base. Instead of recording such amounts to Electric utility plant, net, the Company will record a Regulatory asset on the consolidated balance sheet that will be amortized in a systematic and rational manner. As of December 31, 2018, the Company has recorded $3 million of the non-service costs component of net periodic pension and postretirement benefit costs as a Regulatory asset. The new pronouncement also requires, on a retrospective basis, that the non-service cost component of net periodic pension and postretirement benefit costs attributable to expense be presented separately from the service cost component and outside the subtotal of income from operations on the consolidated statements of income. As of December 31, 2018, the portion of non-service costs attributable to expense is $5 million, classified as Miscellaneous income (expense), net within Other income on the Company's consolidated statements of income. To conform to the 2018 presentation, PGE has retrospectively reclassified $4 million and $7 million, respectively, of the non-service costs component for the years ended December 31, 2017 and December 31, 2016 from Administrative and other within Operating expenses to Miscellaneous income (expense), net within Other income. The implementation of ASU 2017-07 has had an immaterial impact on PGE's consolidated financial position and consolidated results of operations.

On January 1, 2018, PGE adopted ASU 2016-15, *Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments*, which provided guidance for eight specific cash flow issues where there had historically been diversity in practice. The eight areas of the cash flow impacted were debt prepayment or debt extinguishment costs, settlement of zero-coupon debt instruments, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance (COLI) policies, distributions received from equity method investments, beneficial interest in securitization transactions, and separately identifiable cash flows and application of the predominance principal. The standard required a retrospective transition approach, and as such, PGE has reclassified $9 million from Other, net within the Cash flows from operating activities to Other, net within the Cash flows from financing activities on the consolidated statements of cash flows for the year ended December 31, 2016. The standard did not have a material impact to PGE for any other area for which guidance was provided on the statement of cash flows. The implementation of ASU 2016-15 has had an immaterial impact on PGE's consolidated financial position and consolidated results of operations.

In August 2017, the FASB issued ASU 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities*. The ASU is intended to simplify the application of hedge accounting and provide increased transparency as to the scope and results of hedging programs. For calendar year-end entities, the update will be effective for annual periods beginning January 1, 2019, and interim periods within those fiscal years. PGE early adopted the standard in April 2018 and applied its provisions to the Company's interest rate swaps that were entered into in 2018 and are designated as cash flow hedges to hedge portions of consolidated interest rate risk associated with anticipated issues of fixed-rate, long-term debt securities. The current impact of this adoption is immaterial to PGE's consolidated financial statements as the majority of PGE's price risk management derivatives are related to electric and natural gas commodity price economic hedges that are deferred for ratemaking purposes.

NOTE 3: REVENUE RECOGNITION

Disaggregated Revenue

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

	Year Ended December 31, 2018
Retail:	
Residential	$ 948
Commercial	647
Industrial	185
Direct access customers	43
Subtotal	1,823
Alternative revenue programs, net of amortization	3
Other accrued (deferred) revenues, net(1)	(45)
Total retail revenues	1,781
Wholesale revenues(2)	159
Other operating revenues	51
Total revenues	$ 1,991

(1) Amount primarily related to the regulatory liability deferral of 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 $42 million related to electricity commodity contract derivative settlements for the year ended December 31, 2018. Price risk management derivative activities are included within Total revenues but do not represent revenues from contracts with customers pursuant to Topic 606. For further information, see Note 6, Risk Management.

Retail Revenues

The Company's primary revenue source is generated through the sale of electricity to customers based on 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 season and summer cooling season. 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 for residential and small commercial customers.

PGE's obligation to sell electricity to retail customers generally represents a single performance obligation representing a series of distinct goods 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 to transfer each distinct delivery of electricity in the series to the customer.

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 are not reflected 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 and wind conditions, and daily and seasonal retail demand.

The majority of PGE's wholesale electricity sales is to utilities and power marketers, is predominantly short-term, and consists of a single performance obligation 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 resales, 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 $15 million as of December 31, 2018 and $6 million as of December 31, 2017. The following is the activity in the allowance for uncollectible accounts (in millions):

	Years Ended December 31,		
	2018	**2017**	**2016**
Balance as of beginning of year	$ 6	$ 6	$ 6
Increase in provision	14	6	5
Amounts written off, less recoveries	(5)	(6)	(5)
Balance as of end of year	$ 15	$ 6	$ 6

Trust Accounts

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

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

The trusts are comprised of the following investments as of December 31 (in millions):

	Nuclear Decommissioning Trust		Non-Qualified Benefit Plan Trust	
	2018	2017	2018	2017
Cash equivalents	$ 7	$ 25	$ 2	$ 1
Marketable securities, at fair value:				
Equity securities	—	—	6	7
Debt securities	35	17	1	1
Insurance contracts, at cash surrender value	—	—	27	28
	$ 42	$ 42	$ 36	$ 37

For information concerning the fair value measurement of those assets recorded at fair value held in the trusts, see Note 5, Fair Value of Financial Instruments.

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,	
	2018	2017
Other current assets:		
Prepaid expenses	$ 54	$ 50
Margin deposits	16	11
Assets from price risk management activities	20	6
Other	—	6
	$ 90	$ 73
Accrued expenses and other current liabilities:		
Regulatory liabilities—current	$ 36	$ 31
Accrued employee compensation and benefits	66	60
Accrued dividends payable	34	31
Accrued interest payable	27	27
Accrued taxes payable	34	31
Other	71	61
	$ 268	$ 241

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

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

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

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

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

PGE recognizes transfers between levels in the fair value hierarchy as of the end of the reporting period for all of its financial instruments. Changes to market liquidity conditions, the availability of observable inputs, or changes in the economic structure of a security marketplace may require transfer of the securities between levels. There were no significant transfers between levels during the years ended December 31, 2018 and 2017, except those presented in this note.

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

	As of December 31, 2018				
	Level 1	**Level 2**	**Level 3**	**Other[2]**	**Total**
Assets:					
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.

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

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in 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 $28 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 the fund's securities holdings do not exceed 90 days and investors have the ability to redeem the fund's shares daily at its respective net asset value. These 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 NASDAQ and the New York Stock Exchange.

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 New York Stock Exchange (NYSE).

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

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

Liabilities from interest rate swap derivatives are recorded at fair value in PGE's 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 the Company's retail customers. 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, 2018:							
Electricity physical forward	$ 3	$ 84	Discounted cash flow	Electricity forward price (per MWh)	$ 14.60	$ 69.00	$ 45.00
Natural gas financial swaps	—	7	Discounted cash flow	Natural gas forward price (per Dth)	0.95	4.64	1.82
Electricity financial futures	—	—	Discounted cash flow	Electricity forward price (per MWh)	20.75	35.46	28.63
	$ 3	$ 91					
As of December 31, 2017:							
Electricity physical forward	$ —	$ 130	Discounted cash flow	Electricity forward price (per MWh)	$ 7.79	$ 41.23	$ 30.95
Natural gas financial swaps	—	9	Discounted cash flow	Natural gas forward price (per Dth)	1.26	2.92	1.90
Electricity financial futures	—	—	Discounted cash flow	Electricity forward price (per MWh)	7.79	29.74	21.74
	$ —	$ 139					

The significant unobservable inputs used in the Company's fair value measurement of price risk management assets and liabilities are long-term forward prices for commodity derivatives. For shorter term contracts, PGE employs the mid-point of the bid-ask spread of the market and these inputs are derived using observed transactions in active markets, as well as historical experience as a participant in those markets. These price inputs are validated against independent market data from multiple sources. For certain long-term contracts, observable, liquid market transactions are not available for the duration of the delivery period. In such instances, the Company uses internally-developed price curves, which derive longer term prices and utilize observable data when available. When not available, regression techniques are used to estimate unobservable future prices. In addition, changes in the fair value measurement of price risk management assets and liabilities are analyzed and reviewed on a quarterly basis by the Company.

The Company's Level 3 assets and liabilities from price risk management activities are sensitive to market price changes in the respective underlying commodities. The significance of the impact is dependent upon the magnitude of the price change and the Company's position as either the buyer or seller of the contract. Sensitivity of the fair value measurements to changes in the significant unobservable inputs is as follows:

Significant Unobservable Input	Position	Change to Input	Impact on Fair Value Measurement
Market price	Buy	Increase (decrease)	Gain (loss)
Market price	Sell	Increase (decrease)	Loss (gain)

Changes in the fair value of net liabilities from price risk management activities (net of assets from price risk management activities) classified as Level 3 in the fair value hierarchy were as follows (in millions):

	Years Ended December 31, 2018	Years Ended December 31, 2017
Net liabilities from price risk management activities as of beginning of year	$ 139	$ 119
Net realized and unrealized losses *	(40)	35
Net transfers out of Level 3 to Level 2	(11)	(15)
Net liabilities from price risk management activities as of end of year	$ 88	$ 139
Level 3 net unrealized losses that have been fully offset by the effect of regulatory accounting	$ 32	$ 41

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

Transfers into Level 3 occur when significant inputs used to value the Company's derivative instruments become less observable, such as a delivery location becoming significantly less liquid. During the years ended December 31, 2018 and 2017, there were no transfers into Level 3 from Level 2. Transfers out of Level 3 occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery term of a transaction becomes shorter. PGE records transfers in and transfers out of Level 3 at the end of the reporting period for all of its derivative instruments.

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

Long-term debt is recorded at amortized cost in PGE's consolidated balance sheets. The fair value of the Company's First Mortgage Bonds (FMBs) and Pollution Control Revenue Bonds (PCBs) is classified as a Level 2 fair value measurement.

As of December 31, 2018, the carrying amount of PGE's long-term debt was $2,478 million, net of $10 million of unamortized debt expense, and its estimated aggregate fair value was $2,760 million, all of which is classified as Level 2 in the fair value hierarchy. As of December 31, 2017, the carrying amount of PGE's long-term debt was $2,426 million, net of $10 million of unamortized debt expense, with an estimated aggregate fair value of $2,829 million, all of which was classified as Level 2 in the fair value hierarchy.

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

NOTE 6: RISK MANAGEMENT

Price Risk Management

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

PGE utilizes derivative instruments to manage its exposure to commodity price risk and foreign exchange rate risk in order to manage volatility in NVPC for its retail customers. Such derivative instruments, recorded at fair value on the 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,	
	2018	2017
Current assets:		
Commodity contracts:		
Electricity	$ 11	$ 3
Natural gas	7	3
Total current derivative assets	18 (1)	6 (1)
Noncurrent assets:		
Commodity contracts:		
Electricity	1	—
Natural gas	1	—
Total noncurrent derivative assets	2 (2)	— (2)
Total derivative assets not designated as hedging instruments	$ 20	$ 6
Total derivative assets	$ 20	$ 6
Current liabilities:		
Commodity contracts:		
Electricity	$ 16	$ 13
Natural gas	35	46
Total current derivative liabilities	51	59
Noncurrent liabilities:		
Commodity contracts:		
Electricity	78	122
Natural gas	23	29
Total noncurrent derivative liabilities	101	151
Total derivative liabilities not designated as hedging instruments	$ 152	$ 210
Total derivative liabilities	$ 152	$ 210

(1) Included in Other current assets on the consolidated balance sheets.
(2) Included in Other noncurrent assets on the consolidated balance sheets.

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

	As of December 31,					
	2018			2017		
Commodity contracts:						
Electricity		5	MWh		7	MWh
Natural gas		123	Dth		114	Dth
Foreign currency exchange	$	18	Canadian	$	21	Canadian

PGE has elected to report gross on the consolidated balance sheets the positive and negative exposures resulting from derivative instruments pursuant to agreements that meet the definition of a master netting arrangement. In the case of default on, or termination of, any contract under the master netting arrangements, such agreements provide for the net settlement of all related contractual obligations with a given counterparty through a single payment. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, receivables and payables arising from settled positions, and other forms of non-cash collateral, such as letters of credit. As of December 31, 2018, and 2017, gross amounts included as Price risk management liabilities subject to master netting agreements were $88 million and $136 million, respectively, for which PGE posted collateral of $11 million for 2018 and 2017, which consisted entirely of letters of credit. As of December 31, 2018, of the gross amounts included, $84 million was for electricity and $4 million was for natural gas compared to $130 million for electricity and $6 million for natural gas recognized as of December 31, 2017.

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

	Years Ended December 31,					
	2018		2017		2016	
Commodity contracts:						
Electricity	$	(34)	$	41	$	34
Natural Gas		21		85		(56)
Foreign currency exchange		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 $18 million, net losses of $82 million, and net gains of $13 million for the years ended December 31, 2018, 2017, and 2016, respectively, have been offset.

Assuming no changes in market prices and interest rates, the following table presents the year in which the net unrealized loss recorded as of December 31, 2018 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

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

PGE's secured and unsecured debt is currently rated at investment grade by Moody's Investors Service (Moody's) and S&P Global Ratings (S&P). Should Moody's and/or S&P reduce their rating on the Company's unsecured debt to below investment grade, PGE could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, in the form of cash or letters of credit, based on total portfolio positions with each of those counterparties. Certain other counterparties would have the right to terminate their agreements with the Company.

The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position as of December 31, 2018 was $144 million, for which the Company had posted $48 million in collateral, consisting entirely of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at December 31, 2018, the cash requirement to either post as collateral or settle the instruments immediately would have been $136 million. As of December 31, 2018, PGE had no posted cash collateral for derivative instruments with no credit-risk-related contingent features. Cash collateral for derivative instruments is classified as 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,	
	2018	2017
Assets from price risk management activities:		
Counterparty A	42%	39%
Counterparty B	15	—
Counterparty C	5	12
	62%	51%
Liabilities from price risk management activities:		
Counterparty D	56%	62%
	56%	62%

For additional information concerning the determination of fair value for the Company's Assets and Liabilities from price risk management activities, see Note 5, Fair Value of Financial Instruments.

Interest Rate Risk

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

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

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

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,			
		2018			2017
	Remaining Amortization Period	Earning a Return (1)	Not Earning a Return	Total	Total
Regulatory assets:					
Price risk management	2035	$ —	$ 131	$ 131	$ 204
Pension and other postretirement plans	(2)	—	222	222	218
Debt issuance costs	2036	—	16	16	19
Trojan decommissioning activities	2039	26	—	26	—
Other	Various	53	14	67	59
Total regulatory assets		$ 79	$ 383	$ 462	$ 500
Regulatory liabilities:					
Asset retirement removal costs	(3)	$ 979	$ —	$ 979	$ 933
Deferred income taxes	(4)	267	—	267	277
Trojan decommissioning activities	2019	1	—	1	3
Asset retirement obligations	(3)	53	—	53	52
Tax Reform Deferral (5)	2020	45	—	45	—
Other	Various	39	7	46	54
Total regulatory liabilities		$ 1,384	$ 7	$ 1,391	$ 1,319

(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 net balance and treated as a reduction to rate base.
(4) Will be returned to customers using the average rate assumption method over the average life of the underlying assets and treated as a reduction to rate base.
(5) Related to the deferral of the 2018 net tax benefits due to the change in corporate tax rate under TCJA, including interest.

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.

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

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

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.

Trojan decommissioning activities represents proceeds received for the settlement of a legal matter concerning the reimbursement from the United States Department of Energy (USDOE) of certain monitoring costs incurred related to spent nuclear fuel at Trojan, as well as ongoing costs and collections associated with decommissioning activities.

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

NOTE 8: ASSET RETIREMENT OBLIGATIONS

AROs consist of the following (in millions):

	As of December 31,	
	2018	**2017**
Trojan decommissioning activities	$ 68	$ 45
Utility plant	112	109
Non-utility property	17	13
Asset retirement obligations	$ 197	$ 167

Trojan decommissioning activities represents the present value of future decommissioning costs for the plant, which ceased operation in 1993. The remaining decommissioning activities primarily consist of the long-term operation and decommissioning of the ISFSI, an interim dry storage facility that is licensed by the Nuclear Regulatory Commission. The ISFSI is to house the spent nuclear fuel at the former plant site until an off-site storage facility is available. Decommissioning of the ISFSI and final site restoration activities will begin once shipment of all the spent fuel to a USDOE facility is complete, which is not expected prior to 2034. The NRC has mandated an increase in staffing for the next 16 years that has led to an increase in the Trojan ARO by $23 million in the first quarter of 2018. The Company also recorded accretion of $4 million and a reduction of $4 million due to settled liabilities.

In 2004, the co-owners of Trojan (PGE, Eugene Water & Electric Board, and PacifiCorp, collectively referred to as Plaintiffs) filed a complaint against the USDOE for failure to accept spent nuclear fuel by January 31, 1998. PGE, which holds a 67.5% ownership interest in Trojan, had contracted with the USDOE for the permanent disposal of spent nuclear fuel in order to allow the final decommissioning of Trojan. The Plaintiffs paid for permanent disposal services during the period of plant operation and have met all other conditions precedent. The Plaintiffs sought reimbursement for damages incurred through 2009.

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

The ARO related to Trojan decommissioning activities was not impacted by the outcome of this legal matter because the proceeds received in connection with the settlement of this legal matter were for past Trojan decommissioning costs and this ARO reflects future Trojan decommissioning costs.

Utility plant represents AROs that have been recognized for the Company's thermal and wind generation sites, distribution and transmission assets, the disposal of which is governed by environmental regulation. During 2018, the Company recorded an overall increase in utility AROs of $3 million, with the change comprised of accretion of $4 million, and a reduction of $1 million due to settled liabilities.

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

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

	Years Ended December 31,		
	2018	2017	2016
Balance as of beginning of year	$ 167	$ 161	$ 151
Liabilities incurred	—	2	1
Liabilities settled	(5)	(3)	(3)
Accretion expense	8	7	7
Revisions in estimated cash flows	27	—	5
Balance as of end of year	$ 197	$ 167	$ 161

Pursuant to regulation, the amortization of utility plant AROs is included in depreciation expense and in customer prices. Any differences in the timing of recognition of costs for financial reporting and ratemaking purposes are deferred as a regulatory asset or regulatory liability. Recovery of Trojan decommissioning costs is included in PGE's retail prices, approximately $4 million annually, with an equal amount recorded in 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. See "*Trust Accounts*" in Note 4, Balance Sheet Components, for additional information on the NDT.

The Oak Grove hydro facility and transmission and distribution plant located on public right-of-ways and on certain easements meet the requirements of a legal obligation and will require removal when the plant is no longer in service. An ARO liability is not currently measurable as management believes that these assets will be used in utility operations for the foreseeable future. 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, 2018, PGE had a $500 million revolving credit facility scheduled to expire in November 2021. On January 16, 2019 PGE executed an amendment to the credit facility extending the termination date to November 14, 2022 and allowing for unlimited extension requests, provided that lenders with a pro-rata share of more than 50%, approve the extension request. Pursuant to the terms of the agreement, the revolving credit facility may be used for general corporate purposes, as backup for commercial paper borrowings, and to permit the issuance of standby letters of credit. PGE may borrow for one, two, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the applicable credit facility. The revolving credit facility contains a provision that requires annual fees based on PGE's unsecured credit ratings, and contains customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the agreement, to 65.0% of total capitalization. As of December 31, 2018, PGE was in compliance with this covenant with a 51.5% debt to total capital ratio.

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

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

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

In addition, PGE has four letter of credit facilities that provide capacity up to a total of $220 million under which the Company can request letters of credit for original terms not to exceed one year. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these facilities, $84 million were issued, as of December 31, 2018. Letters of credit issued are not reflected on the Company's 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 6, 2020.

Short-term borrowings under these credit facilities and related interest rates are reflected in the following table (dollars in millions). The Company had no short-term borrowings during 2018.

	Years Ended December 31,		
	2018	2017	2016
Average daily amount of short-term debt outstanding	$ —	$ —	$ 1
Weighted daily average interest rate *	—%	—%	0.7%
Maximum amount outstanding during the year	$ —	$ —	$ 23

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

NOTE 10: LONG-TERM DEBT

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

	As of December 31,	
	2018	2017
First Mortgage Bonds, rates range from 2.51% to 9.31%, with a weighted average rate of 5.01% in 2018 and 5.03% in 2017, due at various dates through 2048	$ 2,390	$ 2,315
Pollution Control Revenue Bonds, 5% rate, due 2033	119	142
Pollution Control Revenue Bonds owned by PGE	(21)	(21)
Total long-term debt	2,488	2,436
Less: Unamortized debt expense	(10)	(10)
Less: Current portion of long-term debt	(300)	—
Long-term debt, net of current portion	$ 2,178	$ 2,426

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

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

Pollution Control Revenue Bonds—The Company has the option to remarket through 2033 the $21 million of Pollution Control Revenue Bonds (PCBs) held by PGE as of December 31, 2018. At the time of any remarketing, the Company can choose a new interest rate period that could be daily, weekly, or a fixed term. The new interest rate would be based on market conditions at the time of remarketing. The PCBs could be backed by FMBs or a bank letter of credit depending on market conditions. Interest is payable semi-annually on PCBs. The Company repaid $24 million of Pollution Control Revenue Bonds that were early redeemed in October 2018.

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

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

NOTE 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 most new employees since January 31, 2009 and to all new employees since January 1, 2012. No changes were made to the benefits provided to existing participants when the plan was closed to new employees.

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

PGE contributed $9 million to the pension plan in 2018, $2 million in 2017, and nothing in 2016. PGE does not expect to contribute to the pension plan in 2019.

Other Postretirement Benefits—PGE has non-contributory postretirement health and life insurance plans, as well as health reimbursement arrangements (HRAs) for its employees (collectively, "Other Postretirement Benefits" in the following tables). Participants are covered under a Defined Dollar Medical Benefit Plan, which limits PGE's obligation pursuant to the postretirement health plan by establishing a maximum benefit per employee with employees responsible for the additional cost.

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

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

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

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

	2018			2017		
	NQBP	**Other NQBP**	**Total**	**NQBP**	**Other NQBP**	**Total**
Non-qualified benefit plan trust	$ 16	$ 20	$ 36	$ 17	$ 20	$ 37
Non-qualified benefit plan liabilities *	22	81	103	25	81	106

* For the NQBP, excludes the current portion of $2 million in 2018 and in 2017, which are classified in Other current liabilities in the consolidated balance sheets.

See "*Trust Accounts*" in Note 4, Balance Sheet Components, for information on the NQBP trust.

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

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

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

* The target for the Defined Benefit Pension Plan represents the mid-point of the investment target range. Due to the nature of the investment vehicles in both the Other Postretirement Benefit Plans and the NQBP, these targets are the weighted average of the mid-point of the respective investment target ranges approved by the Investment Committee. Due to the method used to calculate the weighted average targets for the Other Postretirement Benefit Plans and NQBP, reported percentages are affected by the fair market values of the investments within the pools.

The Company's overall investment strategy is to meet the goals and objectives of the individual plans through a wide diversification of asset types, fund strategies, and fund managers. Equity securities primarily include investments across the capitalization ranges and style biases, both domestically and internationally. Fixed income securities include, but are not limited to, corporate bonds of companies from diversified industries, mortgage-backed securities, and U.S. Treasuries. Other types of investments include investments in hedge funds and private equity funds that follow several different strategies.

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

The fair values of the Company's pension plan assets and other postretirement benefit plan assets by asset category are as follows (in millions):

	Level 1	Level 2	Level 3	Other *	Total
As of December 31, 2018:					
Defined Benefit Pension Plan assets:					
Equity securities—Domestic	$ 67	$ —	$ —	$ —	$ 67
Investments measured at NAV:					
Money market funds	—	—	—	5	5
Collective trust funds	—	—	—	463	463
Private equity funds	—	—	—	11	11
	$ 67	$ —	$ —	$ 479	$ 546
Other Postretirement Benefit Plans assets:					
Money market funds	$ 3	$ —	$ —	$ —	$ 3
Equity securities:					
Domestic	—	3	—	—	3
International	8	—	—	—	8
Debt securities—Domestic government	—	5	—	—	5
Investments measured at NAV:					
Money market funds	—	—	—	4	4
Collective trust funds	—	—	—	7	7
	$ 11	$ 8	$ —	$ 11	$ 30
As of December 31, 2017:					
Defined Benefit Pension Plan assets:					
Equity securities—Domestic	$ 83	$ —	$ —	$ —	$ 83
Investments measured at NAV:					
Money market funds	—	—	—	5	5
Collective trust funds	—	—	—	528	528
Private equity funds	—	—	—	13	13
	$ 83	$ —	$ —	$ 546	$ 629
Other Postretirement Benefit Plans assets:					
Money market funds	$ 3	$ —	$ —	$ —	$ 3
Equity securities:					
Domestic	—	3	—	—	3
International	10	—	—	—	10
Debt securities—Domestic government	—	5	—	—	5
Investments measured at NAV:					
Money market funds	—	—	—	4	4
Collective trust funds	—	—	—	8	8
	$ 13	$ 8	$ —	$ 12	$ 33

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

An overview of the identification of Level 1, 2, and 3 financial instruments is provided in Note 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 net asset value. These funds invest in high-quality, short-term, diversified money market instruments, short-term treasury bills, federal agency securities, or certificates of deposit. Some of the money market funds held in the trusts are classified as Level 1 instruments as pricing inputs are based on unadjusted prices in an active market. The remaining money market funds are valued at NAV as a practical expedient and are not classified in the fair value hierarchy.

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

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

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

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

The following tables provide certain information with respect to the Company's defined benefit pension plan, other postretirement benefits, and NQBP as of and for the years ended December 31, 2018 and 2017. Information related to the Other NQBP is not included in the following tables (dollars in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2018	2017	2018	2017	2018	2017
Benefit obligation:						
As of January 1	$ 869	$ 797	$ 78	$ 73	$ 27	$ 27
Service cost	19	17	2	2	—	—
Interest cost	32	33	3	3	1	1
Participants' contributions	—	—	2	2	—	—
Actuarial loss (gain)	(67)	60	(7)	3	(1)	1
Contractual termination benefits	—	—	—	1	—	—
Benefit payments	(39)	(36)	(6)	(6)	(3)	(2)
Administrative expenses	(3)	(2)	—	—	—	—
As of December 31	$ 811	$ 869	$ 72	$ 78	$ 24	$ 27
Fair value of plan assets:						
As of January 1	$ 629	$ 559	$ 33	$ 30	$ 17	$ 16
Actual return on plan assets	(50)	106	(2)	4	(1)	1
Company contributions	9	2	3	3	3	2
Participants' contributions	—	—	2	2	—	—
Benefit payments	(39)	(36)	(6)	(6)	(3)	(2)
Administrative expenses	(3)	(2)	—	—	—	—
As of December 31	$ 546	$ 629	$ 30	$ 33	$ 16	$ 17
Unfunded position as of December 31	$ (265)	$ (240)	$ (42)	$ (45)	$ (8)	$ (10)
Accumulated benefit plan obligation as of December 31	$ 734	$ 778	N/A	N/A	$ 24	$ 27
Classification in consolidated balance sheet:						
Noncurrent asset	$ —	$ —	$ —	$ —	$ 16	$ 17
Current liability	—	—	—	—	(2)	(2)
Noncurrent liability	(265)	(240)	(42)	(45)	(22)	(25)
Net liability	$ (265)	$ (240)	$ (42)	$ (45)	$ (8)	$ (10)
Amounts included in comprehensive income:						
Net actuarial loss (gain)	$ 25	$ (4)	$ (4)	$ —	$ (1)	$ 1
Amortization of net actuarial loss	(17)	(13)	—	—	(1)	(1)
	$ 8	$ (17)	$ (4)	$ —	$ (2)	$ —
Amounts included in AOCL*:						
Net actuarial loss (gain)	$ 226	$ 218	$ (4)	$ (1)	$ 11	$ 13
Prior service cost	—	—	—	—	—	—
	$ 226	$ 218	$ (4)	$ (1)	$ 11	$ 13

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2018	2017	2018	2017	2018	2017
Assumptions used:						
Discount rate for benefit obligation	4.25%	3.65%	4.10%-4.26%	3.42%-3.70%	4.25%	3.65%
Discount rate for benefit cost	3.65%	4.17%	3.42%-3.70%	3.75%-4.23%	3.65%	4.17%
Weighted average rate of compensation increase for benefit obligation	3.65%	3.65%	4.58%	4.58%	N/A	N/A
Weighted average rate of compensation increase for benefit cost	3.65%	3.65%	4.58%	4.58%	N/A	N/A
Long-term rate of return on plan assets for benefit cost	7.00%	7.50%	6.20%	6.26%	N/A	N/A

* Amounts included in AOCL related to the Company's defined benefit pension plan and other postretirement benefits are transferred to 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		
	2018	2017	2016	2018	2017	2016	2018	2017	2016
Service cost	$ 19	$ 17	$ 16	$ 2	$ 2	$ 2	$ —	$ —	$ —
Interest cost on benefit obligation	32	33	33	3	3	4	1	1	1
Expected return on plan assets	(42)	(42)	(40)	(1)	(2)	(2)	—	—	—
Amortization of prior service cost	—	—	—	—	—	1	—	—	—
Amortization of net actuarial loss	17	13	14	—	—	—	1	1	1
Net periodic benefit cost	$ 26	$ 21	$ 23	$ 4	$ 3	$ 5	$ 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 $11 million will be amortized from AOCL into net periodic benefit cost in 2019, consisting of a net actuarial loss of $10 million for pension benefits and $1 million for non-qualified benefits. Amounts related to the pension and other postretirement benefits are offset with the amortization of the corresponding regulatory asset.

The following table summarizes the benefits expected to be paid to participants in each of the next five years and in the aggregate for the five years thereafter (in millions):

	Payments Due					
	2019	2020	2021	2022	2023	2024 - 2028
Defined benefit pension plan	$ 41	$ 42	$ 44	$ 45	$ 45	$ 238
Other postretirement benefits	5	5	5	5	6	22
Non-qualified benefit plans	2	2	2	2	2	10
Total	$ 48	$ 49	$ 51	$ 52	$ 53	$ 270

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

For measurement purposes, the assumed health care cost trend rates, which can affect amounts reported for the health care plans, were as follows:

- For 2018, 6.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2019 and 2020, then decreasing 0.25% per year thereafter, reaching 5.0% in 2026;
- For 2017, 6.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2018, decreasing to 6.0% in 2019, then decreasing 0.25% per year thereafter, reaching 5.0% in 2023; and
- For 2016, 7% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2017, decreasing to 6.5% in 2018, 6.0% in 2019, then decreasing 0.25% per year thereafter, reaching 5.0% in 2023.

A one percentage point increase or decrease in the above health care cost assumption would have no material impact on total service or interest cost, or on the postretirement benefit obligation.

401(k) Retirement Savings Plan

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

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

All contributions are invested in accordance with employees' elections, limited to investment options available under the 401(k) Plan. PGE made contributions to employee accounts of $23 million in 2018, $21 million in 2017, and $19 million in 2016.

NOTE 12: 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. The most significant change to PGE's financial condition was the federal corporate tax rate decrease from 35% to 21%.

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.

The protected excess deferred income tax is amortized using the average rate assumption method and is included in the 2019 General Rate Case as a refund to customers.

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

	Years Ended December 31,		
	2018	2017	2016
Current:			
Federal	$ 12	$ 4	$ 10
State and local	22	12	3
	34	16	13
Deferred:			
Federal	(15)	61	23
State and local	(2)	9	14
	(17)	70	37
Income tax expense	$ 17	$ 86	$ 50

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

	Years Ended December 31,		
	2018	2017	2016
Federal statutory tax rate	21.0%	35.0%	35.0%
Federal tax credits (1)	(16.7)	(14.0)	(18.2)
Change in federal tax law (2)	—	6.1	—
State and local taxes, net of federal tax benefit	6.5	5.0	4.8
Flow through depreciation and cost basis differences	1.5	1.5	0.2
Excess deferred tax amortization (3)	(4.1)	—	—
Other	(0.8)	(2.1)	(1.2)
Effective tax rate	7.4%	31.5%	20.6%

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

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

(3) The majority of excess ADIT related to remeasurement under the TCJA is subject to 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, 2018	As of December 31, 2017
Deferred income tax assets:		
Employee benefits	$ 134	$ 128
Price risk management	36	56
Regulatory liabilities	26	14
Tax credits	52	50
Other	9	4
Total deferred income tax assets	257	252
Deferred income tax liabilities:		
Depreciation and amortization	511	496
Regulatory assets	115	132
Total deferred income tax liabilities	626	628
Deferred income tax liability, net	$ 369	$ 376

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

PGE and its subsidiaries file a 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 (based on fair value on the purchase date) or 1,500 shares, whichever is less. Two, six-month offering periods occur annually, January 1 through June 30 and July 1 through December 31, during which eligible employees may contribute toward the purchase of shares of PGE common stock. Purchases occur the last day of the offering period, at a price equal to 95% of the fair value of the stock on the purchase date. As of December 31, 2018, there were 306,175 shares available for future issuance pursuant to the ESPP.

Dividend Reinvestment and Direct Stock Purchase Plan

PGE has a Dividend Reinvestment and Direct Stock Purchase Plan (DRIP), under which a total of 2,500,000 shares of the Company's common stock may be issued. Under the DRIP, investors may elect to buy shares of the Company's common stock or elect to reinvest cash dividends in additional shares of the Company's common stock. As of December 31, 2018, there were 2,467,956 shares available for future issuance pursuant to the DRIP.

NOTE 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. Service requirements generally must be met for RSUs to vest. For each grant, the number of RSUs is determined by dividing the specified award amount for each grantee by the closing stock price on the date of grant. RSU activity is summarized in the following table:

	Units	Weighted Average Grant Date Fair Value
Outstanding as of December 31, 2015	442,993	$ 32.84
Granted	193,734	35.89
Forfeited	(3,044)	28.62
Vested	(174,891)	31.47
Outstanding as of December 31, 2016	458,792	34.68
Granted	202,145	41.96
Forfeited	(64,840)	39.57
Vested	(196,721)	31.78
Outstanding as of December 31, 2017	399,376	37.98
Granted	198,864	37.99
Forfeited	(8,556)	39.73
Vested	(160,771)	36.77
Outstanding as of December 31, 2018	428,913	38.43

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

Outstanding RSUs provide for the payment of one Dividend Equivalent Right (DER) for each stock unit. DERs represent an amount equal to dividends paid to shareholders on a share of PGE's common stock and vest on the same schedule as the RSUs. The DERs are settled in cash (for grants to non-employee directors) or shares of PGE common stock valued either at the closing stock price on the vesting date (for performance-based RSUs) or dividend payment date (for all other grants). The cash from the settlement of the DERs for non-employee directors may be deferred under the terms of the Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan.

Time-based RSUs vest in either equal installments over a one-year period on the last day of each calendar quarter, over a three-year period on each anniversary of the grant date, or at the end of a three-year period following the grant date. The fair value of time-based RSUs is measured based on the closing price of PGE common stock on the date of grant and charged to compensation expense on a straight-line basis over the requisite service period for the entire award. The total value of time-based RSUs vested was less than $1 million for the years ended December 31, 2018, 2017, and 2016.

Performance-based RSUs vest if performance goals are met at the end of a three-year performance period. Grants are based on three equally-weighted metrics: i) return on equity relative to allowed return on equity; ii) regulated asset base growth (applicable only for those grants made prior to 2017); and iii) a relative total shareholder return (TSR) of PGE's common stock as compared to an index of peer companies during the performance period. Vesting of performance-based RSUs is calculated by multiplying the number of units granted by a performance percentage determined by the Compensation and Human Resources Committee of PGE's Board of Directors (Committee). The performance percentage is calculated based on the extent to which the performance goals are met. In accordance with the Plan, however, the Committee may disregard or offset the effect of extraordinary, unusual or non-recurring items in determining results relative to these goals. Based on the attainment of the performance goals, the awards can range from zero to 150% of the grant.

For the return on equity and regulated asset base growth portions of the performance-based RSUs, fair value is measured based on the closing price of PGE common stock on the date of grant. For the TSR portion of the performance-based RSUs, fair value is determined using a Monte Carlo simulation model utilizing actual information for the common shares of PGE and its peer group for the period from the beginning of the performance period to the grant date and estimated future stock volatility over the remaining performance period. The fair value of stock-based compensation related to the TSR component of performance-based RSUs was determined using the Monte Carlo model and the following weighted average assumptions:

	2018		2017		2016	
Risk-free interest rate		2.4%		1.5%		0.9%
Expected dividend yield		—%		—%		—%
Expected term (in years)		3.0		3.0		3.0
Volatility	14.7% -	21.8%	15.6% -	22.9%	14.5% -	25.9%

The fair value of performance-based RSUs is charged to compensation expense on a straight-line basis over the requisite service period for the entire award based on the number of shares expected to vest. Stock-based compensation expense was calculated assuming the attainment of performance goals that would allow the weighted average vesting of 89.9%, 97.8%, and 106.6% of awarded performance-based RSUs for the respective 2018, 2017, and 2016 grants, with an estimated 5% forfeiture rate.

The total value of performance-based RSUs vested was $4 million for the year ended December 31, 2018, $6 million for 2017, and $5 million for 2016.

Stock-based compensation, included in Administrative and other expense in the consolidated statements of income, was $5 million for the year ended December 31, 2018, $7 million for 2017, and $6 million in 2016. 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 2018, and $3 million in 2017 and $2 million in 2016.

As of December 31, 2018, unrecognized stock-based compensation expense was $6 million, of which approximately $4 million and $2 million is expected to be expensed in 2019 and 2020, respectively. No stock-based compensation costs have been capitalized and the Plan had no material impact on cash flows for the years ended December 31, 2018, 2017, or 2016.

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 restricted stock units, along with associated dividend equivalent rights.

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

	Years Ended December 31,		
	2018	2017	2016
Weighted average common shares outstanding—basic	89,215	89,056	88,896
Dilutive effect of potential common shares	132	120	158
Weighted average common shares outstanding—diluted	89,347	89,176	89,054

NOTE 16: COMMITMENTS AND GUARANTEES

Purchase Commitments

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

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

Capital and other purchase commitments—Certain commitments have been made for 2019 and beyond that include those related to hydro licenses, upgrades to generation, distribution, and transmission facilities, information systems, and system maintenance work. Termination of these agreements could result in cancellation charges.

Electricity purchases and Capacity contracts—PGE has power purchase agreements with counterparties, which expire at varying dates through 2041, and power capacity contracts through 2028.

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

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

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

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

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

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

Natural gas—PGE has contracts for the purchase and transportation of natural gas from domestic and Canadian sources for its natural gas-fired generating facilities. The Company also has a natural gas storage agreement for the purpose of fueling the Company's Port Westward Unit 1 (PW1), PW2, and Beaver natural gas-fired generating plants.

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

Lease Obligations

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

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

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

As of December 31, 2018, a capital lease asset of $57 million was reflected within 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 and 2017.

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

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

Operating leases—PGE has various operating leases associated with leases of land, support facilities, and power purchase agreements that rely on identified plant that expire in various years, extending through 2096. Rent expense was $7 million in 2018, $9 million in 2017, and $10 million in 2016. Contingent rents related to power purchase agreements was $14 million in 2018.

Sublease income was $4 million in 2018, 2017, and 2016.

Guarantees

PGE enters into financial agreements and power and natural gas purchase and sale agreements that include indemnification provisions relating to certain claims or liabilities that may arise relating to the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. PGE periodically evaluates the likelihood of incurring costs under such indemnities based on the Company's historical experience and the evaluation of the specific indemnities. As of December 31, 2018, management believes the likelihood is remote that PGE would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnities. The Company has not recorded any liability on the consolidated balance sheets with respect to these indemnities.

NOTE 17: JOINTLY-OWNED PLANT

As of December 31, 2018, 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	$ 516	$ 451	$ —
Colstrip	20.00	1986	549	363	10
Pelton/Round Butte	66.67	1958 / 1964	270	73	2
Total			$ 1,335	$ 887	$ 12

* Excludes AROs and accumulated asset retirement removal costs.

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

NOTE 18: 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.

Carty

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

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

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

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

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

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

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

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

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

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

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

EPA Investigation of Portland Harbor

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

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

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

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

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

In cases in which injuries to natural resources have occurred as a result of releases of hazardous substances, federal and state natural resource trustees may seek to recover for damages at such sites, which are referred to as Natural Resource Damages (NRD). The EPA does not manage NRD assessment activities but does provide claims information and coordination support to the NRD trustees. NRD assessment activities are typically conducted by a Council made up of the trustee entities for the site. The Portland Harbor NRD trustees are the National Oceanic and Atmospheric Administration, the U.S. Fish and Wildlife Service, the State of Oregon, and certain tribal entities.

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

Significant uncertainties still remain concerning the precise boundaries for clean-up, the assignment of responsibility for clean-up costs, the final selection of a proposed remedy by the EPA, and the method of allocation of costs amongst PRPs. It is probable that PGE will share in a portion of these costs. However, the Company does not currently have sufficient information to reasonably estimate the amount, or range, of its potential costs for investigation or remediation of Portland Harbor, although such costs could be material to PGE's financial position.

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

Trojan Investment Recovery Class Actions

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

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

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

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

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

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

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

Deschutes River Alliance Clean Water Act Claims

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

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

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

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

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

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

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

Other Matters

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

QUARTERLY FINANCIAL DATA

(Unaudited)

	Quarter Ended			
	March 31	**June 30**	**September 30**	**December 31**
	(In millions, except per share amounts)			
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
2017				
Revenues, net	$ 530	$ 449	$ 515	$ 515
Income from operations	123	68	77	112
Net income	73	32	40	42
Earnings per share:*				
Basic	0.82	0.36	0.44	0.48
Diluted	0.82	0.36	0.44	0.48

* 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, 2018, the Company’s internal control over financial reporting is effective.

The Company’s internal control over financial reporting, as of December 31, 2018, 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, 2018.

(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 2018 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION.

Resignation of Director

At a regularly scheduled meeting of the Board of Directors 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. Pursuant to Section 3.2 of the Company’s bylaws, the board reduced the number of directors from twelve to eleven, effective upon such election of directors.

Adoption of Amended and Restated Bylaws

Effective February 13, 2019, the Board of Directors amended and restated the Company’s bylaws to:

- Permit the Company to hold virtual shareholder meetings (Section 2.3);
- Establish a process for setting a record date for determining shareholders entitled to take corporate action without a meeting (Section 2.6);
- Establish a deadline for shareholders seeking to take action without a meeting to deliver the requisite number of written shareholder consents to the Company (Section 2.15);
- Update and enhance our advance notice bylaws by, among other things, expanding the scope of disclosures required of a shareholder seeking to bring a nomination or propose other business for consideration at a meeting of shareholders (Sections 2.13 and 2.14); and
- Provide for certain other technical or minor updates and revisions.

The foregoing summary is qualified in its entirety by reference to the full text of the Company's Eleventh Amended and Restated Bylaws, a copy of which is included as Exhibit 3.2 to this Annual Report on Form 10-K and incorporated by reference herein.

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 "Section 16(a) Beneficial Ownership Reporting Compliance," "Corporate Governance," and "Proposal 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 24, 2019. 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—Non-Employee Director Compensation," "Corporate Governance—Compensation Committee Interlocks and Insider Participation," "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 24, 2019.

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" and "Equity Compensation Plans," 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 24, 2019.

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 24, 2019.

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 24, 2019.

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.
(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).
(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.
10.4*	Consent Agreement, dated November 3, 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). +
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). +

Exhibit Number	Description
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 (Form 8-K filed July 14, 2006, Exhibit 10.1) (File No. 001-05532-99). +
10.19*	Form of Officers' and Key Employees' Performance Stock Unit Agreement (Form 10-Q filed May 3, 2012, Exhibit 10.1) (File No. 001-05532-99). +
(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.
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.

* 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 14, 2019.

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 14, 2019.

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/ DAVID A. DIETZLER **David A. Dietzler**	*Director*
/s/ KIRBY A. DYESS **Kirby A. Dyess**	*Director*
/s/ MARK B. GANZ **Mark B. Ganz**	*Director*
/s/ KATHRYN J. JACKSON **Kathryn J. Jackson**	*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. 333-214580 on Form S-3 and Registration Statements Nos. 333-135726, 333-142694, and 333-158059 on Forms S-8 of our report dated February 14, 2019, 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, 2018.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 14, 2019

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 14, 2019

/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 14, 2019

/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, 2018, as filed with the Securities and Exchange Commission on February 15, 2019 pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the “Report”), fully complies with the requirements of that section.

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

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

Date: February 14, 2019

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

Date: February 14, 2019

Corporate information

BOARD OF DIRECTORS

Jack E. Davis
Chairman 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

David A. Dietzler
Retired Pacific Northwest Partner in
Charge of Audit Practice, KPMG LLP

Kirby A. Dyess
Principal,
Austin Capital Management LLC

Mark B. Ganz
President and Chief Executive Officer,
Cambia Health Solutions, 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

Anne F. Mersereau
Vice President,
Human Resources,
Diversity, Equity and Inclusion

William O. Nicholson
Vice President,
Utility Technical Services

W. David Robertson
Vice President,
Public Policy

Kristin A. Stathis
Vice President,
Customer Solutions

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
111 SW Fifth Ave., Ste. 3900
Portland, OR 97204
503-222-1341

Form 10-K
A copy of the company's 2018 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

2018 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. As a result, we are adopting the Edison Electric Institute's ESG reporting framework for sharing these metrics. Look for our first ESG report in the second half of 2019.

ENVIRONMENT

No. 1

Renewables program in the country for the ninth straight year, surpassing 200,000 customers — the equivalent of taking 1.7 million cars off the road for one year

40 percent

PGE's energy that is carbon free as we work to reduce greenhouse gas emissions by 80 percent by 2050

42 MW

New renewable resources added to our portfolio from 12 solar and biomass facilities

507,635 miles

Powered in 2018 by the Electric Avenue at PGE headquarters, avoiding about 205 metric tons of CO_2 emissions compared to the average light duty, gas-powered vehicle

SOCIAL

$3.1 million
Donated to more than 1,200 community organizations by PGE and the PGE Foundation

$1.9 million
Raised in our Employee Giving Campaign, including the company match

45,923
Hours volunteered by employees and retirees in communities statewide

$155,000
Contributed to 53 Career Technical Education (CTE) scholarships in Science, Technology, Engineering and Math (STEM)

74,640
Children received PGE-sponsored safety and energy education — more than 43 percent of students in PGE service area

1,100
Business, government and community thought leaders joined us for the seventh PGE Diversity Summit

GOVERNANCE

First
Electric Power Research Institute Technology Transfer Award for completing and applying a new sustainability maturity model to our greenhouse gas emissions strategy, governance and work

First
Inclusion in Bloomberg's 2019 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, Ore.

INSIDE SHAREHOLDER LETTER

Maria Pope, PGE President and Chief Executive Officer

INSIDE 2018 HIGHLIGHTS (LEFT)

Our Biglow Canyon Wind Farm

INSIDE 2018 HIGHLIGHTS (RIGHT)

John Kochavatr, PGE's Information Technology and Chief Information Officer and employees Barbara Gustafson and Brandy Dickman join SOLVE volunteers to help keep the Rose Festival clean and green

Employee Nhien Le teaching kids about safety and energy at one of our Summer of Safety events

Shiza Shahid, co-founder of the Malala Fund and NOW Ventures, Keynote Speaker at our 2018 Diversity Summit