PORTLAND GENERAL ELECTRIC CO /OR/
Form 10-K
February 15, 2019

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

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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

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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.

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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

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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.

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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 ¢

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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.

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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."

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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.

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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

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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.

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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.”

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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.

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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."

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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

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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

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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.

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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.

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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 i to identify such forward-looking statements.

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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.

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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:

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	2018 Average Number of Customers	Energy Deliveries *	2017 Average Number of Customers	Energy Deliveries *	Increase/ (Decrease) in 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

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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;

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- 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

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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.

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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.

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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.

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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					