Portland General Electric Company

2013 ANNUAL REPORT

Portland General Electric

To Our Shareholders | Portland General Electric continues to deliver value to our stakeholders through our mission of powering our customers' potential as the region's trusted energy partner.

2013 was a big year for PGE: We entered into agreements for three new long-term generation resources that will help us deliver a sustainable, affordable energy future; we worked with our regulators and stakeholders to establish new customer prices; and we maintained high customer satisfaction ratings in all classes, including top decile in overall system reliability with large customers, according to national research. These company achievements demonstrate our employees' commitment to our core business strategy and creation of value for all our stakeholders.

Operational Excellence

2013 was a strong year in overall operational performance. Our distribution system operated with high reliability, and despite outages at Boardman and Coyote Springs, generation availability at PGE-operated plants was on target. PGE continues to make improvements across the company to be more efficient and cost effective and improve our employees' safety through targeted programs.

For 2013, PGE delivered net income of $105 million, or $1.35 per diluted share, for a 5.9 percent return on equity. Our strong operational performance was impacted by the termination of the Cascade Crossing Transmission Project, a customer billing refund, and incremental replacement power costs due to plant outages in the second half of 2013.

We made the decision to discontinue our work on the Cascade Crossing Transmission Project when we determined that, as a result of a change in regional demand driven by limitations on renewable exports to California, the project was no longer the best alternative for our customers. We are confident this was the correct decision given current conditions.

Weather-adjusted energy deliveries in 2013 were comparable to the previous year. In 2014, we anticipate an overall increase of about 1 percent, attributed to industrial customers as demand from the high-tech sector is expected to increase.

In 2013, PGE filed a general rate case, our first since 2010. We received approval from the Oregon Public Utility Commission to increase base customer prices by approximately 4 percent beginning Jan. 1, 2014, with a revenue requirement based on a 9.75 percent allowed return on equity. With two of the three new generation projects expected to begin serving customers in the first half of 2015, PGE initiated a new general rate case in 2014 requesting the commission approve an overall price increase of 4.6 percent, effective early 2015.

We continue to invest in our business with capital expenditures of $656 million in 2013. These investments included expenditures related to the three new generation projects, a new emergency readiness center, and continued investments in our transmission and distribution system to build capacity, increase reliability and improve power quality for customers. PGE continues to maintain strong overall credit quality, which supports our ability to finance ongoing investments. At year-end, our equity-to-total capital ratio was 49 percent, and our investment-grade credit ratings for secured debt were A– and A1 by Standard & Poor's and Moody's, respectively, which keeps our financing costs low for customers.

Business Growth

Construction is underway on all three generation projects selected last year through the competitive bidding processes, and each of these projects continues to be on time and on budget. We are building Port Westward Unit 2, a 220 MW natural gas capacity plant next to our existing Port Westward plant in Clatskanie, Ore., and it is expected to come online in the first quarter of 2015. Tucannon River Wind Farm is expected to come fully online in the first half of 2015, with nameplate capacity of 267 MW. Carty Generating Station, a 440 MW natural gas-fired plant, is being constructed next to our existing Boardman plant and is expected to become operational in mid-2016. The three new plants will be owned and operated by PGE for a cumulative investment during four years of $1.25 billion.

Looking Forward

In 2014, we are focused on continually emphasizing operational excellence and the construction of three new generation resources on time and on budget.

Corporate Responsibility

We continue to work with businesses, community leaders and local governments to support the economic growth of our region — because the region's success is our success. I am especially proud of our employees' continued commitment to the communities in which we live and serve. For the sixth year in a row, PGE employees and retirees pledged more than $1 million for charitable causes, benefiting more than 950 nonprofits and schools. PGE employees also logged more than 35,000 hours of volunteer time in our communities in 2013.

I am proud of the hard work and achievements that took place in all corners of the company in 2013. Our employees' commitment and dedication to serving our customers is the key to our success. Together with my co-workers, we will continue our efforts in 2014 to provide safe, reliable, sustainable power for Oregon's energy future, which will deliver value to our customers, shareholders, and the communities we serve.

Sincerely,

Jim Piro

Jim Piro | President and Chief Executive Officer

Financial Highlights

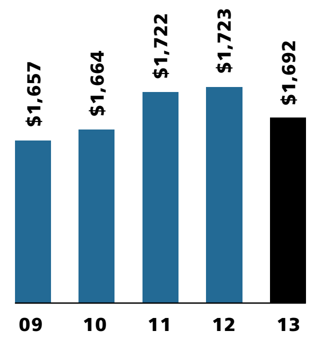
About Portland General Electric

Portland General Electric Company, headquartered in Portland, Ore., is a fully integrated electric utility serving approximately 836,000 residential, commercial and industrial customers in Oregon. PGE common stock is traded on the New York Stock Exchange under the ticker symbol POR.

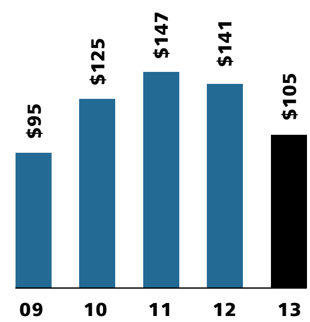
(Dollars in millions, except per share amounts)	**2013**	**2012**	**2011**
Operating revenues	$1,810	$1,805	$1,813
Net operating income	$206	$302	$309
Net income for common stock	$105	$141	$147
Return on average quarter-end equity	5.9%	8.2%	9.0%
Total assets	$6,101	$5,670	$5,733
Dividends declared per common share	$1.095	$1.075	$1.055
Weighted-average shares outstanding (in thousands), diluted	77,388	75,647	75,350
Customers	836,070	828,354	822,466
Long-term debt, including current portion	$1,916	$1,636	$1,735
Long-term debt/capitalization	51.3%	48.4%	50.6%
Senior secured debt ratings (S&P/Moody's)	A-/A1	A-/A3	A-/A3
Commercial paper ratings (S&P/Moody's)	A-2/P-2	A-2/P-2	A-2/P-2
Employees	2,596	2,603	2,634

Stock Performance Graph

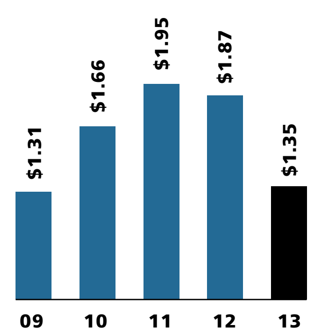
1. Assumes a $100 investment in Portland General Electric's common stock and each index on December 31, 2008, and that all dividends were reinvested.



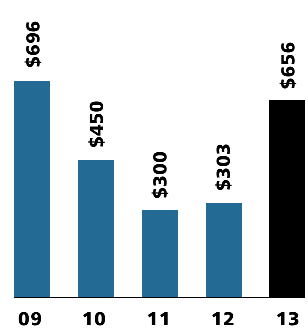
TOTAL RETAIL REVENUE



NET INCOME



EARNINGS PER SHARE (DILUTED)



CAPITAL EXPENDITURES

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, 2013

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 and posted on its corporate Website, if any, every Interactive Date File required to be submitted and posted 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 and post 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, or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	[x]	Accelerated filer	[ ]
Non-accelerated filer	[ ]	Smaller reporting company	[ ]

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 28, 2013, the aggregate market value of voting common stock held by non-affiliates of the Registrant was $2,358,020,964. For purposes of this calculation, executive officers and directors are considered affiliates.

As of February 10, 2014, there were 78,086,174 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 May 7, 2014.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2013

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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
CAA	Clean Air Act
Carty	Carty Generating Station 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
CWIP	Construction work-in-progress
Dth	Decatherm = 10 therms = 1,000 cubic feet of natural gas
DEQ	Oregon Department of Environmental Quality
EFSA	Equity forward sale agreement
EPA	United States Environmental Protection Agency
ESS	Electricity Service Supplier
FERC	Federal Energy Regulatory Commission
FMB	First Mortgage Bond
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
Port Westward	Port Westward natural gas-fired generating plant
PW2	Port Westward Unit 2 natural gas-fired generating plant
RPS	Renewable Portfolio Standard
S&P	Standard & Poor's Ratings Services
SEC	United States Securities and Exchange Commission
Trojan	Trojan nuclear power plant
Tucannon River	Tucannon River Wind Farm
USDOE	United States Department of Energy
VIE	Variable interest entity

PART I

ITEM 1. BUSINESS.

General

Portland General Electric Company (PGE or the Company) is a vertically integrated electric utility engaged in the generation, 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's retail load requirement is met with both Company-owned generation and power purchased in the wholesale market. The Company also participates in the wholesale market by purchasing and selling electricity and natural gas in an effort to obtain reasonably-priced power for its retail customers. PGE was incorporated in 1930, is publicly-owned, with its common stock listed on the New York Stock Exchange, and operates as a single 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 52 incorporated cities, of which Portland and Salem are the largest. The Company estimates that at the end of 2013 its service area population was 1.7 million, comprising approximately 44% of the state's population. During 2013, the Company added 7,716 customers and as of December 31, 2013, served a total of 836,070 retail customers.

PGE had 2,596 employees as of December 31, 2013, with 795 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 760 and 35 employees and expire in February 2015 and August 2014, 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 Internet 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 Internet website at sec.gov.

Regulation

PGE is subject to both federal and state regulation, which can have a significant impact on the operations of the Company. In addition to those 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

PGE is subject to regulation by 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).

FERC Regulation

The Company is a "licensee," a "public utility," and a "user, owner and operator of the bulk power system," as defined in the Federal Power Act, and 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. Re-authorization for continued use of such rates requires the filing of triennial market power studies with the FERC. The Company filed an updated triennial market power study in June 2013 and is awaiting an Order from the FERC.

Transmission—PGE offers transmission service pursuant to its Open Access Transmission Tariff (OATT), which is filed with the FERC. As required by the OATT, PGE provides information regarding its transmission business on its Open Access Same-time Information System, also known as OASIS. As of December 31, 2013, PGE owned 1,141 circuit miles of transmission lines. For additional information, see the Transmission and Distribution section in this Item 1. and in Item 2.—"Properties."

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 (CIP) 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.

Pipeline—The Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 provide the FERC authority in matters related to the extension, enlargement, safety, and abandonment of jurisdictional 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 and is the operator of record of the Kelso-Beaver Pipeline, a 17-mile interstate pipeline that provides natural gas to the Company's Port Westward natural gas-fired generating plant (Port Westward) and Beaver natural gas-fired generating plant (Beaver). As the operator of record, 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 Federal Power Act, PGE's hydroelectric generating plants are subject to FERC licensing requirements. These include an extensive public review process that involves the consideration of numerous natural resource issues and environmental conditions. PGE holds FERC licenses for the Company's projects on the Deschutes, Clackamas, and Willamette Rivers. For additional information, see the Environmental Matters section in this Item 1. and Generating Facilities section in Item 2.—"Properties."

Accounting Policies and Practices—Pursuant to applicable provisions of the Federal Power Act, 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 Federal Power Act and FERC regulations, regulated public utilities are required to obtain FERC approval to issue certain securities. The Company, pursuant to an order issued by the FERC on February 3, 2014, is authorized to issue up to $900 million of short-term debt through February 6, 2016.

NRC Regulation

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 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 7, 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, which is comprised of three members appointed by Oregon's governor to serve non-concurrent four-year terms.

The OPUC reviews and approves the Company's retail prices (see "*Ratemaking*" below) and establishes conditions of utility service. In addition, the OPUC reviews the Company's generation and transmission resource acquisition plans, pursuant to an integrated resource planning process. The OPUC also regulates the issuance of securities, prescribes accounting policies and practices, and reviews both applications to sell utility assets and engage in transactions with affiliated companies and applications to acquire substantial influence over a public utility.

Oregon's Energy Facility Siting Council (EFSC) has regulatory and siting responsibility for large electric generating facilities, high voltage transmission lines, intrastate gas pipelines, and radioactive waste disposal sites. The EFSC also has responsibility for overseeing the decommissioning of Trojan. The seven volunteer members of the EFSC are appointed to four-year terms by Oregon's governor, with staff support provided by the Oregon Department of Energy.

Integrated Resource Plan—Unless the OPUC directs otherwise, PGE is required to file with the OPUC an Integrated Resource Plan (IRP) within two years of its previous IRP acknowledgment order. Based on direction from the OPUC, PGE is required to file its next IRP by the end of March 2014. The IRP guides the utility on how it will meet future customer demand and describes the Company's future energy supply strategy, reflecting new technologies, market conditions, and regulatory requirements. The primary goal of the IRP is to identify an acquisition plan for generation, transmission, demand-side and energy efficiency resources that, along with the Company's existing portfolio, provides the best combination of expected cost and associated risks and uncertainties for PGE and its customers. For additional information on PGE's most recent IRP, see "*Future Energy Resource Strategy*" in the Power Supply section in this Item 1.

Economic Regulation—Under Oregon law, the OPUC is required to ensure that prices and terms of service are fair, non-discriminatory, and 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, include PGE, OPUC staff, and intervenors representing PGE customer groups. 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. Such changes are requested pursuant to a comprehensive general rate case process that includes revenue requirements based on a forecasted test year, debt-to-equity capital structure, return on equity, and overall rate of return. PGE's most recent general rate case was the 2014 General Rate Case, which became effective on January 1, 2014. On February 13, 2014, PGE filed a general rate case with a 2015 test year (2015 General Rate Case), for which a final order is expected to be received in December 2014. New prices are expected to be effective in 2015, with the first price increase effective January 1 and two additional price increases effective as two new generating plants become operational, which is expected in the first half of 2015. For additional information, see 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 the following mechanisms by which PGE can adjust retail customer prices to cover the Company's Net Variable Power Costs (NVPC), which consist of the cost of purchased power and fuel used in generation (including related transportation costs) less revenues from wholesale power and fuel sales:
    - Annual Power Cost Update Tariff (AUT). Under this tariff, customer prices are adjusted annually to reflect the latest forecast of NVPC. Such forecasts assume the following for the different types of PGE-owned generating resources;
        - Thermal—expected operating conditions;
        - Hydroelectric—Average regional hydro conditions (based on seventy years of stream flow data covering the period 1928 - 1998) and current hydro operating parameters; and
        - Wind—Average wind conditions 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 will be based on wind studies developed prior to the operation of the facility.

      An initial NVPC forecast, submitted to the OPUC by April 1st each year, is updated during such year and finalized in November of the same year. Based upon the final forecast, new prices, as approved by the OPUC, become effective at the beginning of the next calendar year; and
    - Power Cost Adjustment Mechanism (PCAM). Customer prices can also be adjusted to reflect a portion of the difference between each year's forecasted NVPC included in prices (baseline NVPC) and actual NVPC for the year. Under the PCAM, PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and baseline NVPC. The PCAM utilizes an asymmetrical deadband range within which PGE absorbs cost variances, with a 90/10 sharing of such variances between customers and the Company outside of the deadband. The deadband range is $15 million below, to $30 million above, baseline NVPC. Annual results of the PCAM are subject to application of a regulated earnings test, under which a refund will occur only to the extent that it results in PGE's actual regulated return on equity (ROE) for that year being no less than 1% above the Company's latest authorized ROE. A collection will occur only to the extent that it results in PGE's actual regulated ROE for that year being no greater than 1% below the Company's authorized ROE. A final determination of any customer refund or collection is made by the OPUC through a public filing and review typically during the second half of the following year. For additional information, see the Results of Operations section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."
- *Renewable Energy.* The 2007 Oregon Renewable Energy Act (the Act) established a Renewable Portfolio Standard (RPS) which requires that PGE serve at least 5% of its retail load with renewable resources by 2011, 15% by 2015, 20% by 2020, and 25% by 2025. PGE met the 2011 requirement and expects to have sufficient resources to meet the 2015 requirements with the Tucannon River Wind Farm (Tucannon River), which is expected to become operational in the first half of 2015.

  The Act also allows Renewable Energy Credits, resulting from energy generated from qualified renewable resources placed in service after January 1, 1995 and certified low impact hydroelectric power resources, to be used to meet the Company's RPS compliance obligation.

  The Act also provides for the recovery in customer prices of all prudently incurred costs required to comply with the RPS. Under a renewable adjustment clause (RAC) mechanism, PGE can recover the revenue requirement of new renewable resources and associated transmission that are not yet included in prices. Under the RAC, PGE submits a filing by April 1st of each year for new renewable resources expected to be placed in service in the current year, with prices to become effective January 1st of the following year. In addition, the RAC provides for the deferral and subsequent recovery of eligible costs incurred prior to January 1st of the following year.

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."

As needed, other ratemaking proceedings 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.

Retail Customer Choice Program—PGE's commercial and industrial customers have access to pricing options other than cost-of-service, including direct access and daily market index-based pricing. All commercial and industrial customers are eligible for direct access, whereby customers purchase their electricity from an Electricity Service Supplier (ESS), and the Company continues to deliver the energy to the customers. Large commercial and industrial customers may elect to be served by PGE on a daily market index-based price. Certain large commercial and industrial customers may elect to be removed from cost-of-service pricing for a fixed three-year or a minimum five-year term, to be served either by an ESS or the Company under a daily market index-based price. Participation in the fixed three-year and minimum five-year opt-out programs is capped at, in aggregate, 300 average megawatts (MWa).

The majority of the energy supplied under PGE's Retail Customer Choice program is provided to customers that have elected service from an ESS under the minimum five-year opt-out program. In 2013, ESSs supplied direct access customers with a total retail load representing 8% of the Company's total retail energy deliveries for the year, with 6% in 2012. The maximum retail load allowed to be supplied under the fixed three-year and minimum five-year opt-out programs would represent approximately 14% of the Company's total retail energy deliveries for 2013 and 2012.

The retail customer choice program has no material impact on the Company's financial condition or operating results. Revenue changes resulting from increases or decreases in electricity sales to direct access customers are substantially offset by changes in the Company's cost of purchased power and fuel. Further, the program provides for "transition adjustment" charges or credits to direct access and market based pricing customers that reflect the above- or below-market cost of energy resources owned or purchased by the Company. Such adjustments are designed 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.

In addition to cost-of-service pricing, residential and small commercial customers can select portfolio options from PGE that include time-of-use and renewable resource pricing.

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. Approximately $48 million, $50 million and $51 million was collected from customers for this charge in 2013, 2012 and 2011, respectively.

In addition to the public purpose charge, PGE also remits to the ETO amounts collected under an Energy Efficiency Adjustment tariff to fund additional energy efficiency measures. This charge was approximately 3.5%, 2.7% and 1.8% of retail revenues for applicable customers in 2013, 2012 and 2011, respectively. Under the tariff, approximately $50 million, $41 million and $28 million was collected from eligible customers in 2013, 2012 and 2011, respectively.

Decoupling—The decoupling mechanism, authorized through 2016, 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 by residential and certain commercial customers. The mechanism provides for collections from customers if weather adjusted use per customer is lower than levels included in the Company's most recent general rate case; it also provides for customer refunds if weather adjusted use per customer exceeds levels included in the most recent general rate case. The following is a summary of the impacts of the decoupling mechanism for the last three years:

- In 2013, PGE recorded an estimated collection of $5 million, of which $2 million related to an update for 2012. Pending review and approval by the OPUC, any resulting collection from customers would be expected over a one-year period beginning January 1, 2015.
- In 2012, the Company originally recorded an estimated refund of $1 million. After review in 2013, the OPUC ultimately approved a collection of $1 million, which is included in customer prices over a one-year period that began June 1, 2013.
- In 2011, PGE recorded an estimated refund of $2 million. The OPUC approved refunds to customers over a one-year period that began June 1, 2012.

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 reduce expense can be deferred as regulatory liabilities, based on expected future credits or refunds to customers. PGE records regulatory assets or liabilities if it is probable that they will be reflected in future prices, based on regulatory orders or other available evidence.

The Company periodically assesses the applicability of regulatory accounting to its business, considering both the current and anticipated future rate environment and related accounting guidance. For additional information, see "*Regulatory Assets and Liabilities*" in Note 2, Summary of Significant Accounting Policies, and Note 6, 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 through the sale and delivery of electricity to retail customers. The Company conducts retail electric operations exclusively in Oregon within a service area approved by the OPUC. Within its service territory, the Company 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. In addition, the Company distributes power to commercial and industrial customers that choose to purchase their energy supply from an ESS. The Company includes such "direct access" customers in its customer counts and energy delivered to such customers in its total retail energy deliveries, as reflected in the tables below. Retail revenues include only delivery charges and transition adjustments for these customers.

Retail Revenues

Retail customers are classified as residential, commercial, or industrial, with no single customer representing more than 4% of PGE's total retail revenues or 6% of total retail deliveries. While the 20 largest commercial and industrial customers constituted 12% of total retail revenues in 2013, they represented nine different groups including high technology, paper manufacturing, metal fabrication, health services, and governmental agencies.

PGE's Retail revenues (dollars in millions), retail energy deliveries (MWh in thousands), and average number of retail customers consist of the following for the years presented:

	Years Ended December 31,					
	2013		2012		2011	
Retail revenues[1] (dollars in millions):						
Residential	$ 861	51%	$ 860	50%	$ 877	51%
Commercial	619	36	633	37	635	37
Industrial	217	13	226	13	226	13
Subtotal	1,697	100	1,719	100	1,738	101
Other accrued (deferred) revenues, net	(5)	—	4	—	(16)	(1)
Total retail revenues	$ 1,692	100%	$ 1,723	100%	$ 1,722	100%
Retail energy deliveries[2] (MWh in thousands):						
Residential	7,702	40%	7,505	39%	7,733	40%
Commercial	7,441	38	7,402	39	7,419	38
Industrial	4,276	22	4,283	22	4,193	22
Total retail energy deliveries	19,419	100%	19,190	100%	19,345	100%
Average number of retail customers:						
Residential	728,481	87%	723,440	87%	719,977	87%
Commercial	104,385	13	103,766	13	102,940	13
Industrial	263	—	261	—	255	—
Total	833,129	100%	827,467	100%	823,172	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) 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,		
	2013	2012	2011
Usage per customer (in kilowatt hours):			
Residential	10,572	10,375	10,740
Commercial	71,284	71,343	72,075
Industrial	16,257,517	16,409,211	16,572,913
Revenue per customer (in dollars):			
Residential	$ 1,106	$ 1,113	$ 1,160
Commercial	5,840	6,041	6,194
Industrial	786,390	863,402	900,805
Revenue per kilowatt hour (in cents):			
Residential	10.46¢	10.72¢	10.80¢
Commercial	8.19	8.47	8.59
Industrial	4.84	5.26	5.44

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; although, increased use of air conditioning in PGE's service territory has caused the summer peaks to increase in recent years. Economic conditions can also affect residential demand, as historical data suggests that high unemployment rates contribute to a decrease in residential deliveries. 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 2013, as a result of cooler weather during the 2013 heating season and an increase in the average number of customers, total residential deliveries increased 2.6% compared to 2012. While the number of residential customers increased during 2012, total residential deliveries decreased 2.9% compared to 2011 driven by warmer weather conditions during the 2012 heating season. On a weather adjusted basis, energy deliveries to residential customers increased by 1% in 2013 when compared to 2012.

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.

Demand from the Company's commercial customers is somewhat less susceptible to weather conditions than the residential class, although weather does have an effect on commercial demand. Economic conditions and fluctuations in total employment in the region can also lead to corresponding changes in energy demand from commercial customers. Commercial demand is also impacted by energy efficiency measures, the financial effects of which are partially mitigated by the Company's decoupling mechanism.

In 2013, the favorable weather effects and an increase in the average number of customers contributed to the 0.5% increase in commercial deliveries compared with 2012. In 2012, deliveries to commercial customers decreased

0.2% compared with 2011, which was primarily due to unfavorable weather effects relative to 2011, and largely offset by the addition of an average of over 800 new customers.

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.

A change in economic activity can lead to a change in energy demand from the Company's industrial customers. The Company's industrial energy deliveries decreased 0.2% in 2013 from 2012 and increased 2.1% in 2012 from 2011, driven primarily by changes in demand from certain paper production customers.

Other accrued (deferred) revenues, net includes items that are not currently in customer prices, but are expected to be in prices in a future period. Such amounts include deferrals recorded under the RAC, the PCAM, and the decoupling mechanism. For further information on these items, see "*State of Oregon Regulation*" in the Regulation section of this Item 1.

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 conditions, and daily and seasonal retail demand. Wholesale revenues represented 4% of total revenues in 2013 and 3% in 2012 and 2011.

The majority of PGE's wholesale electricity sales are to utilities and power marketers and are predominantly short-term. The Company may net 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 excess natural gas, as well as revenues from transmission services, excess transmission capacity resales, excess fuel oil sales, pole contact rentals, and other electric services provided to customers. Other operating revenues represented 2% of total revenues in 2013, 2012, and 2011.

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 heating or cooling.

The following table indicates 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
2013	4,386	539
2012	4,169	436
2011	4,650	362
15-year average for 2013	4,239	454

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 3,949 MW occurred in July 2009. The following table presents the Company's average winter (consisting of January, February and December) and summer (consisting of July, August and September) loads for the periods indicated along with the corresponding peak load and month in which it occurred (in MWs):

	Winter Loads			Summer Loads		
	Average	**Peak**	**Month**	**Average**	**Peak**	**Month**
2013	2,656	3,869	December	2,278	3,527	July
2012	2,529	3,426	January	2,249	3,597	August
2011	2,612	3,555	January	2,233	3,340	September

The Company tracks and evaluates both load growth and peak load requirements for purposes of long-term load forecasting and integrated resource planning, as well as for 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 short- and long-term power and fuel purchase contracts to meet its customers' energy requirements. The Company executes economic dispatch decisions concerning its own generation, and participates in the wholesale market as a result of those economic dispatch decisions, 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 five thermal plants (natural gas- and coal-fired turbines), seven hydroelectric plants, and a wind farm located at Biglow Canyon in eastern Oregon. The volume of electricity the Company generates is dependent upon, among other factors, the capacity and availability of its generating resources. Capacity of the thermal plants represents the MW the plant is capable of generating under normal operating conditions, net of electricity used in the operation of the plant. The capacity of the Company's thermal generating resources is also affected by ambient temperatures. Capacity of both hydro and wind generating resources represent the nameplate MW, which varies from actual energy expected to be received as these types of generating resources are highly dependent upon river flows and wind conditions, respectively. Availability represents the percentage of the year the plant was available for operations, which reflects the impact of planned and forced outages. For a complete listing of these facilities, see "*Generating Facilities*" in Item 2.—"Properties."

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

	As of December 31,					
	2013		2012		2011	
	Capacity	%	Capacity	%	Capacity	%
Generation:						
Thermal:						
Natural gas	1,163	27%	1,172	28%	1,172	28%
Coal	756	17	670	16	670	16
Total thermal	1,919	44	1,842	44	1,842	44
Hydro (1)	501	11	489	12	489	12
Wind (2)	450	10	450	11	450	11
Total generation	2,870	65	2,781	67	2,781	67
Purchased power:						
Long-term contracts:						
Capacity/exchange	160	3	160	4	190	4
Hydro	603	14	588	14	579	14
Wind	39	1	39	1	38	1
Solar	13	—	13	—	6	—
Other	117	3	117	3	110	3
Total long-term contracts	932	21	917	22	923	22
Short-term contracts	596	14	475	11	458	11
Total purchased power	1,528	35	1,392	33	1,381	33
Total resource capacity	4,398	100%	4,173	100%	4,162	100%

(1) Capacity represents nameplate and differs from expected energy to be generated, which is expected to range from 200 MWa to 250 MWa, dependent upon river flows.

(2) Capacity represents nameplate and differs from expected energy to be generated, which is expected to range from 135 MWa to 180 MWa, dependent upon wind conditions.

For information regarding actual generating output and purchases for the years ended December 31, 2013, 2012 and 2011, 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 forced outages, availability and price of coal and natural gas, precipitation and snow-pack levels, the market price of electricity, and wind variability. As of December 31, 2013, the Company has new energy and capacity resources under construction, which are expected to be placed in service between 2015 and 2016. Such resources were selected pursuant to the competitive bidding process completed in 2013 in accordance with the Company's 2009 IRP. For additional information on these new energy and capacity resources see "*Capital Requirements*" in the Liquidity and Capital Resources section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Thermal On December 31, 2013, PGE acquired an additional 15% ownership interest in the Boardman coal-fired generating plant (Boardman), which it operates, increasing the Company's ownership share to 80% from 65%. For additional information, see Note 17, Jointly-owned Plant, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data." The Company also has a 20% ownership interest in 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 22% of the Company's total retail load requirement in 2013, compared with 19% in 2012 and 21% in 2011. The Company's three natural gas-fired generating facilities, Port Westward, Beaver, and Coyote Springs Unit 1 (Coyote Springs), provided approximately 18% of its total retail load requirement in 2013, compared with 15% in 2012 and 11% in 2011.

The thermal plants provide reliable power for the Company's customers and capacity reserves. These resources have a combined capacity of 1,919 MW, representing approximately 67% of the net capacity of PGE's generating facilities. Thermal plant availability, excluding Colstrip, was 84% in 2013, compared with 92% in 2012 and 90% in 2011, while Colstrip plant availability was 66% in 2013, compared with 93% in 2012 and 84% in 2011. Thermal plant availability percentages for 2013 were lower than 2012 and 2011 due to unplanned outages at three plants. For additional information on the unplanned plant outages, see "*Power Operations*" in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Hydro The Company's FERC-licensed hydroelectric projects consist of Pelton/Round Butte on the Deschutes River near Madras, Oregon (discussed below), four plants on the Clackamas River, and one on the Willamette River. The licenses for these projects expire at various dates ranging from 2035 to 2055. Although these plants have a combined capacity of 501 MW, actual energy received is dependent upon river flows. Energy from these resources provided 9% of the Company's total retail load requirement in 2013, compared with 10% in 2012 and in 2011, with availability of 100% in 2013, compared with 99% in 2012 and 100% in 2011. 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 465 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 or after December 31, 2021. The Tribes have a second option to purchase an undivided 0.02% interest in Pelton/Round Butte at its discretion on or after April 1, 2041. If both options are exercised by the Tribes, the Tribes' ownership percentage would exceed 50%.

Wind Biglow Canyon Wind Farm (Biglow Canyon), located in Sherman County, Oregon, is PGE's largest renewable energy resource with 217 wind turbines with a total nameplate capacity of approximately 450 MW. It was completed and placed in service in three phases between December 2007 and August 2010. The energy from Biglow Canyon provided 6% of the Company's total retail load requirement in 2013, 2012, and 2011. Availability for Biglow Canyon was 98% in 2013 and in 2012, and 97% in 2011. 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, dependent upon wind conditions.

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 support specific capacity needs. The program also helps provide NERC-required operating reserves. As of December 31, 2013, there were 49 projects with a total capacity of 93 MW. Additional DSG projects are being pursued with a goal of 100 MW online by the end of 2014.

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.

Coal *Boardman*—PGE has fixed-price purchase agreements that will provide coal for Boardman for the majority of 2014. The coal is obtained from surface mining operations in Wyoming and Montana and is delivered by rail under two separate transportation contracts which extend through 2020.

PGE expects to begin seeking requests for proposal in 2014 for the purchase of coal to fill remaining open positions for 2014, and to start layering open positions for 2015 and beyond. The terms of contracts and the quality of coal are expected to be staged in alignment with required emissions limits. PGE believes that sufficient market supplies of coal are available to meet anticipated operations of Boardman through 2020.

Natural Gas *Port Westward and Beaver*—PGE manages the price risk of natural gas supply for Port Westward through financial contracts up to 60 months in advance. Physical supplies for Port Westward and Beaver are generally purchased within 12 months of delivery and based on anticipated operation of the plants. PGE owns 79.5%, and is the operator of record, of the Kelso-Beaver Pipeline, which directly connects both generating plants to the Northwest Pipeline, an interstate natural gas pipeline operating between British Columbia and New Mexico. Currently, PGE transports 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 gas transportation capacity to serve the two plants.

PGE also has contractual access through April 2017 to natural gas storage in Mist, Oregon, from which it can draw in the event that gas supplies are interrupted or if economic factors require its use. This storage may be used to fuel both Port Westward and Beaver. PGE believes that sufficient market supplies of gas are available to meet anticipated operations of both plants for the foreseeable future.

Beaver has the capability to operate on No. 2 diesel fuel oil when it is economical or if the plant's natural gas supply is interrupted. PGE had an approximate 6-day supply of ultra-low sulfur diesel fuel oil at the plant site as of December 31, 2013. 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.

Coyote Springs—PGE manages the price risk of natural gas supply for Coyote Springs through financial contracts up to 60 months in advance, while physical supplies are generally purchased within 12 months of delivery and based on anticipated operation of the plant. Coyote Springs utilizes 41,000 Dth per day of natural gas when operating at full capacity, with firm transportation capacity on three pipeline systems accessing gas fields in Alberta, Canada. PGE believes that sufficient market supplies of gas are available for Coyote Springs for the foreseeable future, based on anticipated operation of the plant. Although Coyote Springs was designed to also operate on fuel oil, such capability has been deactivated in order to optimize natural gas operations.

Purchased Power

PGE supplements its own generation with power purchased in the wholesale market to meet its retail load requirements. The Company utilizes short- and long-term wholesale power purchase contracts in an effort to provide the most favorable economic mix on a variable cost basis. Such contracts have original terms ranging from one month to 53 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 two contracts that provide PGE with firm capacity to help meet the Company's peak loads. The contract representing 10 MW of capacity expires in May 2014 and the contract representing 150 MW of capacity expires in December 2016. In addition to PGE's capacity/exchange power purchase contracts presented in the preceding table, the Company entered into two power purchase agreements for up to 100 MW of seasonal peaking capacity pursuant to the competitive bidding process completed in 2013. One agreement covers winter from December 2014 to February 2019 and the second agreement covers summer from July 2014 to September 2018.

Hydro—The Company has four contracts that provide for the purchase of power generated from hydroelectric projects with an aggregate capacity of 117 MW and which expire between 2015 and 2018. In addition, PGE has the following:

- *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 three hydroelectric projects on the mid-Columbia River. The contract representing 163 MW of capacity expires in 2018 and the contract representing 168 MW of capacity expires in 2052. Although the projects currently provide a total of 331 MW of capacity, actual energy received is dependent upon river flows.

- *Confederated Tribes*—PGE has a long-term agreement under which the Company purchases, at market prices, the Tribes' interest in the output of the Pelton/Round Butte hydroelectric project. Although the agreement provides 155 MW of 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. The Tribes may elect to sell its output to another party with a one year notice to PGE.

Wind—PGE has three contracts that provide for the purchase of renewable wind-generated electricity and which extend to various dates between 2028 and 2035. Although these contracts provide a total of 39 MW of capacity, actual energy received is dependent upon wind conditions.

Solar—PGE has three agreements to purchase power generated from photovoltaic solar projects, which expire between 2036 and 2037. These projects have a combined generating capacity of 7 MW. In addition, the Company operates, and purchases power from four solar projects with an aggregate of approximately 6 MW of capacity.

Other—These primarily consist of long-term contracts to purchase power from various counterparties, including other Pacific Northwest utilities, over terms extending into 2031.

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 requirement.

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 30 minutes to less than one month. For additional information regarding PGE's power purchase contracts, see Note 15, Commitments and Guarantees, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Future Energy Resource Strategy

PGE is in the process of finalizing its next IRP (2013 IRP), which outlines the Company's expectations for resource needs and resource portfolio performance over the next 20 years. The 2013 IRP is expected to be filed with the OPUC by the end of March 2014. The 2013 IRP also includes an "Action Plan," which covers the Company's proposed actions over the next five years (2014 through 2018). Over this time period, PGE projects energy requirements to approximate, or slightly exceed, the energy available through its generation resources and long-term power purchase agreements. The Company believes that any shortfalls will be manageable through its wholesale purchasing strategy.

Based on PGE's current draft of the 2013 IRP, which was provided to the OPUC Staff in November 2013, the proposed Action Plan includes the following, among other components, between 2014 and 2017:

- Seek renewal, or partial renewal, of expiring power purchase agreements for energy generated from hydroelectric projects, if available and cost-effective for our customers;
- Acquisition of a total of 124 MWa of energy efficiency through continuation of Energy Trust of Oregon programs;
- To help manage peak load conditions and other supply contingencies, acquisition of 55 MW of demand response and PGE dispatchable standby generation from our customers;
- In preparation for the next IRP, perform various research and studies related to load forecast and energy efficiency projections, distributed PV solar application within PGE's service territory, the viability of large-scale biomass operations, fuel supply, wind integration needs, and operational flexibility requirements; and
- Retain and acquire transmission service through Bonneville Power Administration's (BPA's) OATT to interconnect new and existing resources in eastern Oregon to PGE's service territory.

The draft 2013 IRP also incorporates the selected energy and capacity resources resulting from the outcome of the competitive bidding process in 2013 pursuant to the Company's 2009 IRP, the most recent IRP acknowledged by the OPUC. These new resources are currently under construction and are expected to be in service between 2015 and 2016. For additional information on these capital projects see "*Capital Requirements*" in the Liquidity and Capital Resources section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Beyond 2018, PGE projects it will need to procure new resources in order to meet the 2020 and 2025 RPS requirements and to replace energy from Boardman, which is scheduled to cease coal-fired operations in 2020. Additional post-2018 actions may also be needed to offset expiring power purchase agreements and to back-up variable energy resources, such as wind generation facilities. These actions are expected to be identified in a future IRP.

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 2013, PGE delivered approximately 22 million megawatt hours (MWh) in its balancing authority area through 1,141 circuit miles of transmission lines operating at or above 115 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 BPA to transmit a significant amount of the Company's generation to 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 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 state lands under franchises, easements or other rights that are generally subject to termination;
- Under or over private property as a result of easements obtained primarily from the record holder of title; or
- 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 in accordance with FERC Standards of Conduct. 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.

PGE continues to meet state regulatory requirements related to power distribution service quality and reliability. Such requirements are reflected in specific indices that measure outage duration, outage frequency, and momentary power interruptions. The Company is required to include performance results related to service quality measures in annual reports filed with the OPUC. Specific monetary penalties can be assessed for failure to attain required performance levels, with amounts dependent upon the extent to which actual results fail to meet such requirements.

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

Environmental Matters

PGE's operations are subject to a wide range of environmental protection laws and regulations, which pertain to air and water quality, endangered species and wildlife protection, and hazardous material. Various state and federal agencies regulate environmental matters that relate to the siting, construction, and operation of generation, transmission, and substation facilities and the handling, accumulation, cleanup, 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.

The United States Environmental Protection Agency (EPA) has issued emissions limits under the CAA National Emission Standards for Hazardous Air Pollutants (NESHAP) to regulate hazardous air emissions from coal and oil fired electric generating units. Emissions limits included in the NESHAP are based on the application of maximum achievable control technology (MACT). Installation of emissions controls to meet the emissions limits for sulfur dioxide (SO_2) and nitrous oxide at Boardman, which include a Dry Sorbent Injection system, was completed in 2013. With the addition of these controls, the Company believes the Boardman plant should meet the MACT requirements without additional capital investment. Oregon Department of Environmental Quality (DEQ) rules provide for coal-fired operation at Boardman to cease no later than December 31, 2020.

Emissions controls in place at Colstrip allow operation within the standards necessary to meet the MACT requirements. The Company does not anticipate further capital investment to meet the requirements currently in place.

Although regulation of mercury emissions is contemplated under NESHAP, the states of Oregon and Montana have previously adopted regulations concerning mercury emissions. Both Boardman and Colstrip meet the mercury compliance requirements in their respective states.

PGE manages its air emissions by the use of low sulfur fuel, emissions and combustion controls and monitoring, and SO_2 allowances awarded under the CAA. The current allowance inventory and expected future annual SO_2 allowances, along with the recent and planned installation of emissions controls, are anticipated to be sufficient to permit the Company to continue to meet its compliance requirements and operate its thermal generating plants at forecasted capacity for at least the next several years.

Climate Change—No comprehensive GHG emissions legislation has been considered and voted on by Congress in recent years. However, state, regional, and federal legislative efforts continue with respect to establishing regulation of GHG emissions and their potential impacts on climate change. Currently, the EPA has taken the lead role on climate change policy utilizing existing authority under the CAA to develop regulations. Areas of focus for the Company include the following:

- In December 2010, the EPA announced a proposed settlement agreement with states and environmental groups that would require the EPA to set GHG New Source Performance Standards (NSPS) for new and modified fossil fuel-based power plants, and guidelines for state-developed NSPS for existing sources. The emissions standards for new natural gas- and coal-fired electric generating units were proposed in April 2012 under the CAA, but have yet to be finalized, as the EPA is in the process of issuing a revised proposal. The EPA has also been directed to propose emissions standards under the CAA for existing fossil fuel-based power plants by June 2014 and issue a final rule one year later. It is expected that individual states will have flexibility that would allow for an array of tools, including RPS and cap and trade programs, to be used to comply with new standards. The Company continues to monitor the developments around the federal proposals.

- The State of Oregon established a non-binding policy guideline that sets a goal to reduce GHG emissions to 10% below 1990 levels by 2020 and at least 75% below 1990 levels by 2050. Although the guideline does not mandate reductions by any specific entity nor include penalties for failure to meet the goal, the Company is required to report to the DEQ the amount of GHG emissions produced along with the total amount of energy produced or purchased by PGE for consumption in Oregon.

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. PGE's natural gas-fired facilities, Beaver, Coyote Springs, and Port Westward, and the Company's ownership interest in coal-fired facilities, Boardman and Colstrip, provided approximately 67% of the Company's net generating capacity during 2013. If PGE were to incur incremental costs as a result of changes in the regulations regarding GHGs, the Company would seek recovery in customer prices.

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.

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 have caused major operational changes to many of the region's hydroelectric projects. PGE purchases power in the wholesale market to serve its retail load requirements and has contracts to purchase power generated at some of the affected facilities on the mid-Columbia River in central Washington.

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 and the National Marine Fisheries Service under their authority granted in the ESA and the Federal Power Act. 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 50 MWa of their output included as part of the Company's renewable energy portfolio used to meet the requirements of the Oregon RPS. Conditions required with the operating licenses are expected to result in a minor reduction in power production and increase capital spending to modify the facilities to enhance fish passage and survival.

Avian Protection—Various statutory authorities as well as the Migratory Bird Treaty Act have established civil, criminal, and administrative penalties for the unauthorized take of migratory birds. Because PGE operates electric transmission lines and wind generation facilities that can pose risks to a variety of such birds, the Company is required to have an avian protection plan to reduce risks to bird species that can result from Company operations. PGE has developed and implemented such a plan for its transmission and distribution facilities and continues to develop similar plans for its wind generation facilities. In 2014, the avian protection plan is expected to be finalized for Biglow Canyon, while data collection will occur at Tucannon River with a plan expected in 2015.

Hazardous Waste

PGE has a comprehensive program to comply with requirements of both federal and state regulations related to hazardous waste storage, handling, and disposal. The handling and disposal of hazardous waste 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.

Boardman and Colstrip produce coal combustion byproducts (CCBs), which have historically not been considered hazardous waste under the RCRA. The EPA continues to consider listing these residuals as hazardous waste, which would likely have an impact on current disposal practices and could increase the Company's cost of handling these materials. The EPA is expected to issue a proposed rulemaking by the end of 2014. The Company cannot predict the possible impact of this matter until the EPA provides further guidance on the proposed rules. If PGE were to incur incremental costs as a result of changes in the regulations, the Company would seek recovery in customer prices.

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

A 1997 investigation by the EPA of a segment of the Willamette River known as Portland Harbor revealed significant contamination of river sediments and prompted the EPA to subsequently include Portland Harbor on the federal National Priority List as a Superfund site pursuant to CERCLA. The EPA initially listed sixty-nine Potentially Responsible Parties (PRPs), including PGE as it has historically owned or operated property near the river. In 2008, the EPA requested further information from various parties, including PGE, concerning property several miles beyond the original river segment and, as a result, the PRPs now number over one hundred. In March 2012, a draft feasibility study was submitted to the EPA for review and approval. A Record of Decision is expected from the EPA in 2015 on the various clean-up alternatives, which, as outlined in the draft feasibility study, could take up to 28 years to complete and range in cost from $169 million to $1.8 billion. It is unclear for what portion, if any, that PGE might be held responsible.

For additional information on this EPA action, 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, which is not likely to be before 2020. Shipment of the spent nuclear fuel from the ISFSI to off-site storage is not expected to be completed prior to 2033. For additional information regarding this matter, see "*Trojan decommissioning activities*" in Note 7, Asset Retirement Obligations, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

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.

In February 2014, PGE filed with the OPUC a 2015 General Rate Case with a 2015 test year. For additional information regarding the 2015 General Rate Case, see the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations." In PGE's three most recent general rate cases (2014, 2011 and 2009), overall price increases approved by the OPUC were less than the Company's initial proposals. Under such circumstances, PGE attempts to manage its costs at levels consistent with the reduced price increases. 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 which 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. PGE files an annual AUT with an update of the Company's forecasted net variable power costs (baseline NVPC) to be reflected in customer prices. The PCAM provides a mechanism by which the Company can adjust future customer prices to reflect a portion of the difference between each year's baseline NVPC included in customer prices and actual NVPC. PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and baseline NVPC by application of an asymmetrical "deadband." The PCAM provides for a fixed deadband range of $15 million below, to $30 million above, baseline NVPC. 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 winters or cooler-than-normal summers 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. In 2013, the Company experienced forced outages at three of its generating plants, and as a result, incurred incremental replacement power costs of $17 million. 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's current position as a "short" utility requires that the Company supplement 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 the interest rates and 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 Standard & Poor's Ratings Services (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 those related to PGE's recovery of its investment in Trojan, the proceedings related to refunds on wholesale market transactions in the Pacific Northwest and the investigation and any resulting remediation efforts related to the Portland Harbor site, that 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 low-cost hydroelectric generating resources would require increased energy from the Company's higher cost thermal generating plants 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 scheduled.

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. For additional information concerning PGE's capital requirements, see "*Capital Requirements*" in the Liquidity and Capital Resources section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

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 greenhouse gas 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 greenhouse gas emissions from the Company's fossil fuel-fired generation facilities. Compliance with any greenhouse gas 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 greenhouse gas emissions reduction requirements is subject to significant uncertainties, including those related to: the timing of the implementation of emissions reduction rules; required levels of emissions reductions; requirements with respect to the allocation of emissions allowances; the maturation, regulation and commercialization of carbon capture and sequestration technology; and 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.

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 unsecured revolving credit facilities with several banks for an aggregate amount of $700 million. These revolving credit facilities provide a primary source of liquidity and may be used to supplement operating cash flow and as backup for commercial paper borrowings.

The revolving credit facilities represent commitments by the participating banks to make loans and, in certain cases, to issue letters of credit. The Company is required to make certain representations to the banks each time it requests an advance under one of the credit facilities. 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 facilities.

In addition, it is possible that the Company might not be aware of certain developments at the time it makes such a representation in connection with a request for a loan, which could cause the representation to be untrue at the time made and constitute an event of default. Such a circumstance could result in a loss of the banks' commitments under the credit facilities and, in certain circumstances, the accelerated repayment of any outstanding loan balances.

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.

For additional information regarding PGE's contribution obligations under its pension and non-qualified benefit plans, see "*Contractual Obligations and Commercial Commitments*" in the Liquidity and Capital Resources section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations," and "*Pension and Other Postretirement Plans*" in Note 10, Employee Benefits, in the Notes to Consolidated Financial Statements in Item 8.— "Financial Statements and Supplementary Data."

Changes in technology may negatively impact the revenues derived from 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, such as fuel cells, photovoltaic (solar) cells, micro-turbines and other forms of distributed generation. It is possible that advances in such technologies will reduce the cost of alternative methods of electricity production to a level that is equal to or below that of central thermal and wind generation facilities. Such a development could limit the Company's future growth opportunities and limit growth in demand for PGE's electric service.

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

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

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

A portion of PGE's total energy requirement is supplied with power generated from hydroelectric and wind generating resources. Operation of these facilities is subject to regulation related to the protection of fish and wildlife. The listing of various plants and species of fish, birds, and other wildlife as threatened or endangered has resulted in significant operational changes to these projects. Salmon recovery plans could include further major operational changes to the region's hydroelectric projects, including those owned by PGE and those from which the Company purchases power under long-term contracts. In addition, laws relating to the protection of migratory birds and other wildlife could impact the development and operation of transmission 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 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 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 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.

The OPUC has authorized the Company to collect $2 million annually from retail customers for such damages and to defer any amount not utilized in the current year. The deferred amount, $6 million as of December 31, 2013, along with the annual collection, would be available to offset potential storm damage costs in future years.

PGE utilizes insurance, when possible, to mitigate the cost of physical loss or damage to the Company's property. As cost effective insurance coverage for transmission and distribution line property (poles and wires) is currently not available, however, the Company would likely seek recovery of large losses to such property through the ratemaking process.

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

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

PGE has a workforce with a significant number of employees approaching retirement, which could make it more difficult to maintain the workforce necessary to provide safe and reliable service to customers and meet regulatory requirements.

The Company anticipates higher averages of retirement rates over the next several years and will likely need to replace a significant number of employees in key positions. PGE's ability to successfully implement a workforce succession plan is dependent upon the Company's ability to employ and retain skilled professional and technical workers. Without a skilled workforce, the Company would face greater challenges in providing safe and reliable service to its customers and meeting regulatory requirements, both of which could affect operating results.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

PGE's principal property, plant, and equipment are 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. PGE leases its corporate headquarters complex, located in Portland, Oregon. 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, 2013:

Facility	Location	Net Capacity [1]	
Wholly-owned:			
Hydro:			
Faraday	Clackamas River	46	MW
North Fork	Clackamas River	58	
Oak Grove	Clackamas River	44	
River Mill	Clackamas River	25	
T.W. Sullivan	Willamette River	18	
Natural Gas/Oil:			
Beaver	Clatskanie, Oregon	516	
Port Westward	Clatskanie, Oregon	402	
Coyote Springs	Boardman, Oregon	245	
Wind:			
Biglow Canyon	Sherman County, Oregon	450	
Jointly-owned [2]:			
Coal:			
Boardman [3]	Boardman, Oregon	460	
Colstrip [4]	Colstrip, Montana	296	
Hydro:			
Pelton [5]	Deschutes River	73	
Round Butte [5]	Deschutes River	237	
Total net capacity		2,870	MW

(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) Reflects PGE's ownership share.

(3) PGE operates Boardman and has an 80% ownership interest, which, on December 31, 2013, increased from 65%. For additional information concerning the Company's acquisition of an additional 15% ownership interest in Boardman, see Note 17, Jointly-owned Plant, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

(4) PPL Montana, LLC operates Colstrip and PGE has a 20% ownership interest.

(5) PGE operates Pelton and Round Butte and has a 66.67% ownership interest.

PGE's hydroelectric projects are operated pursuant to FERC licenses issued under the Federal Power Act. 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 and/or has contractual rights associated with transmission lines that deliver electricity from its Oregon generation facilities to its distribution system in its service territory and also to the Western Interconnection. As of December 31, 2013, PGE owned an electric transmission system consisting of 1,141 circuit miles as follows: 212 circuit miles of 500 kV line; 382 circuit miles of 230 kV line; and 547 miles of 115 kV line. The Company also has 26,867 circuit miles of primary and secondary distribution lines that deliver electricity to its customers.

The Company also has an ownership interest in the following transmission facilities:

- Approximately 14% of the capacity on the Montana Intertie from the Colstrip plant in Montana to BPA's transmission system; and
- Approximately 20% of the capacity on the Pacific Northwest Intertie, a 4,800 MW transmission facility between John Day, in northern Oregon, and Malin, in southern 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 3,100 MW of firm BPA transmission on BPA's system to PGE's service territory in Oregon; and
- 200 MW of firm BPA transmission from mid-Columbia projects in Washington to the northern end of the Pacific Northwest Intertie, near John Day, Oregon, and 100 MW to the northern end of the Pacific DC Intertie, near Celilo, Oregon.

ITEM 3. LEGAL PROCEEDINGS.

Citizens' Utility Board of Oregon v. Public Utility Commission of Oregon and Utility Reform Project and Colleen O'Neill v. Public Utility Commission of Oregon, Public Utility Commission of Oregon, Marion County Oregon Circuit Court, the Court of Appeals of the State of Oregon, and the Oregon Supreme Court.

PGE, in its 1993 general rate filing, sought OPUC approval to recover through rates future decommissioning costs and full recovery of, and a rate of return on, its Trojan investment. PGE's request was challenged, but in August 1993, the OPUC issued a Declaratory Ruling in PGE's favor. The Citizens' Utility Board (CUB) appealed the decision to the Oregon Court of Appeals.

In PGE's 1995 general rate case, the OPUC issued an order (1995 Order) granting PGE full recovery of Trojan decommissioning costs and 87% of its remaining undepreciated investment in the plant. The Utility Reform Project (URP) filed an appeal of the 1995 Order to the Marion County Circuit Court. The CUB also filed an appeal to the Marion County Circuit Court challenging the portion of the 1995 Order that authorized PGE to recover a return on its remaining undepreciated investment in Trojan.

In April 1996, the Marion County Circuit Court issued a decision that found that the OPUC could not authorize PGE to collect a return on its undepreciated investment in Trojan. The 1996 decision was appealed to the Oregon Court of Appeals.

In June 1998, the Oregon Court of Appeals ruled that the OPUC did not have the authority to allow PGE to recover a rate of return on its undepreciated investment in Trojan. The court remanded the matter to the OPUC for reconsideration of its 1995 Order in light of the court's decision.

In September 2000, PGE, CUB, and the OPUC Staff settled proceedings related to PGE's recovery of its investment in the Trojan plant (Settlement). The URP did not participate in the Settlement and filed a complaint with the OPUC, challenging PGE's application for approval of the accounting and ratemaking elements of the Settlement.

In March 2002, the OPUC issued an order (Settlement Order) denying all of the URP's challenges and approving PGE's application for the accounting and ratemaking elements of the Settlement. The URP appealed the Settlement Order to the Marion County Circuit Court. Following various appeals and proceedings, the Oregon Court of Appeals issued an opinion in October 2007 that reversed the Settlement Order and remanded the Settlement Order to the OPUC for reconsideration.

As a result of its reconsideration of the Settlement Order, the OPUC issued an order in September 2008 that required PGE to refund $33.1 million to customers. The Company completed the distribution of the refund to customers, plus accrued interest, as required.

In October 2008, the URP and the Class Action Plaintiffs (described in the Dreyer proceeding below) separately appealed the September 2008 OPUC order to the Oregon Court of Appeals. On February 6, 2013, the Oregon Court of Appeals issued an opinion that upheld the September 2008 OPUC order.

On October 18, 2013, the Oregon Supreme Court accepted plaintiffs' petition seeking review of the February 6, 2013 Oregon Court of Appeals decision. Opening briefs have been filed with oral argument scheduled for March 4, 2014.

Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company, Marion County Circuit Court; and Morgan v. Portland General Electric Company, Marion County Circuit Court.

In January 2003, two class action suits were filed in Marion County Circuit Court against PGE. The Dreyer case seeks to represent current PGE customers that were customers during the period from April 1, 1995 to October 1, 2000 (Current Class) and the Morgan case seeks to represent PGE customers that were customers during the period from April 1, 1995 to October 1, 2000, but who are no longer customers (Former Class, together with the Current Class, the Class Action Plaintiffs). The suits seek damages of $190 million plus interest for the Current Class and $70 million plus interest for the Former Class, from the inclusion of a return on investment of Trojan in the rates PGE charged its customers.

In April 2004, the Class Action Plaintiffs filed a Motion for Partial Summary Judgment and in July 2004, PGE also moved for Summary Judgment in its favor on all of the Class Action Plaintiffs' claims. In December 2004, the Judge granted the Class Action Plaintiffs' motion for Class Certification and Partial Summary Judgment and denied PGE's motion for Summary Judgment. In March 2005, PGE filed two Petitions with the Oregon Supreme Court asking the Court to take jurisdiction and command the trial Judge to dismiss the complaints, or to show cause why they should not be dismissed, and seeking to overturn the Class Certification.

In August 2006, the Oregon Supreme Court issued a ruling on PGE's Petitions abating these class action proceedings until the OPUC responded with respect to the certain issues that had been remanded to the OPUC by the Marion County Circuit Court in the proceeding described above.

In October 2006, the Marion County Circuit Court issued an Order of Abatement in response to the ruling of the Oregon Supreme Court, abating the class actions for one year.

In October 2007, the Class Action Plaintiffs filed a Motion with the Marion County Circuit Court to lift the abatement. In February 2009, the Circuit Court judge denied the Motion to lift the abatement.

<u>Puget Sound Energy, Inc. v. All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western System Power Pool Agreement</u>, Federal Energy Regulatory Commission and Ninth Circuit Court of Appeals (collectively, Pacific Northwest Refund proceeding).

In July 2001, the FERC called for a preliminary evidentiary hearing to explore whether there may have been unjust and unreasonable charges for spot market sales of electricity in the Pacific Northwest from December 25, 2000 through June 20, 2001. During that period, PGE both sold and purchased electricity in the Pacific Northwest. In June 2003, the FERC issued an order terminating the proceeding and denying the claims for refunds. Parties appealed various aspects of these FERC orders to the U.S. Ninth Circuit Court of Appeals (Ninth Circuit).

In August 2007, the Ninth Circuit issued its decision on appeal, concluding that the FERC failed to adequately explain how it considered or examined new evidence showing intentional market manipulation in California and the potential ties to the Pacific Northwest and that the FERC should not have excluded from the Pacific Northwest Refund proceeding purchases of energy made by the California Energy Resources Scheduling (CERS) division in the Pacific Northwest spot market. The Ninth Circuit remanded the case to the FERC to (i) address the new market manipulation evidence in detail and account for the evidence in any future orders regarding the award or denial of refunds in the proceedings, (ii) include sales to CERS in its analysis, and (iii) further consider its refund decision in light of related, intervening opinions of the court. The Ninth Circuit offered no opinion on the FERC's findings based on the record established by the administrative law judge and did not rule on the FERC's ultimate decision to deny refunds. After denying requests for rehearing, the Ninth Circuit, in April 2009, issued a mandate giving immediate effect to its August 2007 order remanding the case to the FERC.

In October 2011, the FERC issued an Order on Remand establishing an evidentiary hearing to determine whether any seller had engaged in unlawful market activity in the Pacific Northwest spot markets during the December 25, 2000 through June 20, 2001 period by violating specific contracts or tariffs, and, if so, whether a direct connection existed between the alleged unlawful conduct and the rate charged under the applicable contract. The FERC held that the *Mobile-Sierra* public interest standard governs challenges to the bilateral contracts at issue in this proceeding, and the strong presumption under *Mobile-Sierra* that the rates charged under each contract are just and reasonable would have to be specifically overcome before a refund could be ordered. The FERC directed the presiding judge, if necessary, to determine a refund methodology and to calculate refunds, but held that a market-wide remedy was not appropriate, given the bilateral contract nature of the Pacific Northwest spot markets. Certain parties claiming refunds filed requests for rehearing of the Order on Remand.

In December 2012, the FERC issued an order granting an interlocutory appeal of the trial judge's ruling on the scope of the remand proceeding. In this order, the FERC held that its Order on Remand was not intended to alter the general state of the law regarding the *Mobile-Sierra* presumption. The FERC also held that the *Mobile-Sierra* presumption could be overcome either by (i) a showing that a respondent had violated a contract or tariff and that the violation had a direct connection to the rate charged under the applicable contract or (ii) a showing that the contract rate at issue imposed an excessive burden or seriously harmed the public interest.

On April 5, 2013, and subject to its December 2012 clarification in the interlocutory appeal, the FERC denied rehearing requests from refund proponents that had contested the FERC's use of the *Mobile-Sierra* standard in the remand proceeding, its denial of a market-wide remedy, and the restraints in the Order on Remand that limited the types of evidence that could be introduced in the hearing. However, the FERC granted rehearing on the issue of the appropriate refund period, holding that parties could pursue refunds for transactions between January 1, 2000 and December 24, 2000 under Section 309 of the Federal Power Act by showing violations of a filed tariff or rate schedule or of a statutory requirement. Refund claimants have filed petitions for appeal of the Order on Remand and the Order on Rehearing with the Ninth Circuit.

In its October 2011 Order on Remand, the FERC held the hearing procedures in abeyance pending the results of settlement discussions, which it ordered be convened before a FERC settlement judge. Pursuant to the settlement proceedings, the Company received notice of two claims and reached agreements to settle both claims for an immaterial amount. The FERC approved both settlements during 2012.

In May 2007, the FERC approved a settlement between PGE and certain parties in the California refund case in Docket No. EL00-95, et seq. This resolved the claims between PGE and the California parties named in the settlement as to transactions in the Pacific Northwest during the settlement period, January 1, 2000 through June 20, 2001. The settlement with the California parties did not resolve potential claims from other market participants relating to transactions in the Pacific Northwest.

The above-referenced settlements resulted in a release of the Company as a named respondent in the ongoing remand proceedings, which are limited to initial and direct claims for refunds, but there remains a possibility that additional claims could be asserted against the Company in future proceedings if refunds are ordered against current respondents.

Sierra Club and Montana Environmental Information Center v. PPL Montana LLC, Avista Corporation, Puget Sound Energy, Portland General Electric Company, Northwestern Corporation, and PacifiCorp, U.S. District Court for the District of Montana.

On July 30, 2012, PGE received a Notice of Intent to Sue (Notice) for violations of the CAA at Colstrip Steam Electric Station (CSES) from counsel on behalf of the Sierra Club and the Montana Environmental Information Center (MEIC). The Notice was also addressed to the other CSES co-owners, including PPL Montana, LLC - the operator of CSES. PGE has a 20% ownership interest in Units 3 and 4 of CSES. The Notice alleges certain violations of the CAA, and stated that the Sierra Club and MEIC would: i) request a United States District Court to impose injunctive relief and civil penalties; ii) require a beneficial environmental project in the areas affected by the alleged air pollution; and iii) seek reimbursement of Sierra Club's and MEIC's costs of litigation and attorney's fees.

The Sierra Club and MEIC asserted that the CSES owners violated the Title V air quality operating permit during portions of 2008 and 2009 and that the owners have violated the CAA by failing to timely submit a complete air quality operating permit application to the Montana Department of Environmental Quality. The Sierra Club and MEIC also asserted violations of opacity provisions of the CAA.

On March 6, 2013, the Sierra Club and MEIC sued the CSES co-owners, including PGE, for these and additional alleged violations of various environmental related regulations. The plaintiffs are seeking relief that includes civil penalties and an injunction preventing the co-owners from operating CSES except in accordance with the CAA, the Montana State Implementation Plan, and the plant's federally enforceable air quality permits. In addition, plaintiffs are seeking civil penalties against the co-owners including $32,500 per day for each violation occurring through January 12, 2009, and $37,500 per day for each violation occurring thereafter. On May 3, 2013, the defendants filed a motion to dismiss 36 of the 39 claims in the suit. On September 27, 2013, the plaintiffs filed an amended complaint that deleted the Title V and opacity claims, added claims associated with two 2011 projects, and expanded the scope of certain claims to encompass approximately 40 additional projects. This matter is scheduled for trial in March 2015.

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". As of February 10, 2014, there were 964 holders of record of PGE's common stock and the closing sales price of PGE's common stock on that date was $29.40 per share. The following table sets forth, for the periods indicated, the highest and lowest sales prices of PGE's common stock as reported on the NYSE.

	High	Low	Dividends Declared Per Share
2013			
Fourth Quarter	$ 30.57	$ 27.82	$ 0.275
Third Quarter	33.26	27.57	0.275
Second Quarter	32.91	29.14	0.275
First Quarter	30.53	27.42	0.270
2012			
Fourth Quarter	$ 28.08	$ 24.86	$ 0.270
Third Quarter	27.92	26.57	0.270
Second Quarter	26.94	24.25	0.270
First Quarter	25.62	24.29	0.265

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

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,				
	2013	2012	2011	2010	2009
	(In millions, except per share amounts)				
Statement of Income Data:					
Revenues, net	$ 1,810	$ 1,805	$ 1,813	$ 1,783	$ 1,804
Gross margin	58%	60%	58%	54%	48%
Income from operations [(1)]	$ 206	$ 302	$ 309	$ 267	$ 208
Net income [(1)]	104	140	147	121	89
Net income attributable to Portland General Electric Company [(1)]	105	141	147	125	95
Earnings per share—basic [(1)]	1.36	1.87	1.95	1.66	1.31
Earnings per share—diluted [(1)]	1.35	1.87	1.95	1.66	1.31
Dividends declared per common share	1.095	1.075	1.055	1.035	1.010
Statement of Cash Flows Data:					
Capital expenditures	656	303	300	450	696

(1) The year ended December 31, 2013 includes $52 million of costs expensed related to the Company's Cascade Crossing Transmission Project.

	As of December 31,				
	2013	2012	2011	2010	2009
	(Dollars in millions)				
Balance Sheet Data:					
Total assets	$ 6,101	$ 5,670	$ 5,733	$ 5,491	$ 5,172
Total long-term debt	1,916	1,636	1,735	1,808	1,744
Total Portland General Electric Company shareholders' equity	1,819	1,728	1,663	1,592	1,542
Common equity ratio	48.7%	51.1%	48.6%	46.7%	46.9%

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 and results of operations, business prospects, future loads, the outcome of litigation and regulatory proceedings, future capital expenditures, market conditions, future events or performance and other matters. Words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "plans," "predicts," "projects," "will likely result," "will continue," "should," or similar expressions are intended to identify such forward-looking statements.

Forward-looking statements are not guarantees of future performance and involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed. PGE's expectations, beliefs and projections are expressed in good faith and are believed by PGE to have a reasonable basis including, but not limited to, management's examination of historical operating trends and data contained in records and other data 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 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, which may cause the Company to incur repair costs, as well as increased power costs for replacement power;
- the failure to complete capital projects on schedule and within budget or the abandonment of capital projects, 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 existing power and natural gas purchase agreements;
- capital market conditions, including access to capital, interest rate volatility, reductions in demand for investment-grade commercial paper, as well as changes in PGE's credit ratings, 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 or affect the operations of the Company's thermal generating 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 wholesale prices for fuels, including natural gas, coal and oil, and the impact of such changes on the Company's power costs;
- changes in the availability and price of wholesale power;
- 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;
- changes in, and compliance with, environmental and endangered species laws and policies;
- 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;
- new federal, state, and local laws that could have adverse effects on operating results;
- 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 and proprietary information;
- employee workforce factors, including a significant number of employees approaching retirement, potential strikes, work stoppages, and transitions in senior management;
- political, economic, and financial market conditions;
- natural disasters and other risks, such as earthquake, flood, drought, lightning, wind, and fire;
- 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, nor can it 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

Operating Activities—PGE is a vertically integrated electric utility engaged in the generation, transmission, distribution, and retail sale of electricity in the state of Oregon, as well as the wholesale purchase and sale of electricity and natural gas in the United States and Canada. The Company generates revenues and cash flows primarily from the retail sale and distribution of electricity to customers in its service territory.

The Company's revenues and income from operations can fluctuate during the year due to, among other variables, the impacts of seasonal weather conditions on the demand for electricity and changes in retail prices for electricity and in customer usage patterns. In addition, the availability and price of power and fuel can affect income from operations. PGE is a winter-peaking utility that typically experiences its highest retail energy demand during the winter heating season, with a slightly lower peak in the summer that generally results from air conditioning demand.

Customers and Demand—Residential energy deliveries increased 2.6% in 2013 from 2012, reflecting the effects of weather. During 2013, heating and cooling degree-days (indicator of the effect of weather on demand for energy) combined were 7% higher than 2012, when more normal seasonal weather conditions prevailed. Energy deliveries to commercial and industrial customers combined for 2013 were comparable to 2012. Energy efficiency and conservation efforts by retail customers influence demand, although the financial effects of such efforts are intended to be mitigated by the decoupling mechanism.

The following table indicates the average number of retail customers and deliveries, by customer class, during the past two years:

	2013		2012		Increase/ (Decrease) in Energy Deliveries
	Average Number of Customers	Energy Deliveries *	Average Number of Customers	Energy Deliveries *	
Residential	728,481	7,702	723,440	7,505	2.6%
Commercial	104,385	7,441	103,766	7,402	0.5
Industrial	263	4,276	261	4,283	(0.2)
Total	833,129	19,419	827,467	19,190	1.2%

* In thousands of MWh.

Adjusted for the effects of weather, total retail energy deliveries in 2013 were comparable to 2012. PGE projects that retail energy deliveries for 2014 will increase approximately 1% from 2013 weather adjusted levels, after allowing for energy efficiency and conservation efforts.

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 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. More extensive planned service maintenance was performed in 2011, compared to 2013 and 2012.

In addition, unplanned plant outages impact the plants' availability and during the second half of 2013, three different plants had unplanned outages ranging from four weeks to six months as follows:

- Colstrip Unit 4 tripped off-line on July 1, 2013 as a result of damage that occurred in the unit's generator. PPL Montana, LLC is the operator of Colstrip Unit 4, of which PGE has a 20% ownership interest representing 148 MW net capacity. Total repair costs are estimated at $30 million, with PGE's share representing $6 million. The majority of the repair costs are expected to be capitalized. The plant came back online in late January 2014.

- Boardman was off-line July 1, 2013 to July 31, 2013 as a result of a thermal water hammer event causing structural damage to the cold reheat piping line that runs between the turbine and the boiler. PGE is the operator of Boardman and had a 65% ownership interest representing 374 MW net capacity at the time of the outage. Total repair costs amounted to $10 million, the majority of which have been capitalized net of $6.7 million of insurance proceeds.

- Coyote Springs was off-line from August 24, 2013 to November 30, 2013 as a result of cracks in the steam turbine rotor. Coyote Springs has a net capacity of 246 MW, which represents approximately 9% of the Company's total net generating capacity. Total repair costs amounted to $2 million, which is included in operating and maintenance expense.

As a result of these unplanned outages, the Company incurred $17 million of incremental power costs to replace its share of the output of these plants over the period of time the plants were off-line in 2013. These incremental replacement power costs are included in actual NVPC in the Company's PCAM calculation for 2013.

Availability of the plants PGE operates approximated 89%, 94%, and 93% for the years ended December 31, 2013, 2012, and 2011, respectively, with the availability of Colstrip, which PGE does not operate, approximating 66%, 93%, and 84%, respectively.

During the year ended December 31, 2013, the Company's generating plants provided approximately 54% of its retail load requirement, compared to 50% in 2012 and 48% in 2011. The lower relative volume of power generated to meet the Company's retail load requirement during 2012 and 2011 was primarily due to the economic displacement of thermal generation by energy received from hydro resources and lower-cost purchased power.

Energy received from PGE-owned hydroelectric plants and under contracts from mid-Columbia hydroelectric projects decreased 11% in 2013 compared to 2012, primarily due to less favorable hydro conditions in 2013. These resources provided approximately 17% of the Company's retail load requirement for 2013, compared with 19% for 2012 and 25% for 2011. Energy received from these sources exceeded projections (or "normal") included in the Company's AUT by approximately 1% in 2013, 11% in 2012, and 13% in 2011. 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" represents the level of energy forecasted to be received from hydroelectric resources for the year and is based on average regional hydro conditions. Any excess in hydro 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. Based on recent forecasts of regional hydro conditions, energy from hydro resources is expected to be below normal for 2014.

Energy expected to be received from wind generating resources is projected annually in the AUT and through 2013, was based on wind studies completed in connection with the permitting process of the wind farm. For 2014 and beyond, the projection included in the AUT will be 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 will be based on the wind studies. 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 15% in 2013, 20% in 2012 and 13% in 2011.

Pursuant to the Company's PCAM, customer prices can be adjusted to reflect a portion of the difference between each year's forecasted NVPC included in prices (baseline NVPC) and actual NVPC for the year, to the extent such difference is outside of a pre-determined "deadband," which ranges from $15 million below to $30 million above baseline NVPC. To the extent actual NVPC is above or below the deadband, the PCAM provides for 90% of the variance to be collected from or refunded to customers, respectively, subject to a regulated earnings test. The following is a summary of the impacts of the PCAM for 2013, 2012 and 2011.

- For 2013, actual NVPC was above baseline NVPC by $11 million, which is within the established deadband range. Accordingly, no customer refund or collection was recorded as of December 31, 2013. A final determination regarding the 2013 PCAM results will be made by the OPUC through a public filing and review in 2014.

- For 2012, actual NVPC was below baseline NVPC by $17 million, and exceeded the lower deadband threshold of $15 million. However, based on results of the regulated earnings test, no estimated refund to customers was recorded as of December 31, 2012. A final determination regarding the 2012 PCAM results was made by the OPUC through a public filing and review in 2013, which confirmed no refund to customers pursuant to the PCAM for 2012.

- For 2011, actual NVPC was below baseline NVPC by $34 million, and exceeded the lower deadband threshold of $15 million. PGE recorded an estimated refund to customers of $10 million as of December 31, 2011, reduced from the $17 million potential refund to customers as a result of the regulated earnings test. A final determination regarding the 2011 PCAM results was made by the OPUC through a public filing and review in 2012, which, based upon the application of an updated regulated earnings test, resulted in a revised refund to customers of $6 million, which was returned to customers over a one-year period that began January 1, 2013.

For further information concerning the PCAM see *Power Costs* under "*State of Oregon Regulation*" in the Regulation section of Item 1.—"Business."

General Rate Cases—On December 9, 2013, the OPUC issued an order on PGE's 2014 General Rate Case, which was based on a 2014 test year. The OPUC authorized a $61 million increase in annual revenues, representing an approximate 4% overall increase in customer prices. New customer prices became effective January 1, 2014.

The increase includes improvements to existing power plants and wind forecasting, new Clackamas River fish-sorting facilities, a disaster-preparedness center, technology investments, employee benefit costs and compliance with new federal regulations. In addition, the order approves a capital structure of 50% debt and 50% equity, a return on equity of 9.75%, a cost of capital of 7.65%, and an average rate base of approximately $3.1 billion.

On February 13, 2014, PGE filed with the OPUC a 2015 General Rate Case, which is based on a 2015 test year. PGE requested an $81 million net increase in annual revenues, representing an approximate 4.6% overall increase in customer prices. The net increase in annual revenues consists of the following (in millions):

New generating plants:		
Port Westward Unit 2	$	51
Tucannon River		47
Base business cost increase		12
Less: customer credits [1]		(29)
Annual revenue net increase	$	81

(1) Includes approximately $17 million for the return of $50 million over three years, 2015 through 2017, for the settlement of a legal matter concerning costs associated with the operation of the ISFSI at Trojan. Also includes credits related to the return of ISFSI tax credits to customers and additional BPA Regional Power Act refund to residential customers.

PGE is proposing a capital structure of 50% debt and 50% equity, a return on equity of 10%, a cost of capital of 7.78%, and an average rate base of approximately $3.9 billion.

Regulatory review of the 2015 General Rate Case will continue throughout 2014, with a final order expected to be issued by the OPUC by mid-December 2014. New customer prices are expected to become effective in 2015, with the first price increase effective January 1 and two additional price increases effective as two new generating plants become operational, which is expected in the first half of 2015.

Capital Requirements and Financing—During 2013, PGE completed the competitive bidding processes for additional generation resources identified in its 2009 IRP. Pursuant to the request for proposals, one for capacity and energy (baseload) resources and one for renewable resources, the following resources were selected as the successful bids:

- In January, Port Westward Unit 2 (PW2), a flexible 220 MW natural gas-fired generating resource, was selected as the successful bid for the capacity resource;

- In June, Carty Generating Station (Carty), a 440 MW natural gas-fired generating plant, located adjacent to the Company's Boardman plant in eastern Oregon, was selected as the successful bid for the energy (baseload) resource; and

- In June, Tucannon River, a 267 MW wind farm, was selected as the successful bid for the renewable resource.

For additional information on these capital projects, see "*Capital Requirements*" in the Liquidity and Capital Resources section in this Item 7.

More than half of PGE's capital requirements in 2013 related to the construction of these new generation resources, with the remainder related to 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. During 2013, the combination of cash from operations in the amount of $544 million, and net proceeds from the issuances of equity and debt instruments in the amount of $67 million and $380 million, respectively, funded the Company's capital requirements of $656 million and contractual maturities of long-term debt of $100 million.

Capital expenditures in 2014 are expected to approximate $1 billion, which includes an estimated $675 million related to the three new generation resources under construction. PGE expects to fund 2014 estimated capital requirements with a combination of cash from operations, which is expected to range from $500 million to $520 million, and issuances of shares pursuant to an equity forward sale agreement (EFSA) and long-term debt securities, which is dependent upon the timing and amount of capital expenditures. For information concerning the EFSA, see Note 12, Equity-based Plans, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data." and for additional related information, see the Liquidity and Debt and Equity Financings sections of this Item 7.

Legal, Regulatory and Environmental Matters—PGE is a party to certain proceedings, the ultimate outcome of which could have a material impact on the results of operations and cash flows in future reporting periods. Such proceedings include, but are not limited to, matters related to:

- Recovery of the Company's investment in its closed Trojan plant;
- Claims for refunds related to wholesale energy sales during 2000 - 2001 in the Pacific Northwest Refund proceeding; and
- An investigation of environmental matters at Portland Harbor.

For additional information regarding the above and other matters, see Note 18, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

The following discussion highlights certain regulatory items, which have impacted the Company's revenues, results of operations, or cash flows for 2013, or have affected customer prices, as authorized by the OPUC. In some cases, the Company 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. The OPUC issued an order on the 2013 AUT resulting in an estimated 2% decrease in customer prices as a result of expected lower power costs. The new prices became effective January 1, 2013 and were expected to result in a decline of approximately $36 million in annual revenues compared to 2012. Actual NVPC for 2013 were $11 million above what was expected in the AUT.

The 2014 AUT was approved by the OPUC and became effective January 1, 2014, with an expected reduction in annual revenues of approximately $17 million based on lower forecasted power costs. This amount is included in the overall $61 million revenue increase authorized by the OPUC in the Company's 2014 General Rate Case.

In June 2013, the Company submitted the 2012 results of the PCAM to the OPUC for final regulatory review and determination of any customer refund or collection. Based on a regulated earnings test, no refund or collection resulted, and in October 2013, the OPUC issued an order to such effect. For further information, see "*Power Operations*" in the Operating Activities section of this Overview, above.

Renewable Resource Costs—Pursuant to a renewable adjustment clause (RAC) mechanism, PGE can recover in customer prices prudently incurred costs of renewable resources that are expected to be placed in service in the current year. The Company may submit a filing to the OPUC by April 1st each year, with prices expected to become effective January 1st of the following year. As part of the RAC, the OPUC has authorized the deferral of eligible costs not yet included in customer prices until the January 1st effective date.

PGE did not submit a RAC filing to the OPUC in 2013 as it did not place renewable resources into service. The Company expects to utilize the RAC to recover certain costs associated with Tucannon River, construction of which began in 2013.

Decoupling Mechanism—The decoupling mechanism, which the OPUC has authorized through 2016, 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 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.

As part of the Company's 2014 General Rate Case, the OPUC approved a change in the refund or collection period to begin January 1. Collection or refund is expected to occur over a one-year period, which, for the 2013 year, will begin January 1, 2015. The Company recorded an estimated collection of $5 million during the year ended December 31, 2013, which resulted from variances between actual weather adjusted use per customer and that projected in the 2011 General Rate Case.

Capital deferral—In the 2011 General Rate Case, the OPUC authorized the Company to defer the costs associated with four capital projects that were not completed at the time the 2011 General Rate Case was approved. In 2012, PGE recorded a regulatory asset of $16 million for potential recovery in customer prices with an offsetting credit to Depreciation and amortization expense. The OPUC authorized recovery of the deferred costs, with a resulting tariff effective over a one year period beginning January 1, 2014. The Company deferred an additional $18 million of costs associated with these projects during 2013 and plans to file for recovery of these deferred costs, subject to an earnings test, in July 2014 with new customer prices expected to be effective in January 2015.

Boardman Operating Life Adjustment—In PGE's 2011 General Rate Case, the OPUC approved a tariff that provided a mechanism for future consideration of customer price changes related to the recovery of the Company's remaining investment in Boardman over a shortened operating life. Pursuant to the tariff, the OPUC approved recovery of increased depreciation expense reflecting a change in the retirement date of Boardman from 2040 to 2020 and estimated decommissioning costs, with new prices effective July 1, 2011. As part of the 2014 General Rate Case, the incremental depreciation expense that resulted from the shortened Boardman life was rolled into base customer prices, while recovery of the decommissioning costs continue under this separate tariff. The OPUC is currently considering the request for recovery of additional decommissioning costs that resulted from the acquisition of the additional 15% interest in Boardman on December 31, 2013. The tariff also provides for annual updates to decommissioning revenue requirements with revised prices to take effect each January 1.

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.

The consolidated statements of income for the years presented (dollars in millions):

	Years Ended December 31,					
	2013		2012		2011	
	Amount	As % of Rev	Amount	As % of Rev	Amount	As % of Rev
Revenues, net	$ 1,810	100%	$ 1,805	100%	$ 1,813	100%
Purchased power and fuel	757	42	726	40	760	42
Gross margin	1,053	58	1,079	60	1,053	58
Other operating expenses:						
Production and distribution	225	12	211	12	201	11
Cascade Crossing transmission project	52	3	—	—	—	—
Administrative and other	219	12	216	12	218	12
Depreciation and amortization	248	14	248	14	227	13
Taxes other than income taxes	103	6	102	5	98	5
Total other operating expenses	847	47	777	43	744	41
Income from operations	206	11	302	17	309	17
Interest expense, net (1)	101	5	108	6	110	6
Other income:						
Allowance for equity funds used during construction	13	1	6	—	5	—
Miscellaneous income, net	7	—	4	—	1	—
Other income, net	20	1	10	—	6	—
Income before income taxes	125	7	204	11	205	11
Income tax expense	21	1	64	3	58	3
Net income	104	6	140	8	147	8
Less: net loss attributable to noncontrolling interests	(1)	—	(1)	—	—	—
Net income attributable to Portland General Electric Company	$ 105	6%	$ 141	8%	$ 147	8%

(1) Includes an allowance for borrowed funds used during construction of $7 million in 2013, $4 million in 2012, and $3 million in 2011.

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

	Years Ended December 31,					
	2013		2012		2011	
Revenues[1] (dollars in millions):						
Retail:						
Residential	$ 861	48%	$ 860	48%	$ 877	48%
Commercial	619	34	633	34	635	35
Industrial	217	12	226	13	226	13
Subtotal	1,697	94	1,719	95	1,738	96
Other accrued (deferred) revenues, net	(5)	—	4	—	(16)	(1)
Total retail revenues	1,692	94	1,723	95	1,722	95
Wholesale revenues	80	4	49	3	60	3
Other operating revenues	38	2	33	2	31	2
Total revenues	$ 1,810	100%	$ 1,805	100%	$ 1,813	100%
Energy deliveries[2] (MWh in thousands):						
Retail:						
Residential	7,702	35%	7,505	35%	7,733	36%
Commercial	7,441	34	7,402	35	7,419	35
Industrial	4,276	20	4,283	20	4,193	19
Total retail energy deliveries	19,419	89	19,190	90	19,345	90
Wholesale energy deliveries	2,353	11	2,249	10	2,142	10
Total energy deliveries	21,772	100%	21,439	100%	21,487	100%
Average number of retail customers:						
Residential	728,481	87%	723,440	87%	719,977	87%
Commercial	104,385	13	103,766	13	102,940	13
Industrial	263	—	261	—	255	—
Total	833,129	100%	827,467	100%	823,172	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) Includes both energy sold to retail customers and energy deliveries to those commercial and industrial customers that purchase their energy from ESSs.

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

	Years Ended December 31,					
	2013		2012		2011	
Sources of energy (MWh in thousands):						
Generation:						
Thermal:						
Coal	4,070	19%	3,610	17%	4,125	19%
Natural gas	3,375	16	2,882	14	2,138	10
Total thermal	7,445	35	6,492	31	6,263	29
Hydro	1,646	8	1,943	9	1,933	9
Wind	1,200	5	1,125	5	1,216	6
Total generation	10,291	48	9,560	45	9,412	44
Purchased power:						
Term	6,472	31	7,382	35	6,252	29
Hydro	1,629	8	1,728	8	2,897	13
Wind	311	1	319	1	269	1
Spot	2,547	12	2,285	11	2,763	13
Total purchased power	10,959	52	11,714	55	12,181	56
Total system load	21,250	100%	21,274	100%	21,593	100%
Less: wholesale sales	(2,353)		(2,249)		(2,142)	
Retail load requirement	18,897		19,025		19,451	

Net income attributable to Portland General Electric Company for the year ended December 31, 2013 was $105 million, or $1.35 per diluted share, compared to $141 million, or $1.87 per diluted share, for the year ended December 31, 2012. The $36 million, or 26%, decrease in net income was primarily due to the charge to expense in 2013 of $52 million of previously capitalized costs related to Cascade Crossing, $17 million of incremental replacement power costs related to three unplanned plant outages, and an industrial customer refund of $9 million related to cumulative over-billings over a period of several years. These three items are the primary drivers for the reduction in the Company's income tax expense for 2013, which had a favorable impact to net income when compared to 2012. In addition, higher repair costs at the Company's generating plants, higher operating and maintenance costs related to PGE's transmission and distribution system, a 4% increase in average variable power cost per MWh, and higher pension costs all contributed to the decrease in net income. A 3% increase in retail energy deliveries to residential customers primarily resulting from more extreme weather in 2013, an increase in the allowance for debt and equity funds used for construction, as well as lower interest expense partially offset the decreases to net income.

Net income attributable to Portland General Electric Company for the year ended December 31, 2012 was $141 million, or $1.87 per diluted share, compared to $147 million, or $1.95 per diluted share, for the year ended December 31, 2011. The $6 million, or 4%, decrease in net income was primarily driven by the 3% decrease in retail energy deliveries to residential customers, primarily resulting from warmer weather during the heating season, which was partially offset by a 3% decrease in average variable power cost per MWh, which was driven by lower wholesale power and natural gas prices. Actual NVPC was $17 million below the baseline NVPC established in the AUT for 2012, compared to $34 million below the baseline in 2011. In addition, a higher effective income tax rate and increased pension expense contributed to the decrease in net income. Offsetting these decreases was the deferral of $15 million of costs related to four capital projects during 2012.

2013 Compared to 2012

Revenues increased $5 million in 2013 compared with 2012 as a result of the items discussed below.

Total retail revenues decreased $31 million, or 2%, in 2013 compared with 2012, primarily due to the net effect of the following:

- A $38 million decrease resulting from lower average prices due primarily to lower expected power costs as established in the Company's 2013 AUT and a larger portion of energy deliveries going to customers who purchase their energy from ESSs;
- A $9 million decrease related to an industrial customer refund for cumulative over-billings that occurred over a period of several years as a result of a meter configuration error. Management believes the customer billing error is not material to any past reporting period. The Company corrected this matter in the second quarter of 2013 through an out of period adjustment; and
- A $4 million decrease related to the Company's PCAM, as the estimated refund to customers related to the 2011 PCAM was reduced in 2012, with no estimated refund to or collection from customers recorded in 2013; partially offset by
- A $20 million increase related to higher volumes of energy deliveries driven by more extreme weather in 2013 compared to 2012. Residential energy deliveries were up 2.6% in 2013, while commercial and industrial deliveries combined were comparable to 2012.

Both heating and cooling degree-days in 2013 exceeded the 15-year averages (as provided by the National Weather Service, as measured at Portland International Airport), while in 2012, both heating and cooling degree-days fell below the 15-year averages. The following table indicates the number of actual heating and cooling degree-days for the periods presented, along with the 15-year averages:

	Heating Degree-Days			Cooling Degree-Days		
	2013	2012	Increase/ (decrease)	2013	2012	Increase/ (decrease)
1st quarter	1,902	1,967	(3)%	—	—	—%
2nd quarter	593	709	(16)	82	40	105
3rd quarter	90	58	55	457	395	16
4th quarter	1,801	1,435	26	—	1	(100)
	4,386	4,169	5	539	436	24
15-year annual average	4,239	4,235	—	454	456	—
Increase (decrease) from the 15-year annual average	3%	(2)%		19%	(4)%	

On a weather adjusted basis, retail energy deliveries in 2013 were comparable to 2012, with energy deliveries to residential customers increasing by 1%, and energy deliveries to commercial and industrial customers combined were comparable to prior year. PGE projects that retail energy deliveries for 2014 will increase approximately 1% from 2013 weather adjusted levels, after allowing for energy efficiency and conservation efforts.

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

In 2013, the $31 million, or 63%, increase in wholesale revenues from 2012 consisted of $29 million related to a 55% increase in average wholesale price and $2 million related to a 5% increase in wholesale sales volume.

Other operating revenues increased $5 million, or 15%, in 2013 from 2012, primarily due to an increase in gains on the sale of excess natural gas, and an increase in the sale of oil, not needed for operations.

Purchased power and fuel expense includes the cost of power purchased and fuel used to generate electricity to meet PGE's retail load requirements, as well as the cost of settled electric and natural gas financial contracts. In 2013, Purchased power and fuel expense increased $31 million, or 4%, from 2012, largely due to a 4% increase in average variable power cost per MWh. Such increase was driven by a 16% increase in the cost of purchased power and a decrease in energy received from hydroelectric projects. In addition, during the second half of 2013, the Company experienced unplanned plant outages at three of its generating facilities and incurred $17 million of incremental replacement power costs. A 10% decrease in the average cost per MWh of power generated partially offset the increases. The average variable power cost increased to $35.61 per MWh in 2013 from $34.25 per MWh in 2012.

Hydroelectric energy, from PGE-owned hydroelectric projects and from mid-Columbia projects combined, decreased 11% during 2013 from 2012 due to less favorable hydro conditions in 2013. In each of 2013 and 2012 total hydroelectric energy received exceeded that projected in the Company's AUT by approximately 1% for 2013 and 11% for 2012. Based on recent forecasts of regional hydro conditions in 2014, energy from hydro resources is expected to be below normal levels.

The following table presents the forecast of the April-to-September 2014 runoff (issued February 12, 2014) compared to the actual runoffs for 2013 and 2012 (as a percentage of normal, as measured over the 30-year period from 1971 through 2000):

	Runoff as a Percent of Normal *		
Location	**2014 Forecast**	**2013 Actual**	**2012 Actual**
Columbia River at The Dalles, Oregon	95%	100%	126%
Mid-Columbia River at Grand Coulee, Washington	97	108	129
Clackamas River at Estacada, Oregon	92	102	133
Deschutes River at Moody, Oregon	96	98	118

* Volumetric water supply forecasts for the Pacific Northwest region are prepared by the Northwest River Forecast Center in conjunction with the Natural Resources Conservation Service and other cooperating agencies.

Energy from PGE-owned wind generating resources (Biglow Canyon) increased 7% from 2012 due to unfavorable wind conditions in 2012, and represented 6% of the Company's retail load requirement in 2013 and in 2012. Energy received from Biglow Canyon fell short of projections included in the Company's AUT by approximately 15% in 2013 compared to 20% in 2012.

Actual NVPC consists of Purchased power and fuel expense net of Wholesale revenues and was comparable for 2013 relative to 2012. A decrease driven by a 55% increase in the average price per MWh of wholesale power sales, was largely offset by a 4% increase in the average variable power cost per MWh. For 2013, actual NVPC was $11 million above baseline NVPC, compared with $17 million below baseline NVPC for 2012.

Production and distribution expense increased $14 million, or 7%, in 2013 compared to 2012. The increase is largely due to $5 million related to planned overhaul and repair costs at Colstrip and Coyote Springs, $3 million related to increased delivery system repair and restoration work, $3 million for the warranty extension related to the third phase of Biglow Canyon, and $2 million of expense associated with the Company's benchmark proposals that were not selected in the RFP process for new generation.

Cascade Crossing transmission project reflects $52 million of costs expensed in the second quarter of 2013, which were previously recorded as construction work-in-progress (CWIP). For additional information, see "*Electric*

Utility Plant" in Note 2, Summary of Significant Accounting Policies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Administrative and other expense increased $3 million, or 1%, in 2013 compared to 2012, as a $6 million increase in employee pension expense, driven by a lower discount rate, was partially offset by amortization of $3 million in 2012 of deferred costs related to the Trojan refund matter.

Depreciation and amortization expense in 2013 was comparable to 2012, as a $7 million increase resulting from capital additions was largely offset by an increase in costs deferred related to four capital projects as authorized in the Company's 2011 General Rate Case, a decrease in the asset retirement obligation (ARO) resulting from the decommissioning of the Bull Run hydro facility in 2012, and the amortization in 2012 of tax credits related to the ISFSI located at the former Trojan site.

Interest expense decreased $7 million, or 6%, in 2013 compared with 2012, consisting of $4 million related to the timing of the 2013 maturities and issuances of long-term debt, and $3 million related to an increase in the allowance for borrowed funds used for construction, which was driven by a higher average CWIP balance resulting from the commencement of the construction of PW2, Carty, and Tucannon River Wind Farm (Tucannon River) in 2013.

Other income, net increased $10 million, or 100%, in 2013 compared with 2012, primarily due to a $7 million increase in the allowance for equity funds used for construction from the higher average CWIP balance, as well as an increase in earnings from the non-qualified benefit plan trust assets.

Income tax expense decreased $43 million, or 67%, in 2013, compared to 2012, with the effective tax rate decreasing to 16.8% for 2013 from 31.4% for 2012. These decreases are primarily due to a decrease in the pre-tax income for 2013 compared with 2012, which was driven by the $52 million charge to expense in 2013 related to Cascade Crossing, combined with other unfavorable impacts to 2013 pre-tax income. Also contributing to the decreases was an increase to deferred tax balances in 2012 for a change in the Company's composite state tax rate and an increase in production tax credits in 2013.

2012 Compared to 2011

Revenues decreased $8 million in 2012 compared to 2011 as a result of the net effect of the items discussed below.

Total retail revenues were comparable with the prior year primarily due to the net effect of the following items:

- An $18 million increase as a result of credits provided to customers in 2011 (offset in Depreciation and amortization), with no comparable refund in 2012. The customer credits were the result of tax credits the Company had accumulated over several years in relation to the ISFSI located at the former Trojan site;
- A $14 million increase related to the PCAM, as an estimated refund to customers in the amount of $10 million was recorded in 2011 compared with a $4 million reduction in the estimated PCAM refund for the 2011 year recorded in 2012. No estimated refund or collection was recorded under the PCAM related to the 2012 year. For further discussion of the PCAM, see "Purchased power and fuel expense," below; and
- A $17 million increase resulting from supplemental tariffs and several small regulatory items, which are primarily offset in other line items in the statements of income and thus have no effect on income. The largest contributors amounted to $5 million for the recovery of costs under the solar Feed-In Tariff and $3 million for the recovery of expenses related to the Trojan refund; offset by
- A $34 million decrease related to the volume of retail energy sold and delivered. Residential volumes were down 3%, primarily driven by warmer temperatures during the heating season in 2012. Deliveries to industrial customers were up 2% due largely to increased demand from the high technology sector; and
- A $15 million decrease related to changes in the average retail price, resulting primarily from tariff changes effective January 1, 2012 as authorized by the OPUC including lower anticipated power costs included in the AUT partially offset by a $7 million net annual increase related to the tariff for recovery of Boardman

over a shortened operating life. Incremental revenues under the Boardman tariff for the full year 2012 were $14 million compared with $7 million for the last six months of 2011.

Heating degree-days in 2012 were 2% less than the 15-year average provided by the National Weather Service, as measured at Portland International Airport, and decreased 10% compared with 2011, which had 10% more heating degree-days that the 15-year average. The following table indicates the number of heating and cooling degree-days for the periods presented, along with 15-year averages:

	Heating Degree-Days			Cooling Degree-Days		
	2012	**2011**	**Increase/ (decrease)**	**2012**	**2011**	**Increase/ (decrease)**
1st quarter	1,967	1,974	— %	—	—	—%
2nd quarter	709	946	(25)	40	16	150
3rd quarter	58	51	14	395	346	14
4th quarter	1,435	1,679	(15)	1	—	—
	4,169	4,650	(10)	436	362	20
15-year annual average	4,235	4,219	—	456	464	(2)
Increase (decrease) from the 15-year annual average	(2)%	10%		(4)%	(22)%	

On a weather adjusted basis, retail energy deliveries in 2012 increased 0.6% compared to 2011, with deliveries to residential, commercial, and industrial customers increasing by 0.4%, 0.2%, and 1.7%, respectively.

Wholesale revenues in 2012 decreased $11 million, or 18%, from 2011 and consisted of $14 million related to a 22% decline in the average wholesale price, driven by lower electricity market prices due to the relatively low price of natural gas and a surplus of hydro generation in the region, partially offset by $3 million related to a 5% increase in wholesale energy sales volume.

Purchased power and fuel expense decreased $34 million, or 4%, in 2012 from 2011, with $19 million related to a 3% decrease in average variable power cost per MWh, partially offset by $11 million related to a 1% decrease in total system load. The decrease in the average variable power cost to $34.25 per MWh in 2012 from $35.15 per MWh in 2011 was largely due to lower wholesale power prices resulting from favorable hydro conditions and low natural gas prices.

Hydroelectric energy, from PGE-owned hydroelectric projects and from mid-Columbia projects combined, decreased 24% during 2012 from 2011, which was primarily the result of the expiration of a contract related to a mid-Columbia project that represented approximately 156 MW of capacity. Favorable hydro conditions in both years resulted in total hydroelectric energy received for each respective year exceeding that projected in the Company's AUT by approximately 11% for 2012 and 13% for 2011.

The following table presents the actual of the April-to-September runoff for 2012 and 2011 (as a percentage of normal, as measured over the 30-year period from 1971 through 2000):

	Runoff as a Percent of Normal *	
Location	**2012 Actual**	**2011 Actual**
Columbia River at The Dalles, Oregon	126%	135%
Mid-Columbia River at Grand Coulee, Washington	129	123
Clackamas River at Estacada, Oregon	133	135
Deschutes River at Moody, Oregon	118	120

* Volumetric water supply forecasts for the Pacific Northwest region are prepared by the Northwest River Forecast Center in conjunction with the Natural Resources Conservation Service and other cooperating agencies.

Energy received from PGE-owned wind generating resources (Biglow Canyon) decreased 7% from 2011, and represented 6% of the Company's retail load requirement in 2012 and in 2011. The decrease from prior year was due to unfavorable wind conditions, with energy received from Biglow Canyon falling short of projections included in the Company's AUT by approximately 20% in 2012 compared with 13% in 2011.

Actual NVPC decreased approximately $23 million for 2012 compared with 2011, largely due to a 3% decrease in average variable power cost per MWh combined with a 1% decrease in total system load. For 2012, actual NVPC was $17 million below baseline NVPC, compared with $34 million below baseline NVPC for 2011.

Production and distribution expense increased $10 million, or 5%, in 2012 compared to 2011, primarily due to the following:

- A $4 million increase due to higher maintenance costs of the Company's generating plants and distribution system;
- A $3 million increase due to an insurance recovery related to the Selective Water Withdrawal project recorded in 2011; and
- A $3 million increase due to higher delivery system labor costs.

Administrative and other expense increased $2 million, or 1%, in 2012 compared to 2011, primarily due to the following:

- A $6 million decrease due to expenses related to information technology upgrades in 2011;
- A $3 million decrease related to higher write-offs of uncollectible customer accounts in 2011;
- A $2 million decrease in compensation expense primarily due to lower incentive compensation in 2012; partially offset by
- A $7 million increase in employee pension expenses resulting from a lower discount rate and lower return on pension trust assets; and
- A $3 million increase due to the amortization of deferred expenses related to the Trojan refund (offset in Revenues).

Depreciation and amortization expense decreased $21 million, or 9%, in 2012 compared to 2011, due largely to the net effect of the following:

- An $18 million increase related to the amortization of customer refunds for the ISFSI tax credits in 2011 (offset in Revenues);
- A $13 million increase in depreciation expense related to a shorter operating life for Boardman (effective July 2011 and offset in Revenues), and other capital additions including emissions control retrofits at Boardman;
- A $5 million increase in amortization related to the Solar Feed-In Tariff (offset in Revenues); partially offset by
- A $15 million decrease related to the 2012 deferral of costs related to four capital projects as approved in the 2011 General Rate Case.

Taxes other than income taxes increased $4 million, or 4%, in 2012 compared to 2011, primarily due to higher property taxes resulting from increased property values and tax rates. Also contributing to the increase were higher franchise fees.

Interest expense decreased $2 million, or 2%, in 2012 compared to 2011, primarily due to lower interest resulting from a lower average outstanding balance of long-term debt.

Other income, net was $10 million in 2012 compared to $6 million in 2011. The increase is primarily due to higher income from the non-qualified benefit plan trust.

Income tax expense increased $6 million, or 10%, in 2012 compared to 2011, with effective tax rates of 31.4% and 28.3% for 2012 and 2011, respectively. The increase in the effective tax rate is primarily due to the change in apportionment of state income taxes, which resulted in an increase to deferred taxes. The change in apportionment was caused by lower wholesale sales in Washington, which has no corporate income tax, resulting in more taxable income being apportioned to Oregon.

Liquidity and Capital Resources

Discussions, forward-looking statements and projections in this section, and similar statements in other parts of the Form 10-K, are subject to PGE's assumptions regarding the availability and cost of capital. See "Current 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 scheduled." in Item 1A.—"Risk Factors."

Capital Requirements

The following table indicates actual capital expenditures for 2013 and future debt maturities and projected cash requirements for 2014 through 2018 (in millions, excluding allowance for funds used during construction, or AFDC):

	Years Ending December 31,					
	2013	2014	2015	2016	2017	2018
Ongoing capital expenditures	$ 315	$ 325	$ 290	$ 290	$ 250	$ 240
Port Westward Unit 2	155	130	15	—	—	—
Carty Generating Station	135	155	115	45	—	—
Tucannon River Wind Farm	95	390	15	—	—	—
Hydro licensing and construction	20	40	35	5	5	5
Total capital expenditures	$ 720 (1)	$ 1,040	$ 470	$ 340	$ 255	$ 245
Long-term debt maturities	$ 100	$ —	$ 70	$ 67	$ 58	$ 75

(1) Amounts shown include removal costs, which are included in other net operating activities in the consolidated statements of cash flows.

For a discussion concerning PGE's ability to fund its future capital requirements, see "Debt and Equity Financings" in this Item 7.

Ongoing capital expenditures—Consists of upgrades to and replacement of transmission, distribution, and generation infrastructure as well as new customer connections.

Port Westward Unit 2—In January 2013, PGE's PW2 flexible generating resource was selected as the successful bid for the capacity resource in the Company's RFP for energy and capacity resources. PW2 is a 220 MW natural gas-fired plant that will be located adjacent to Port Westward and Beaver near Clatskanie, Oregon. Total cost of PW2 is estimated at $300 million, excluding AFDC, and the facility is expected to be online in the first quarter of 2015. Construction commenced in May 2013, and as of December 31, 2013, $162 million, including AFDC, is included in CWIP for PW2.

Carty Generating Station—In June 2013, Carty, a proposed 440 MW natural gas-fired power plant in Eastern Oregon, located adjacent to Boardman, was selected as the successful bid for the energy (baseload) resource in the Company's RFP for energy and capacity resources. Total cost of Carty is estimated at $450 million, excluding

AFDC, and the facility is expected to be online in 2016. Construction commenced in January 2014, and as of December 31, 2013, $138 million, including AFDC, is included in CWIP for Carty.

Tucannon River Wind Farm—In June 2013, Tucannon River in southeastern Washington was selected as the successful bid for the renewable resource in the Company's RFP for renewable resources. Tucannon River, with a nameplate capacity of 267 MW, consisting of 116 turbines each with a generating capacity of 2.3 MWs, is expected to be in service in the first half of 2015 at an estimated cost of $500 million, excluding AFDC. Construction commenced in September 2013, and as of December 31, 2013, $99 million, including AFDC, is included in CWIP for Tucannon River.

Hydro licensing and construction—PGE's hydroelectric projects are operated pursuant to FERC licenses issued under the Federal Power Act. The licenses for the hydroelectric projects expire as follows: Clackamas River, 2055; Willamette River, 2035; and Deschutes River, 2055. Capital spending requirements reflected in the table above relate primarily to modifications to the Company's various hydro facilities to enhance fish passage and survival, as required by conditions contained in the operating licenses.

Liquidity

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

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

	Years Ended December 31,		
	2013	**2012**	**2011**
Cash and cash equivalents, beginning of year	$ 12	$ 6	$ 4
Net cash provided by (used in):			
Operating activities	544	494	453
Investing activities	(692)	(294)	(299)
Financing activities	243	(194)	(152)
Net change in cash and cash equivalents	95	6	2
Cash and cash equivalents, end of year	$ 107	$ 12	$ 6

2013 Compared to 2012

Cash Flows from Operating Activities—Cash flows from operating activities are generally determined by the amount and timing of cash received from customers and payments made to vendors, as well as the nature and amount of non-cash items, including depreciation and amortization, deferred income taxes, and pension and other postretirement benefit costs included in net income during a given period. The $50 million increase in cash flows from operating activities in 2013 compared to 2012 was largely due to the receipt of $44 million in the third quarter of 2013 related to the settlement of a legal matter concerning costs associated with the operation of the ISFSI. Such amount was transferred into the Nuclear decommissioning trust, and consequently is also reflected as an outflow of cash for investing activities. The net change in working capital items, partially offset by a decrease in net income after the consideration of non-cash items, also contributed to the increase in cash flows from operating activities.

Cash provided by operations includes the recovery in customer prices of non-cash charges for depreciation and amortization. The Company estimates that such charges in 2014 will range from $300 million to $310 million.

Combined with all other sources, cash provided by operations in 2014 is estimated to range from $500 million to $520 million. This estimate anticipates no change in margin deposits held by brokers as of December 31, 2013, which is based on both the timing of contract settlements and projected energy prices. The remaining estimated cash flows from operations in 2014 is expected from normal operating activities.

Cash Flows from Investing Activities—Cash flows used in investing activities consist primarily of capital expenditures related to new construction and improvements to PGE's distribution, transmission, and generation facilities. The $398 million increase in net cash used in investing activities in 2013 compared to 2012 was primarily due to a $353 million increase in capital expenditures, largely due to the construction of three new generation projects (PW2, Carty and Tucannon River), and a $44 million contribution to the Nuclear decommissioning trust in the third quarter of 2013. For additional information regarding the contribution to the Nuclear decommissioning trust, see Note 7, Asset Retirement Obligations, in the Notes to Consolidated Financial Statements in Item 8. —"Financial Statements and Supplementary Data."

The Company plans approximately $1 billion of capital expenditures in 2014 related to upgrades to and replacement of transmission, distribution and generation infrastructure, including $675 million related to the construction of three new generation resources. PGE plans to fund the 2014 capital expenditures with the cash expected to be generated from operations during 2014, as discussed above, as well as with the issuance of debt and equity securities. For additional information, see "*Capital Requirements*" and "*Debt and Equity Financings*" in the Liquidity and Capital Resources section of this Item 7.

Cash Flows from Financing Activities—Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. During 2013, cash provided by such activities consisted of net proceeds received from the issuances of common stock in the aggregate amount of $67 million and FMBs in the aggregate amount of $377 million, partially offset by the repayment of FMBs of $100 million and commercial paper of $17 million, and payment of dividends of $84 million. During 2012, net cash used in financing activities consisted of the repayment of FMBs of $100 million, payment of dividends of $81 million and net maturities of commercial paper of $13 million.

2012 Compared to 2011

Cash Flows from Operating Activities—The $41 million increase in cash provided by operating activities in 2012 compared to 2011 was largely due to the impact of a combined contribution of $42 million to the pension plan and the voluntary employees' beneficiary association trusts (VEBAs) in 2011 and a decrease in margin deposit requirements, partially offset by a decrease in net income after the consideration of non-cash items. The VEBAs fund the benefits of the Company's non-contributory postretirement health and life insurance plans.

Cash Flows from Investing Activities—The $5 million decrease in cash used in investing activities in 2012 compared to 2011 was primarily due to proceeds received in the amount of $10 million for the sale of a solar power facility during the first quarter of 2012, partially offset by a 1% increase in capital expenditures.

Cash Flows from Financing Activities—During 2012, net cash used in financing activities consisted of the repayment of FMBs of $100 million, the payment of dividends of $81 million and net maturities of commercial paper of $13 million. During 2011, net cash used in financing activities primarily consisted of the payment of dividends of $79 million and the repayment of long-term debt of $80 million, including the premium paid, partially offset by net issuances of commercial paper of $11 million.

Dividends on Common Stock

The following table indicates common stock dividends declared in 2013:

Declaration Date	Record Date	Payment Date	Declared Per Common Share
February 20, 2013	March 25, 2013	April 15, 2013	$ 0.270
May 22, 2013	June 25, 2013	July 15, 2013	0.275
July 31, 2013	September 25, 2013	October 15, 2013	0.275
October 30, 2013	December 26, 2013	January 15, 2014	0.275

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

Credit Ratings and Debt Covenants

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

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

In January 2014, Moody's upgraded their credit ratings on the Company's FMBs to 'A1' from 'A2' and senior unsecured debt to 'A3' from 'Baa1,' with no changes to their rating on PGE's commercial paper or their outlook on PGE. The credit rating upgrades were primarily driven by Moody's favorable view of the relative credit support of the United States regulatory framework. The upgrades also reflect Moody's acknowledgement of a high degree of credit support offered by the OPUC through a suite of cost recovery mechanisms, including forecasted test years, revenue decoupling and the ability to recover financing costs, commensurate with the spend, of certain renewable projects, and Moody's view that these recovery features provide predictability and stability of PGE's cash flows.

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

As of December 31, 2013, PGE had posted approximately $38 million of collateral with these counterparties, consisting of $9 million in cash and $29 million in letters of credit, $7 million of which is related to master netting agreements. Based on the Company's energy portfolio, estimates of energy market prices, and the level of collateral outstanding as of December 31, 2013, the approximate amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is approximately $80 million and decreases to approximately $34 million by December 31, 2014. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade is approximately $190 million and decreases to approximately $104 million by December 31, 2014.

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

The issuance of FMBs requires that PGE meet earnings coverage and security provisions set forth in the Indenture of Mortgage and Deed of Trust securing the bonds. PGE estimates that on December 31, 2013, under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust, the Company could have issued up to approximately $63 million of additional FMBs. PGE expects that this amount will increase in June 2014 when the impact of the $52 million expense related to Cascade Crossing, recorded in June 2013, will no longer be applicable to this issuance test. Accordingly, PGE does not expect this test to adversely affect PGE’s ability to obtain sufficient financing to satisfy its capital requirements in 2014. Any issuances of FMBs would be subject to market conditions and amounts could be further limited by regulatory authorizations or by covenants and tests contained in other financing agreements. PGE also has the ability to release property from the lien of the Indenture of Mortgage and Deed of Trust under certain circumstances, including bond credits, deposits of cash, or certain sales, exchanges or other dispositions of property.

PGE’s credit facilities contain customary covenants and credit provisions, including a requirement that limits consolidated indebtedness, as defined in the credit agreements, to 65% of total capitalization (debt to total capital ratio). As of December 31, 2013, the Company’s debt to total capital ratio, as calculated under the credit agreements, was 51.3%.

Debt and Equity Financings

PGE’s ability to secure sufficient long-term capital at a reasonable cost is determined by its financial performance and outlook, capital expenditure requirements, alternatives available to investors, and other factors. The Company’s ability to obtain and renew such financing depends on its credit ratings, as well as on credit markets, both generally and for electric utilities in particular. Management believes that the availability of credit facilities, the expected ability to issue long-term debt and equity securities, and cash expected to be generated from operations provide sufficient liquidity to meet the Company’s anticipated capital and operating requirements for the foreseeable future. However, the Company’s ability to issue long-term debt and equity could be adversely affected by changes in capital market conditions. For 2014, PGE expects to fund estimated capital requirements with cash from operations and issuances of debt securities ranging from $350 million to $400 million and equity securities under the EFSA of approximately $285 million, with the actual timing and amount of such issuances dependent upon the timing and amount of capital expenditures.

Short-term Debt. PGE has approval from the FERC to issue short-term debt up to a total of $900 million through February 6, 2016 and currently has the following unsecured revolving credit facilities:

- A $400 million syndicated credit facility, which is scheduled to terminate in November 2018; and
- A $300 million syndicated credit facility, which is scheduled to terminate in December 2017.

These revolving credit facilities supplement operating cash flows and provide a primary source of liquidity. Pursuant to the terms of the agreements, the revolving credit facilities may be used for general corporate purposes, backup for commercial paper borrowings, and the issuance of standby letters of credit.

As of December 31, 2013, PGE had no borrowings outstanding under the revolving credit facilities, no commercial paper outstanding, and $37 million of letters of credit issued. As of December 31, 2013, the aggregate unused available credit under the revolving credit facilities was $663 million.

The Company also has two letter of credit facilities under which it may obtain letters of credit in an aggregate amount not to exceed $60 million. Under these facilities, an additional $37 million of letters of credit was outstanding as of December 31, 2013.

Long-term Debt. During 2013, PGE repaid a total of $100 million of FMBs, in accordance with the terms of the debt agreements, and issued a total of $380 million of FMBs, consisting of the following:

- In December, issued $50 million of 4.84% Series FMBs due 2048;
- In November, issued $105 million of 4.74% Series FMBs due 2042;
- In August, repaid $50 million of 5.625% Series FMBs and issued $75 million of 4.47% Series FMBs due 2043;
- In June, issued $150 million of 4.47% Series FMBs due 2044; and
- In April, repaid $50 million of 4.45% Series FMBs.

As of December 31, 2013, total long-term debt outstanding was $1,916 million, with no scheduled maturities in 2014. In addition, of the $27 million of Pollution Control Revenue Bonds held by the Company, PGE has the option to remarket $21 million through 2033 and retired $6 million in January 2014.

Equity. On June 11, 2013, PGE entered into an EFSA in connection with the public offering of 11,100,000 shares of its common stock, with an initial value of $317 million. Pursuant to the EFSA, a forward counterparty borrowed 11,100,000 shares of PGE's common stock from third parties and such borrowed shares were sold in a registered public offering. PGE receives proceeds from the sale of the common stock when the EFSA is physically settled. Through December 31, 2013, the Company had the following equity transactions in connection with the offering:

- On June 17, 2013, the underwriters exercised their over-allotment option in full and PGE issued 1,665,000 shares of common stock for net proceeds of $47 million; and
- On August 21, 2013, the Company issued 700,000 shares of common stock for net proceeds of $20 million.

As of December 31, 2013, the Company could have physically settled the EFSA by delivering 10,400,000 shares of PGE common stock to the forward counterparty in exchange for cash of $288 million. The Company anticipates physical settlement of the EFSA by delivery of newly issued shares on or before June 11, 2015. For additional information on the EFSA, see Note 12, Equity-based Plans, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Capital Structure. PGE's financial objectives include the balancing of debt and equity to maintain a low weighted average cost of capital while retaining sufficient flexibility to meet the Company's financial obligations. PGE attempts to maintain a common equity ratio (common equity to total consolidated capitalization, including current debt maturities) of approximately 50%. Achievement of this objective while sustaining sufficient cash flow is necessary to maintain acceptable credit ratings and allow access to long-term capital at attractive interest rates. The Company's common equity ratios were 48.7% and 51.1% as of December 31, 2013 and 2012, respectively.

Contractual Obligations and Commercial Commitments

The following indicates PGE's contractual obligations as of December 31, 2013 (in millions):

	2014	2015	2016	2017	2018	There-after	Total
Long-term debt	$ —	$ 70	$ 67	$ 58	$ 75	$1,646	$1,916
Interest on long-term debt (1)	107	105	100	99	94	1,392	1,897
Capital and other purchase commitments	710	113	40	2	2	67	934
Purchased power and fuel:							
Electricity purchases	240	159	150	125	126	683	1,483
Capacity contracts	22	23	22	2	2	1	72
Public Utility Districts	8	8	7	5	5	33	66
Natural gas	65	21	12	10	8	6	122
Coal and transportation	21	6	6	6	4	5	48
Pension plan contributions (2)	—	—	23	21	11	—	55
Operating leases	11	9	10	10	10	191	241
Total	$1,184	$ 514	$ 437	$ 338	$ 337	$4,024	$6,834

(1) Future interest on long-term debt is calculated based on the assumption that all debt remains outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect as of December 31, 2013.

(2) Contributions to the Company's pension plan are not estimated beyond 2018 due to significant uncertainty in financial market and demographic outcomes.

Other Financial Obligations

PGE has entered into long-term power purchase contracts with certain public utility districts in the state of Washington under which it has acquired a percentage of the output (Allocation) of three hydroelectric projects (the Priest Rapids, Wanapum and Wells hydroelectric projects). The Company is required to pay its proportionate share of the operating and debt service costs of the projects whether or not they are operable. The contracts further provide that, should any other purchaser of output default on payments as a result of bankruptcy or insolvency, PGE would be allocated a pro rata share of both the output and the operating and debt service costs of the defaulting purchaser. For the Wells project, PGE would be allocated up to a cumulative maximum of 25% of the defaulting purchaser's percentage Allocation. For the Priest Rapids and Wanapum projects, PGE would be allocated up to a cumulative maximum that would not adversely affect the tax exempt status of any outstanding debt.

Off-Balance Sheet Arrangements

In June 2013, PGE entered into an EFSA in connection with a registered public offering of its common stock. The Company may settle the EFSA with issuance of PGE common stock, for cash or net share settlement from time-to-time, in whole or part, through June 11, 2015. For additional information on the EFSA, see Note 12, Equity-based Plans, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

PGE has no other off-balance sheet arrangements other than outstanding letters of credit from time to time that have, or are reasonably likely to have, a material current or future effect on its consolidated financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Critical Accounting Policies

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

Regulatory Accounting

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

If future recovery of regulatory assets ceases to be probable, PGE would be required to write them off. Further, if PGE determines that all or a portion of its utility operations no longer meet the criteria for continued application of regulatory accounting, the Company would be required to write off those regulatory assets and liabilities related to operations that no longer meet requirements for regulatory accounting. Discontinued application of regulatory accounting would have a material impact on the Company's results of operations and financial position.

Asset Retirement Obligations

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

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

Revenue Recognition

Retail customers are billed monthly for electricity use based on meter readings taken throughout the month. At the end of each month, PGE estimates the revenue earned from the last meter read date through the last day of the month, which has not yet been billed to customers. Such amount, which is classified as Unbilled revenues in the Company's consolidated balance sheet, is calculated based on each month's actual net retail system load, the number of days from the last meter read date through the last day of the month, and current customer prices.

Contingencies

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

Price Risk Management

PGE engages in price risk management activities to manage exposure to commodity and foreign currency market fluctuations and to manage volatility in net power costs for its retail customers. The Company utilizes derivative instruments, which may include forward, futures, swap, and option contracts for electricity, natural gas, oil, and foreign currency. These derivative instruments are recorded at fair value, or "marked-to-market," in PGE's consolidated financial statements.

Fair value adjustments consist of reevaluating the fair value of derivative contracts at the end of each reporting period for the remaining term of the contract and recording any change in fair value in Net income for the period. Fair value is the present value of the difference between the contracted price and the forward market price multiplied by the total quantity of the contract. For option contracts, a theoretical value is calculated using Black-Scholes models that utilize price volatility, price correlation, time to expiration, interest rate and forward commodity price curves. The fair value of these options is the difference between the premium paid or received and the theoretical value at the fair value measurement date.

Determining the fair value of these financial instruments requires the use of prices at which a buyer or seller could currently contract to purchase or sell a commodity at a future date (termed "forward prices"). Forward price "curves" are used to determine the current fair market value of a commodity to be delivered in the future. PGE's forward price curves are created by utilizing actively quoted market indicators received from electronic and telephone brokers, industry publications, and other sources. Forward price curves can change with market conditions and can be materially affected by unpredictable factors such as weather and the economy. PGE's forward price curves are validated using broker quotes and market data from a regulated exchange and differences for any single location, delivery date and commodity are less than 5%.

Pension Plan

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

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

Changes in actuarial assumptions can also have a material effect on net periodic pension expense. A 0.25% reduction in the expected long-term rate of return on plan assets, or reduction in the discount rate, would have the effect of increasing the 2013 net periodic pension expense by approximately $2 million.

Fair Value Measurements

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

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

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

Risk Management Committee

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

Commodity Price Risk

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

The following table presents energy commodity derivative fair values as a net liability as of December 31, 2013 that are expected to settle in each respective year (in millions):

	2014	2015	2016	2017	2018	Thereafter	Total
Commodity contracts:							
Electricity	$ 11	$ 26	$ 12	$ 5	$ 5	$ 58	$ 117
Natural gas	25	10	14	10	—	—	59
	$ 36	$ 36	$ 26	$ 15	$ 5	$ 58	$ 176

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

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

Foreign Currency Exchange Rate Risk

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

As of December 31, 2013, a 10% change in the value of the Canadian dollar would result in an immaterial change in exposure for transactions that will settle over the next twelve months.

Interest Rate Risk

To meet short-term cash requirements, PGE has established a program under which it may from time to time issue commercial paper for terms of up to 270 days; such issuances are supported by the Company's unsecured revolving credit facilities. Although any borrowings under the commercial paper program subject the Company to fluctuations in interest rates, reflecting current market conditions, individual instruments carry a fixed rate during their respective terms. As of December 31, 2013, PGE had no borrowings outstanding under its revolving credit facilities and no commercial paper outstanding.

PGE currently has no financial instruments to mitigate risk related to changes in short-term interest rates, including those on commercial paper; however, it may consider such instruments in the future as considered necessary.

As of December 31, 2013, the total fair value and carrying amounts by maturity date of PGE's long-term debt are as follows (in millions):

	Total Fair Value	Carrying Amounts by Maturity Date					
		Total	2015	2016	2017	2018	There-after
First Mortgage Bonds	$ 1,948	$ 1,795	$ 70	$ 67	$ 58	$ 75	$ 1,525
Pollution Control Revenue Bonds	126	121	—	—	—	—	121
Total	$ 2,074	$ 1,916	$ 70	$ 67	$ 58	$ 75	$ 1,646

As of December 31, 2013, PGE had no long-term variable rate debt outstanding; accordingly, the Company's outstanding long-term debt is not subject to interest rate risk exposures.

Credit Risk

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

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

As of December 31, 2013, PGE's credit risk exposure is $6 million for commodity activities with externally-rated investment grade counterparties and matures in 2014. The credit risk is included in accounts receivable and price risk management assets, offset by related accounts payable and price risk management liabilities.

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

Omitted from the market risk exposures discussed above are long-term power purchase contracts with certain public utility districts in the state of Washington and with the City of Portland, Oregon. These contracts provide PGE with a percentage share of hydro facility output in exchange for an equivalent percentage share of operating and debt service costs. These contracts expire at varying dates through 2052. For additional information, see "*Public Utility Districts*" in Note 15, Commitments and Guarantees, in the Notes to Consolidated Financial Statements in Item 8. —"Financial Statements and Supplementary Data." Management believes that circumstances that could result in the nonperformance by these counterparties are remote.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

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

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of
Portland General Electric Company
Portland, Oregon

We have audited the accompanying consolidated balance sheets of Portland General Electric Company and subsidiaries (the "Company") as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2013. We also have audited the Company's internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control-Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Portland General Electric Company and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control-Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 13, 2014

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

	Years Ended December 31,		
	2013	**2012**	**2011**
Revenues, net	$ 1,810	$ 1,805	$ 1,813
Operating expenses:			
Purchased power and fuel	757	726	760
Production and distribution	225	211	201
Cascade Crossing transmission project	52	—	—
Administrative and other	219	216	218
Depreciation and amortization	248	248	227
Taxes other than income taxes	103	102	98
Total operating expenses	1,604	1,503	1,504
Income from operations	206	302	309
Interest expense, net	101	108	110
Other income:			
Allowance for equity funds used during construction	13	6	5
Miscellaneous income, net	7	4	1
Other income, net	20	10	6
Income before income taxes	125	204	205
Income tax expense	21	64	58
Net income	104	140	147
Less: net loss attributable to noncontrolling interests	(1)	(1)	—
Net income attributable to Portland General Electric Company	$ 105	$ 141	$ 147
Weighted-average shares outstanding (in thousands):			
Basic	76,821	75,498	75,333
Diluted	77,388	75,647	75,350
Earnings per share:			
Basic	$ 1.36	$ 1.87	$ 1.95
Diluted	$ 1.35	$ 1.87	$ 1.95

See accompanying notes to consolidated financial statements.

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

	Years Ended December 31,		
	2013	2012	2011
Net income	$ 104	$ 140	$ 147
Other comprehensive income (loss)—Change in compensation retirement benefits liability and amortization, net of taxes of ($1) in 2013 and $1 in 2011	1	—	(1)
Comprehensive income	105	140	146
Less: comprehensive loss attributable to the noncontrolling interests	(1)	(1)	—
Comprehensive income attributable to Portland General Electric Company	$ 106	$ 141	$ 146

See accompanying notes to consolidated financial statements.

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

	As of December 31, 2013	As of December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 107	$ 12
Accounts receivable, net	146	152
Unbilled revenues	104	97
Inventories, at average cost:		
Materials and supplies	41	38
Fuel	24	40
Margin deposits	9	46
Regulatory assets—current	66	144
Other current assets	94	93
Total current assets	591	622
Electric utility plant:		
Production	2,968	2,899
Transmission	417	412
Distribution	2,943	2,816
General	381	327
Intangible	386	357
Construction work-in-progress	508	140
Total electric utility plant	7,603	6,951
Accumulated depreciation and amortization	(2,723)	(2,559)
Electric utility plant, net	4,880	4,392
Regulatory assets—noncurrent	464	524
Nuclear decommissioning trust	82	38
Non-qualified benefit plan trust	35	32
Other noncurrent assets	49	62
Total assets	$ 6,101	$ 5,670

See accompanying notes to consolidated financial statements.

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

	As of December 31,	
	2013	**2012**
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 173	$ 98
Liabilities from price risk management activities—current	49	127
Short-term debt	—	17
Current portion of long-term debt	—	100
Accrued expenses and other current liabilities	171	179
Total current liabilities	393	521
Long-term debt, net of current portion	1,916	1,536
Regulatory liabilities—noncurrent	865	765
Deferred income taxes	586	588
Unfunded status of pension and postretirement plans	154	247
Liabilities from price risk management activities—noncurrent	141	73
Non-qualified benefit plan liabilities	101	102
Asset retirement obligations	100	94
Other noncurrent liabilities	25	14
Total liabilities	4,281	3,940
Commitments and contingencies (see notes)		
Equity:		
Portland General Electric Company shareholders' equity:		
Preferred stock, no par value, 30,000,000 shares authorized; none issued and outstanding	—	—
Common stock, no par value, 160,000,000 shares authorized; 78,085,559 and 75,556,272 shares issued and outstanding as of December 31, 2013 and 2012, respectively	911	841
Accumulated other comprehensive loss	(5)	(6)
Retained earnings	913	893
Total Portland General Electric Company shareholders' equity	1,819	1,728
Noncontrolling interests' equity	1	2
Total equity	1,820	1,730
Total liabilities and equity	$ 6,101	$ 5,670

See accompanying notes to consolidated financial statements.

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

	Portland General Electric Company Shareholders' Equity				
	Common Stock		Accumulated Other Comprehensive Loss	Retained Earnings	Noncontrolling Interests' Equity
	Shares	Amount			
Balance as of December 31, 2010	75,316,419	$ 831	$ (5)	$ 766	$ 7
Shares issued pursuant to equity-based plans	46,537	1	—	—	—
Noncontrolling interests' capital distributions	—	—	—	—	(4)
Stock-based compensation	—	4	—	—	—
Dividends declared ($1.055 per share)	—	—	—	(80)	—
Net income	—	—	—	147	—
Other comprehensive loss	—	—	(1)	—	—
Balance as of December 31, 2011	75,362,956	836	(6)	833	3
Shares issued pursuant to equity-based plans	193,316	1	—	—	—
Stock-based compensation	—	4	—	—	—
Dividends declared ($1.075 per share)	—	—	—	(81)	—
Net income (loss)	—	—	—	141	(1)
Balance as of December 31, 2012	75,556,272	841	(6)	893	2
Issuances of common stock, net of issuance costs of $3	2,365,000	67	—	—	—
Shares issued pursuant to equity-based plans	164,287	1	—	—	—
Stock-based compensation	—	2	—	—	—
Dividends declared ($1.095 per share)	—	—	—	(85)	—
Net income (loss)	—	—	—	105	(1)
Other comprehensive income	—	—	1	—	—
Balance as of December 31, 2013	78,085,559	$ 911	$ (5)	$ 913	$ 1

See accompanying notes to consolidated financial statements.

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

	Years Ended December 31,		
	2013	**2012**	**2011**
Cash flows from operating activities:			
Net income	$ 104	$ 140	$ 147
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	248	248	227
(Decrease) increase in net liabilities from price risk management activities	(18)	(175)	9
Regulatory deferrals—price risk management activities	18	172	(6)
Cascade Crossing transmission project	52	—	—
Deferred income taxes	11	47	56
Renewable adjustment clause deferrals	—	1	22
Pension and other postretirement benefits	37	27	15
Regulatory deferral of settled derivative instruments	7	(9)	12
Power cost deferrals, net of amortization	(6)	(4)	10
Allowance for equity funds used during construction	(13)	(6)	(5)
Decoupling mechanism deferrals, net of amortization	(6)	2	3
Unrealized losses on non-qualified benefit plan trust assets	3	3	—
Other non-cash income and expenses, net	18	16	16
Changes in working capital:			
Increase in receivables and unbilled revenues	—	(4)	(15)
Decrease in margin deposits	37	34	3
Income tax refund received	—	8	9
Increase in payables and accrued liabilities	14	1	5
Other working capital items, net	17	1	(7)
Proceeds received from Trojan spent fuel legal settlement	44	—	—
Contribution to non-qualified employee benefit trust	(6)	—	—
Contribution to voluntary employees' benefit association trust	(3)	(2)	(16)
Contribution to pension plan	—	—	(26)
Other, net	(14)	(6)	(6)
Net cash provided by operating activities	544	494	453
Cash flows from investing activities:			
Capital expenditures	(656)	(303)	(300)
Purchases of nuclear decommissioning trust securities	(26)	(26)	(50)
Sales of nuclear decommissioning trust securities	25	23	46
Contribution to nuclear decommissioning trust	(44)	—	—
Proceeds received from insurance recovery	6	—	—
Proceeds from sale of solar power facility	—	10	—
Other, net	3	2	5
Net cash used in investing activities	(692)	(294)	(299)

See accompanying notes to consolidated financial statements.

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

	Years Ended December 31,		
	2013	2012	2011
Cash flows from financing activities:			
Proceeds from issuance of long-term debt	$ 380	$ —	$ —
Payments on long-term debt	(100)	(100)	(73)
Proceeds from issuances of common stock, net of issuance costs	67	—	—
Borrowings on short-term debt	35	—	—
Payments on short-term debt	(35)	—	—
(Maturities) issuances of commercial paper, net	(17)	(13)	11
Dividends paid	(84)	(81)	(79)
Premium paid on repayment of long-term debt	—	—	(7)
Debt issuance costs	(3)	—	—
Noncontrolling interests' capital distributions	—	—	(4)
Net cash provided by (used in) financing activities	243	(194)	(152)
Increase in cash and cash equivalents	95	6	2
Cash and cash equivalents, beginning of year	12	6	4
Cash and cash equivalents, end of year	$ 107	$ 12	$ 6
Supplemental disclosures of cash flow information:			
Cash paid for interest, net of amounts capitalized	$ 90	$ 97	$ 103
Cash paid for income taxes	10	13	3
Non-cash investing and financing activities:			
Accrued capital additions	84	19	19
Accrued dividends payable	22	21	21
Preliminary engineering transferred to Construction work in progress from Other noncurrent assets	9	—	7

See accompanying notes to consolidated financial statements.

NOTE 1: BASIS OF PRESENTATION

Nature of Operations

Portland General Electric Company (PGE or the Company) is a single, vertically integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon. The Company also sells electricity and natural gas in the wholesale market to utilities, brokers, and power marketers. PGE operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. PGE's corporate headquarters is located in Portland, Oregon and its service area is located entirely within Oregon. PGE's service area includes 52 incorporated cities, of which Portland and Salem are the largest, within a state-approved service area allocation of approximately 4,000 square miles. As of December 31, 2013, PGE served 836,070 retail customers with a service area population of approximately 1.7 million, comprising approximately 44% of the state's population.

As of December 31, 2013, PGE had 2,596 employees, with 795 employees covered under two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 760 and 35 employees and expire in February 2015 and August 2014, respectively.

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

Consolidation Principles

The consolidated financial statements include the accounts of PGE and its wholly-owned subsidiaries and those variable interest entities (VIEs) where PGE has determined it is the primary beneficiary. The Company's ownership share of direct expenses and costs related to jointly-owned generating plants are also included in its consolidated financial statements. Intercompany balances and transactions have been eliminated.

For entities that are determined to meet the definition of a VIE and where the Company has determined it is the primary beneficiary, the VIE is consolidated and a noncontrolling interest is recognized for any third party interests. This has resulted in the Company consolidating entities in which it has less than a 50% equity interest. For further information, see Note 16, Variable Interest Entities.

Use of Estimates

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

Customer Billing Matter

In May 2013, PGE discovered that it had over-billed an industrial customer during a period of several years as a result of a meter configuration error. An analysis of the data determined that the Company's revenues were overstated by approximately

$3 million in 2012 and in 2011, $2 million in 2010, and $1 million in 2009. PGE believes the customer billing error is not material to any annual reporting period. The Company corrected this matter in the second quarter of 2013 as an out of period adjustment, and recorded, as a reduction to Revenues, net, a refund to the customer in the amount of $9 million.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash and Cash Equivalents

Highly liquid investments with maturities of three months or less at the date of acquisition are classified as cash equivalents, of which PGE had $104 million as of December 31, 2013 and none as of December 31, 2012.

Accounts Receivable

Accounts receivable are recorded at invoiced amounts based on prices that are subject to federal (FERC) and state (OPUC) regulations. Balances do not bear interest; however, late fees are assessed beginning 16 business days after the invoice due date. Accounts that are inactivated due to nonpayment are charged-off in the period in which the receivable is deemed uncollectible, but no sooner than 45 business days after the due date of the final invoice.

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

Provisions for uncollectible accounts receivable related to wholesale sales are charged to Purchased power and fuel expense and are recorded periodically based on a review of counterparty non-performance risk and contractual right of offset when applicable. There have been no material write-offs of accounts receivable related to wholesale sales in 2013, 2012 and 2011.

Price Risk Management

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

Price risk management activities are utilized as economic hedges to protect against variability in expected future cash flows due to associated price risk and to manage exposure to volatility in net power costs for the Company's retail customers.

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

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

Pursuant to transactions entered into in connection with PGE's price risk management activities, the Company may be required to provide collateral with certain counterparties. The collateral requirements are based on the contract terms and commodity prices and can vary period to period. Cash deposits provided as collateral are classified as Margin deposits in the consolidated balance sheets and were $9 million and $46 million as of December 31, 2013 and 2012, respectively. Letters of credit provided as collateral are not recorded on the Company's consolidated balance sheet and were $29 million and $45 million as of December 31, 2013 and 2012, respectively.

Inventories

PGE's inventories, which are recorded at average cost, consist primarily of materials and supplies for use in operations, maintenance and capital activities and fuel for use in generating plants. Fuel inventories include natural gas, oil, and coal. Periodically, the Company assesses the realizability of inventory for purposes of determining that inventory is recorded at the lower of average cost or market.

Electric Utility Plant

Capitalization Policy

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

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

During the year ended December 31, 2013, PGE charged $52 million of costs previously included in CWIP related to the Cascade Crossing Transmission Project (Cascade Crossing), which was originally proposed as a 215-mile, 500 kV transmission project between Boardman, Oregon and Salem, Oregon. Based on an updated forecast of demand and future transmission capacity in the region, PGE determined in the second quarter of 2013 that the original projections of transmission capacity limitations contemplated in the Company's 2009 Integrated Resource Plan, as acknowledged by the OPUC, were not likely to fully materialize. As a result, PGE and Bonneville Power Administration (BPA) worked toward refining the scope of the project and executed a non-binding memorandum of understanding (MOU) in May 2013. In connection with the MOU, the parties explored a new option under which BPA could provide PGE with ownership of approximately 1,500 MW of transmission capacity rights. As a result of the changed conditions reflected in the MOU, PGE also suspended permitting and development of Cascade Crossing and charged the capitalized costs related to Cascade Crossing to expense in the second quarter of 2013. In October 2013, the parties determined that they would not be able to reach an agreement on the financial terms for the proposed ownership of transmission capacity rights and, therefore, agreed to discontinue discussions on this option. The Company has determined that, under current conditions, the best option for meeting its transmission needs is to continue to acquire transmission service offered under BPA's Open Access Transmission Tariff. PGE has determined that it will not seek recovery of these costs.

PGE records AFDC, which is intended to represent the Company's cost of funds used for construction purposes and is based on the rate granted in the latest general rate case for equity funds and the cost of actual borrowings for debt funds. AFDC is capitalized as part of the cost of plant and credited to the consolidated statements of income. The average rate used by PGE was 7.5% in 2013 and in 2012 and 7.8% in 2011. AFDC from borrowed funds was $7 million in 2013, $4 million in 2012, and $3 million in 2011 and is reflected as a reduction to Interest expense. AFDC from equity funds was $13 million in 2013, $6 million in 2012, and $5 million in 2011 and is included in Other income, net.

Costs disallowed for recovery in customer prices, if any, are charged to expense at the time such disallowance is probable.

Depreciation and Amortization

Depreciation is computed using the straight-line method, based upon original cost, and includes an estimate for cost of removal and expected salvage. Depreciation expense as a percent of the related average depreciable plant in service was 3.7% in 2013, 3.8% in 2012, and 3.7% in 2011. Estimated asset retirement removal costs included in depreciation expense were $55 million in 2013 and 2012, and $49 million in 2011.

Periodic studies are conducted to update depreciation parameters (i.e. retirement dispersion patterns, average service lives, and net salvage rates), including estimates of asset retirement obligations (AROs) and asset retirement removal costs. The studies are conducted at a minimum of every five years and are filed with the OPUC for approval and inclusion in a future rate proceeding. The most recent depreciation study was completed for 2009, with an order received from the OPUC in September 2010 authorizing new depreciation rates effective January 1, 2011. During 2013, a depreciation study was completed, which has been incorporated into the Company's general rate case filed with the OPUC on February 13, 2014, with new prices expected to become effective January 1, 2015.

Thermal generation plants are depreciated using a life-span methodology which ensures that plant investment is recovered by the estimated retirement dates, which range from 2020 to 2050. Depreciation is provided on the Company's other classes of plant in service over their estimated average service lives, which are as follows (in years):

Generation, excluding thermal:	
Hydro	87
Wind	27
Transmission	53
Distribution	40
General	13

The original cost of depreciable property units, net of any related salvage value, is charged to accumulated depreciation when property is retired and removed from service. Cost of removal expenditures are recorded against AROs or to accumulated asset retirement removal costs, included in Regulatory liabilities, for assets without AROs.

Intangible plant consists primarily of computer software development costs, which are amortized over either five or ten years, and hydro licensing costs, which are amortized over the applicable license term, which range from 30 to 50 years. Accumulated amortization was $170 million and $151 million as of December 31, 2013 and 2012, respectively, with amortization expense of $22 million in 2013 and in 2012, and $19 million in 2011. Future estimated amortization expense as of December 31, 2013 is as follows: $23 million in 2014; $22 million in 2015; $19 million in 2016; $16 million in 2017; and $14 million in 2018.

Marketable Securities

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

Regulatory Accounting

Regulatory Assets and Liabilities

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

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

For additional information concerning the Company's regulatory assets and liabilities, see Note 6, Regulatory Assets and Liabilities.

Power Cost Adjustment Mechanism

PGE is subject to a power cost adjustment mechanism (PCAM) as approved by the OPUC. Pursuant to the PCAM, the Company can adjust future customer prices to reflect a portion of the difference between each year's forecasted net variable power costs (NVPC) included in customer prices (baseline NVPC) and actual NVPC. PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and baseline NVPC by application of an asymmetrical "deadband," which ranges from $15 million below to $30 million above baseline NVPC. NVPC consists of (i) the cost of power purchased and fuel used to generate electricity to meet PGE's retail load requirements, as well as the cost of settled electric and natural gas financial contracts, all of which is classified as Purchased power and fuel in the Company's consolidated statements of income; and is net of (ii) wholesale sales, which are classified as Revenues, net in the consolidated statements of income.

To the extent actual NVPC, subject to certain adjustments, is outside the deadband range, the PCAM provides for 90% of the variance to be collected from or refunded to customers, subject to a regulated earnings test. Pursuant to the regulated earnings test, a refund will occur only to the extent that it results in PGE's actual regulated return on equity (ROE) for that year being no less than 1% above the Company's latest authorized ROE, while a collection will occur only to the extent that it results in PGE's actual regulated ROE for that year being no greater than 1% below the Company's authorized ROE. PGE's authorized ROE was 10% for 2013, 2012 and 2011.

Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Revenues in the Company's consolidated statements of income, while any estimated collection from customers is recorded as a reduction in Purchased power and fuel expense. A final determination of any customer refund or collection is made in the following year by the OPUC through a public filing and review.

For 2013, actual NVPC was above baseline NVPC by $11 million, which is within the established deadband range. Accordingly, no estimated collection from customers was recorded as of December 31, 2013. A final determination regarding the 2013 PCAM results will be made by the OPUC through a public filing and review in 2014.

For 2012, actual NVPC was below baseline NVPC by $17 million, and exceeded the lower deadband threshold of $15 million. However, based on results of the regulated earnings test, no estimated refund to customers was recorded as of December 31, 2012. A final determination regarding the 2012 PCAM results was made by the OPUC through a public filing and review in 2013, which confirmed no refund to customers pursuant to the PCAM for 2012.

For 2011, actual NVPC was below baseline NVPC by $34 million, and exceeded the lower deadband threshold of $15 million. PGE recorded an estimated refund to customers of $10 million as of December 31, 2011, reduced from the $17 million potential refund to customers as a result of the regulated earnings test. A final determination regarding the 2011 PCAM results was made by the OPUC through a public filing and review in 2012, which, based upon the application of an updated regulated earnings test, resulted in a revised refund to customers of $6 million to be returned to customers over a one-year period beginning January 1, 2013.

Asset Retirement Obligations

Legal obligations related to the future retirement of tangible long-lived assets are classified as AROs on PGE's consolidated balance sheet. An ARO is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. Due to the long lead time involved until decommissioning activities occur, the Company uses present value techniques because quoted market prices and a market-risk premium are not available. The present value of estimated future dismantlement and restoration costs is capitalized and included in Electric utility plant, net on the consolidated balance sheets with a corresponding offset to ARO. Such estimates are revised periodically, with actual expenditures charged to the ARO as incurred.

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

The difference between the timing of the recognition of the AROs' depreciation and accretion expenses and the amount included in customers' prices is recorded as a regulatory asset or liability in the Company's consolidated balance sheets. PGE had a regulatory liability related to AROs in the amount of $39 million as of December 31, 2013 and 2012. See Note 6, Regulatory Assets and Liabilities.

Contingencies

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

A loss contingency will also be disclosed when it is reasonably possible that an asset has been impaired or a liability incurred if the estimate or range of potential loss is material. If a probable or reasonably possible loss cannot be reasonably estimated, disclosure of the loss contingency includes a statement to that effect and the reasons.

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

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

Accumulated Other Comprehensive Loss

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

Revenue Recognition

Revenues are recognized as electricity is delivered to customers and include amounts for any services provided. The prices charged to customers are subject to federal (FERC), and state (OPUC) regulation. Franchise taxes, which are collected from customers and remitted to taxing authorities, are recorded on a gross basis in PGE's consolidated statements of income. Amounts collected from customers are included in Revenues, net and amounts due to taxing authorities are included in Taxes other than income taxes and totaled $41 million in 2013, $42 million in 2012, and $41 million in 2011.

Retail revenue is billed monthly based on meter readings taken throughout the month. Unbilled revenue represents the revenue earned from the last meter read date through the last day of the month, which has not been billed as of the last day of the month. Unbilled revenue is calculated based on each month's actual net retail system load, the number of days from the last meter read date through the last day of the month, and current retail customer prices.

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

Stock-Based Compensation

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

Income Taxes

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

As a rate-regulated enterprise, changes in deferred tax assets and liabilities that are related to certain property are required to be passed on to customers through future prices and are charged or credited directly to a regulatory asset or regulatory liability. These amounts were recognized as net regulatory assets of $76 million and $80 million as of December 31, 2013 and 2012, respectively, and will be included in prices when the temporary differences reverse.

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

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

Recent Accounting Pronouncement

Accounting Standards Update (ASU) 2011-11, *Balance Sheet (Topic 210) - Disclosures about Offsetting Assets and Liabilities* (ASU 2011-11), requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. In addition, ASU 2013-01, *Balance Sheet (Topic 210) - Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities* (ASU 2013-01), was issued in January 2013 and clarifies that the scope of ASU 2011-11 applies to financial instruments accounted for in accordance with Topic 815, *Derivatives and Hedging*. Both ASUs were effective January 1, 2013 for the Company, and require retrospective application. PGE adopted the amendments contained in ASU 2011-11 and ASU 2013-01 on January 1, 2013, which did not have an impact on the Company's consolidated financial position, consolidated results of operations, or consolidated cash flows. See Note 5, Price Risk Management, for the additional disclosures made pursuant to the adoption of these ASUs.

NOTE 3: BALANCE SHEET COMPONENTS

Accounts Receivable, Net

Accounts receivable is net of an allowance for uncollectible accounts of $6 million and $5 million as of December 31, 2013 and 2012, respectively. The following is the activity in the allowance for uncollectible accounts (in millions):

	Years Ended December 31,		
	2013	2012	2011
Balance as of beginning of year	$ 5	$ 6	$ 5
Increase in provision	6	6	11
Amounts written off, less recoveries	(5)	(7)	(10)
Balance as of end of year	$ 6	$ 5	$ 6

Trust Accounts

PGE maintains two trust accounts as follows:

Nuclear decommissioning trust—Reflects assets held in trust to cover general decommissioning costs and operation of the Independent Spent Fuel Storage Installation (ISFSI) and represent amounts collected from customers less qualified expenditures plus any realized and unrealized gains and losses on the investments held therein. During 2013, the Company received $44 million from the settlement of a legal matter concerning costs associated with the operation of the ISFSI. Those funds were deposited into the Nuclear decommissioning trust. For additional information concerning the legal matter, see Note 7, Asset Retirement Obligations.

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

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

	Nuclear Decommissioning Trust		Non-Qualified Benefit Plan Trust	
	2013	2012	2013	2012
Cash equivalents	$ 59	$ 15	$ —	$ 2
Marketable securities, at fair value:				
Equity securities	—	—	8	5
Debt securities	23	23	1	2
Insurance contracts, at cash surrender value	—	—	26	23
	$ 82	$ 38	$ 35	$ 32

For information concerning the fair value measurement of those assets recorded at fair value held in the trusts, see Note 4, Fair Value of Financial Instruments.

Other Current Assets and Accrued Expenses and Other Current Liabilities

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

	As of December 31,	
	2013	2012
Other current assets:		
Current deferred income tax asset	$ 42	$ 51
Prepaid expenses	38	37
Assets from price risk management activities	13	4
Other	1	1
	$ 94	$ 93
Accrued expenses and other current liabilities:		
Accrued employee compensation and benefits	$ 46	$ 46
Accrued interest payable	23	23
Dividends payable	22	21
Accrued taxes payable	21	21
Regulatory liabilities—current	1	12
Other	58	56
	$ 171	$ 179

NOTE 4: FAIR VALUE OF FINANCIAL INSTRUMENTS

PGE determines the fair value of financial instruments, both assets and liabilities recognized and not recognized in the Company's consolidated balance sheets, for which it is practicable to estimate fair value as of December 31, 2013 and 2012, and then classifies these financial assets and liabilities based on a fair value hierarchy. The fair value hierarchy is used to prioritize the inputs to the valuation techniques used to measure fair value. These three broad levels and application to the Company are discussed below.

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

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

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

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy.

PGE recognizes transfers between levels in the fair value hierarchy as of the end of the reporting period for all of its financial instruments. Changes to market liquidity conditions, the availability of observable inputs, or changes in the economic structure of a security marketplace may require transfer of the securities between levels. There were no significant transfers between levels during the years ended December 31, 2013 and 2012, except those transfers from Level 3 to Level 2 presented in this note.

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

	As of December 31, 2013			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets:				
Nuclear decommissioning trust [1]:				
Money market funds	$ —	$ 59	$ —	$ 59
Debt securities:				
Domestic government	6	8	—	14
Corporate credit	—	9	—	9
Non-qualified benefit plan trust [2]:				
Equity securities:				
Domestic	4	3	—	7
International	1	—	—	1
Debt securities - domestic government	1	—	—	1
Assets from price risk management activities [1] [3]:				
Electricity	—	9	1	10
Natural gas	—	4	—	4
	$ 12	$ 92	$ 1	$ 105
Liabilities - Liabilities from price risk management activities [1] [3]:				
Electricity	$ —	$ 10	$ 117	$ 127
Natural gas	—	40	23	63
	$ —	$ 50	$ 140	$ 190

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in regulatory assets or regulatory liabilities as appropriate.
(2) Excludes insurance policies of $26 million, which are recorded at cash surrender value.
(3) For further information, see Note 5, Price Risk Management.

	As of December 31, 2012			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trust [1]:				
Money market funds	$ —	$ 15	$ —	$ 15
Debt securities:				
Domestic government	7	8	—	15
Corporate credit	—	8	—	8
Non-qualified benefit plan trust [2]:				
Money market funds	—	2	—	2
Equity securities:				
Domestic	2	2	—	4
International	1	—	—	1
Debt securities - domestic government	2	—	—	2
Assets from price risk management activities [1] [3]:				
Electricity	—	1	—	1
Natural gas	—	3	2	5
	$ 12	$ 39	$ 2	$ 53
Liabilities - Liabilities from price risk management activities [1] [3]:				
Electricity	$ —	$ 72	$ 10	$ 82
Natural gas	—	110	8	118
	$ —	$ 182	$ 18	$ 200

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in regulatory assets or regulatory liabilities as appropriate.
(2) Excludes insurance policies of $23 million, which are recorded at cash surrender value.
(3) For further information, see Note 5, Price Risk Management.

Trust assets held in the Nuclear decommissioning and Non-qualified benefit plan trusts are recorded at fair value in PGE's consolidated balance sheets and invested in securities that are exposed to interest rate, credit and market volatility risks. These assets are classified within Level 1, 2 or 3 based on the following factors:

Money market funds—PGE invests in money market funds that seek to maintain a stable net asset value. These funds invest in high-quality, short-term, diversified money market instruments, short-term treasury bills, federal agency securities, certificates of deposits, and commercial paper. Money market funds are classified as Level 2 in the fair value hierarchy as the securities are traded in active markets of similar securities but are not directly valued using quoted market prices.

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

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

Equity securities—Equity mutual fund and common stock securities are primarily classified as Level 1 in the fair value hierarchy due to the availability of quoted prices for identical assets in an active market as of the reporting date. Principal markets for equity prices include published exchanges such as NASDAQ and the New York Stock Exchange (NYSE). Certain mutual fund assets included in commingled trusts or separately managed accounts are classified as Level 2 in the fair value hierarchy as pricing inputs are directly or indirectly observable in the marketplace.

Assets and liabilities from price risk management activities are recorded at fair value in PGE's consolidated balance sheets and consist of derivative instruments entered into by the Company to manage its exposure to commodity price risk and foreign currency exchange rate risk, and reduce volatility in net power costs for the Company's retail customers. For additional information regarding these assets and liabilities, see Note 5, Price Risk Management.

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

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

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

Commodity Contracts	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Price per Unit Low	Price per Unit High	Price per Unit Weighted Average
	(in millions)						
As of December 31, 2013:							
Electricity physical forward	$ —	$ 103	Discounted cash flow	Electricity forward price (per MWh)	$ 9.63	$77.95	$ 40.18
Natural gas financial swaps	—	23	Discounted cash flow	Natural gas forward price (per Dth)	3.16	4.49	3.71
Electricity financial futures	1	14	Discounted cash flow	Electricity forward price (per MWh)	9.63	46.07	33.01
	$ 1	$ 140					
As of December 31, 2012:							
Natural gas financial swaps	$ 2	$ 8	Discounted cash flow	Natural gas forward price (per Dth)	$ 3.67	$ 5.21	$ 4.28
Electricity financial swaps	—	10	Discounted cash flow	Electricity forward price (per MWh)	7.12	51.72	41.14
	$ 2	$ 18					

The significant unobservable inputs used in the Company's fair value measurement of price risk management assets and liabilities are long-term forward prices for commodity derivatives. For shorter term contracts, the Company uses internally-developed price curves that employ the mid-point of the market's bid-ask spread derived using observed transactions in active markets, as well as historical experience as a participant in those markets. These internally-developed price curves are validated against nonbinding quotes from brokers with whom the Company transacts. For certain longer term contracts, observable, liquid market transactions are not available for the duration of the delivery period. In such circumstances, the Company uses internally-developed price curves, which utilize observable data and regression techniques to derive future prices. In addition, changes in the fair value measurement of price risk management assets and liabilities are analyzed and reviewed on a monthly basis by the Company. This process includes analytical review of changes in commodity prices as well as procedures to analyze and identify the reasons for the changes over specific reporting periods.

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

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

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

	Years Ended December 31, 2013	Years Ended December 31, 2012
Net liabilities from price risk management activities as of beginning of year	$ 16	$ 79
Net realized and unrealized losses [1]	134	15
Purchases	—	(1)
Issuances	—	(1)
Settlements	(1)	—
Net transfers out of Level 3 to Level 2	(10)	(76)
Net liabilities from price risk management activities as of end of year	$ 139	$ 16
Level 3 net unrealized losses that have been fully offset by the effect of regulatory accounting	$ 133	$ 14

(1) Includes realized losses, net of $1 million in 2013 and in 2012.

Transfers into Level 3 occur when significant inputs used to value the Company's derivative instruments become less observable, such as a delivery location becoming significantly less liquid. During the years ended December 31, 2013 and 2012, there were no transfers into Level 3 from Level 2. Transfers out of Level 3 occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery term of a transaction becomes shorter. PGE records transfers in and transfers out of Level 3 at the end of the reporting period for all of its financial instruments. Transfers from Level 2 to Level 1 for the Company's price risk management assets and liabilities do not occur as quoted prices are not available for identical instruments. As such, the Company's assets and liabilities from price risk management activities mature and settle as Level 2 fair value measurements.

Long-term debt is recorded at amortized cost in PGE's consolidated balance sheets. The fair value of long-term debt is classified as a Level 2 fair value measurement and is estimated based on the quoted market prices for the same or similar issues or on the current rates offered to PGE for debt of similar remaining maturities. As of December 31, 2013, the estimated aggregate fair value of PGE's long-term debt was $2,074 million, compared to its $1,916 million carrying amount. As of December 31, 2012, the estimated aggregate fair value of PGE's long-term debt was $1,949 million, compared to its $1,636 million carrying amount.

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

NOTE 5: PRICE RISK MANAGEMENT

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

PGE utilizes derivative instruments in its wholesale electric utility activities to manage its exposure to commodity price risk and foreign exchange rate risk in order to manage volatility in net power costs for its retail customers. These derivative instruments may include forward, futures, swap, and option contracts for electricity, natural gas, oil and foreign currency, which are recorded at fair value on the consolidated balance sheet, with changes in fair value recorded in the statement of income. In accordance with ratemaking and cost recovery processes authorized by the OPUC, PGE recognizes a regulatory asset or liability to defer the gains and losses from derivative activity until settlement of the associated derivative instrument. PGE may designate certain derivative instruments as cash flow hedges or may use derivative instruments as economic hedges. PGE does not engage in trading activities for non-retail purposes.

PGE's Assets and Liabilities from price risk management activities consist of the following (in millions):

	As of December 31,	
	2013	2012
Current assets:		
Commodity contracts:		
Electricity	$ 9	$ 1
Natural gas	4	3
Total current derivative assets	13 (1)	4 (1)
Noncurrent assets:		
Commodity contracts:		
Electricity	1	—
Natural gas	—	2
Total noncurrent derivative assets	1	2
Total derivative assets not designated as hedging instruments	$ 14 (2)	$ 6 (2)
Total derivative assets	$ 14	$ 6
Current liabilities:		
Commodity contracts:		
Electricity	$ 20	$ 44
Natural gas	29	83
Total current derivative liabilities	49	127
Noncurrent liabilities:		
Commodity contracts:		
Electricity	107	38
Natural gas	34	35
Total noncurrent derivative liabilities	141	73
Total derivative liabilities not designated as hedging instruments	$ 190	$ 200
Total derivative liabilities	$ 190	$ 200

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

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

	As of December 31,					
	2013			2012		
Commodity contracts:						
Electricity		14	MWh		11	MWh
Natural gas		106	Dth		86	Dth
Foreign currency exchange	$	7	Canadian	$	7	Canadian

PGE has elected to report gross on the consolidated balance sheets the positive and negative exposures resulting from derivative instruments pursuant to agreements that meet the definition of a master netting arrangement. In the case of default on, or termination of, any contract under the master netting arrangements, these agreements provide for the net settlement of all related contractual obligations with a counterparty through a single payment. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, receivables and payables arising from settled positions, and other forms of non-cash collateral, such as letters of credit, which are excluded from the offsetting table below.

Information related to price risk management liabilities subject to master netting agreements is as follows (in millions):

	Gross Amounts Recognized	Gross Amounts Offset	Net Amounts Presented	Gross Amounts Not Offset in Condensed Consolidated Balance Sheets		Net Amount
				Derivatives	Cash Collateral(1)	
As of December 31, 2013:						
Liabilities:						
Commodity contracts:						
Electricity(2)	$ 91	$ —	$ 91	$ (91)	$ —	$ —
Natural gas(2)	1	—	1	(1)	—	—
	$ 92	$ —	$ 92	$ (92)	$ —	$ —
As of December 31, 2012:						
Liabilities:						
Commodity contracts:						
Electricity(2)	$ 20	$ —	$ 20	$ (20)	$ —	$ —
Natural gas(2)	7	—	7	(7)	—	—
	$ 27	$ —	$ 27	$ (27)	$ —	$ —

(1) As of December 31, 2013 and 2012, the Company had collateral posted of $7 million and $18 million, respectively, which consists entirely of letters of credit.
(2) Included in Liabilities from price risk management activities—current and Liabilities from price risk management activities—noncurrent.

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

	Years Ended December 31,		
	2013	2012	2011
Commodity contracts:			
Electricity	$ 78	$ 56	$ 117
Natural Gas	28	19	98
Foreign currency exchange	1	—	—

Net unrealized losses and certain net realized losses presented in the table above are offset within the statement of income by the effects of regulatory accounting. Of the net loss recognized in net income for the years ended December 31, 2013, 2012, and 2011, $120 million, $42 million, and $192 million, respectively, have been offset.

Assuming no changes in market prices and interest rates, the following table indicates the year in which the net unrealized loss recorded as of December 31, 2013 related to PGE's derivative activities would be realized as a result of the settlement of the underlying derivative instrument (in millions):

	2014	2015	2016	2017	2018	Thereafter	Total
Commodity contracts:							
Electricity	$ 11	$ 26	$ 12	$ 5	$ 5	$ 58	$ 117
Natural gas	25	10	14	10	—	—	59
Net unrealized loss	$ 36	$ 36	$ 26	$ 15	$ 5	$ 58	$ 176

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

The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position as of December 31, 2013 was $186 million, for which the Company had posted $30 million in collateral, consisting primarily of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at December 31, 2013, the cash requirement to either post as collateral or settle the instruments immediately would have been $181 million. As of December 31, 2013, PGE had posted an additional $9 million in cash collateral for derivative instruments with no credit-risk-related contingent features, which is classified as Margin deposits on the Company's consolidated balance sheet.

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

	As of December 31,	
	2013	2012
Assets from price risk management activities:		
Counterparty A	53%	—%
Counterparty B	5	21
Counterparty C	5	11
Counterparty D	4	13
Counterparty E	—	10
	67%	55%
Liabilities from price risk management activities:		
Counterparty F	43%	—%
Counterparty G	11	—
Counterparty H	6	24
Counterparty I	5	10
Counterparty A	2	14
	67%	48%

For additional information concerning the determination of fair value for the Company's Assets and Liabilities from price risk management activities, see Note 4, Fair Value of Financial Instruments.

NOTE 6: REGULATORY ASSETS AND LIABILITIES

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

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

	Weighted Average Remaining Life [1]	As of December 31,			
		2013		2012	
		Current	Noncurrent	Current	Noncurrent
Regulatory assets:					
Price risk management [2]	6 years	$ 36	$ 140	$ 123	$ 71
Pension and other postretirement plans [2]	[3]	—	194	—	321
Deferred income taxes [2]	[4]	—	76	—	80
Deferred broker settlements [2]	1 year	12	1	20	1
Debt issuance costs [2]	8 years	—	17	—	22
Deferred capital projects	2 years	16	18	—	16
Other [5]	Various	2	18	1	13
Total regulatory assets		$ 66	$ 464	$ 144	$ 524
Regulatory liabilities:					
Asset retirement removal costs [7]	[4]	$ —	$ 747	$ —	$ 692
Trojan decommissioning activities	[6]	—	41	—	—
Asset retirement obligations [7]	[4]	—	39	—	39
Other	Various	1	38	12	34
Total regulatory liabilities		$ 1 [8]	$ 865	$ 12 [8]	$ 765

(1) As of December 31, 2013.
(2) Does not include a return on investment.
(3) Recovery expected over the average service life of employees. For additional information, see Note 2, Summary of Significant Accounting Policies.
(4) Recovery expected over the estimated lives of the assets.
(5) Of the total other unamortized regulatory asset balances, a return is recorded on $16 million and $15 million as of December 31, 2013 and 2012, respectively.
(6) Refund period not yet determined.
(7) Included in rate base for ratemaking purposes.
(8) Included in Accrued expenses and other current liabilities on the consolidated balance sheets.

As of December 31, 2013, PGE had regulatory assets of $59 million earning a return on investment at the following rates: (i) $34 million at PGE's cost of debt of 6.065%; (ii) $15 million earning a return by inclusion in rate base; (iii) $9 million at the approved rate for deferred accounts under amortization, ranging from 1.38% to 2.24%, depending on the year of approval; and (iv) $1 million at PGE's cost of capital of 8.033%.

Price risk management represents the difference between the net unrealized losses recognized on derivative instruments related to price risk management activities and their realization and subsequent recovery in customer prices. For further information regarding assets and liabilities from price risk management activities, see Note 5, Price Risk Management.

Pension and other postretirement plans represents unrecognized components of the benefit plans' funded status, which are recoverable in customer prices when recognized in net periodic benefit cost. For further information, see Note 10, Employee Benefits.

Deferred income taxes represents income tax benefits resulting from property-related timing differences that previously flowed to customers and will be included in customer prices when the temporary differences reverse. For further information, see Note 11, Income Taxes.

Deferred broker settlements consist of transactions that have been financially settled by clearing brokers prior to the contract delivery date. These gains and losses are deferred for future recovery in customer prices during the corresponding contract settlement month.

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

Deferred capital projects represents costs related to four capital projects that were deferred for future accounting treatment pursuant to the Company's 2011 General Rate Case. The recovery of these project costs in future customer prices is subject to a regulated earnings test and approval by the OPUC.

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

Trojan decommissioning activities represent a $44 million settlement for the reimbursement of certain monitoring costs incurred related to spent nuclear fuel at the Company's Trojan nuclear power plant (Trojan). The proceeds will benefit customers in future regulatory proceedings and offset amounts previously collected from customers in relation to Trojan decommissioning activities.

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

NOTE 7: ASSET RETIREMENT OBLIGATIONS

AROs consist of the following (in millions):

	As of December 31,	
	2013	**2012**
Trojan decommissioning activities	$ 41	$ 42
Utility plant	49	39
Non-utility property	10	13
Asset retirement obligations	$ 100	$ 94

Trojan decommissioning activities represents the present value of future decommissioning expenditures for the plant, which ceased operation in 1993. The remaining decommissioning activities primarily consist of the long-term operation and decommissioning of the ISFSI, an interim dry storage facility that is licensed by the Nuclear Regulatory Commission. The ISFSI is to house the spent nuclear fuel at the former plant site until an off-site storage facility is available. Decommissioning of the ISFSI and final site restoration activities will begin once shipment of all the spent fuel to a United States Department of Energy (USDOE) facility is complete, which is not expected prior to 2033.

In 2004, the co-owners of Trojan (PGE, Eugene Water & Electric Board, and PacifiCorp, collectively referred to as Plaintiffs) filed a complaint against the USDOE for failure to accept spent nuclear fuel by January 31, 1998. PGE had contracted with the USDOE for the permanent disposal of spent nuclear fuel in order to allow the final decommissioning of Trojan. The Plaintiffs paid for permanent disposal services during the period of plant operation and have met all other conditions precedent. The Plaintiffs were seeking approximately $112 million in damages incurred through 2009.

A trial before the U.S. Court of Federal Claims concluded in early 2012, and on November 30, 2012, the U.S. Court of Federal Claims issued a judgment awarding certain damages to the Plaintiffs. The judgment did not state the precise amount of the damages award, but directed the parties to consult and propose a final amount for the Plaintiffs' recovery that was based on certain adjustments specified in the court's ruling. In July 2013, the parties reached a settlement wherein the Trojan co-owners were to receive approximately $70 million for the period through 2009. PGE's share, approximately $44 million, was received during the third quarter 2013 and deposited into the Nuclear decommissioning trust. The proceeds received related to this legal matter will flow to the benefit of customers in future regulatory proceedings to offset amounts previously collected from customers in relation to Trojan decommissioning activities. The Trojan ARO is not impacted by the outcome of this case as such recovery is for past decommissioning costs and the ARO reflects only future decommissioning expenditures.

The settlement agreement also provided for a process to submit claims for allowable costs for the period 2010 through 2013. In January 2014, the settlement agreement was extended to cover costs through 2016. The Company will seek recovery of any costs for subsequent periods in future extensions of the agreement.

In October 2013, the Trojan co-owners submitted a claim for $9 million related to 2010 through 2012 costs, with PGE's share approximating $6 million. The Company expects to receive payment for the submitted claim in mid-2014.

Utility plant represents AROs that have been recognized for the Company's thermal and wind generation sites, distribution and transmission assets where disposal is governed by environmental regulation.

During 2011, an updated decommissioning study for PGE's Boardman coal-fired generating plant (Boardman) was completed, which included the assumption that Boardman's coal-fired operations cease in 2020 rather than 2040. As a result of the study, PGE increased its ARO related to Boardman by approximately $20 million, with a corresponding increase in the cost basis of the plant, included in Electric utility plant, net on the consolidated balance sheet. Such transaction is non-cash and is excluded from investing activities in the consolidated statement cash flows for the year ended December 31, 2011. Furthermore, in December 2013, PGE increased the ARO by $4 million related to the acquisition of an additional 15% interest in Boardman.

Non-utility property primarily represents AROs which have been recognized for portions of unregulated properties leased to third parties.

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

	Years Ended December 31,		
	2013	2012	2011
Balance as of beginning of year	$ 94	$ 87	$ 64
Liabilities incurred	4	—	1
Liabilities settled	(4)	(3)	(4)
Accretion expense	6	6	4
Revisions in estimated cash flows	—	4	22
Balance as of end of year	$ 100	$ 94	$ 87

Pursuant to regulation, the amortization of utility plant AROs is included in depreciation expense and in customer prices. Any differences in the timing of recognition of costs for financial reporting and ratemaking purposes are deferred as a regulatory asset or regulatory liability. Recovery of Trojan decommissioning costs is included in PGE's retail prices, currently at approximately $4 million annually, with an equal amount recorded in Depreciation and amortization expense.

PGE maintains a separate trust account, Nuclear decommissioning trust in the consolidated balance sheet, for funds collected from customers through prices to cover the cost of Trojan decommissioning activities. See "*Trust Accounts*" in Note 3, Balance Sheet Components, for additional information on the Nuclear decommissioning trust.

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

NOTE 8: CREDIT FACILITIES

PGE has credit facilities with an aggregate capacity of $700 million as follows:

- A $400 million syndicated unsecured revolving credit facility, which is scheduled to terminate in November 2018; and
- A $300 million syndicated unsecured revolving credit facility, which is scheduled to terminate in December 2017.

Pursuant to the terms of the agreements, both revolving credit facilities may be used for general corporate purposes and as backup for commercial paper borrowings, and also permit the issuance of standby letters of credit. PGE may borrow for one, two, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the applicable credit facility. Both revolving credit facilities contain two, one-year extensions subject to approval by the banks, require annual fees based on PGE's unsecured credit ratings, and contain customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the agreement, to 65.0% of total capitalization. As of December 31, 2013, PGE was in compliance with this covenant with a 51.3% debt to total capital ratio.

PGE classifies any borrowings under the revolving credit facilities and outstanding commercial paper as Short-term debt in the consolidated balance sheets. As of December 31, 2013, PGE had no borrowings or commercial paper outstanding, $37 million of letters of credit issued, and an aggregate available capacity of $663 million under the revolving credit facilities.

PGE also has two one-year $30 million letter of credit facilities, which are scheduled to terminate in September and October 2014. As of December 31, 2013, PGE had issued an additional $37 million of letters of credit under the facilities, with an aggregate available capacity of $23 million under these facilities.

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

Pursuant to an order issued by the FERC, the Company is authorized to issue short-term debt up to $900 million through February 6, 2016. The authorization provides that if utility assets financed by unsecured debt are divested, then a proportionate share of the unsecured debt must also be divested.

Short-term borrowings under these credit facilities and related interest rates were as follows (dollars in millions):

	Years Ended December 31,		
	2013	2012	2011
Average daily amount of short-term debt outstanding	$ 9	$ 4	$ 2
Weighted daily average interest rate *	0.4%	0.4%	0.4%
Maximum amount outstanding during the year	$ 54	$ 44	$ 44

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

NOTE 9: LONG-TERM DEBT

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

	As of December 31,	
	2013	2012
First Mortgage Bonds, rates range from 3.46% to 9.31%, with a weighted average rate of 5.62% in 2013 and 5.84% in 2012, due at various dates through 2048	$ 1,795	$ 1,515
Pollution Control Revenue Bonds, 5% rate, due 2033	148	142
Pollution Control Revenue Bonds owned by PGE	(27)	(21)
Total long-term debt	1,916	1,636
Less: current portion of long-term debt	—	(100)
Long-term debt, net of current portion	$ 1,916	$ 1,536

First Mortgage Bonds—During 2013, PGE repaid a total of $100 million of First Mortgage Bonds (FMBs), in accordance with the terms of the debt agreements, and issued a total of $380 million of FMBs, consisting of the following:

- In December, issued $50 million of 4.84% Series FMBs due 2048;
- In November, issued $105 million of 4.74% Series FMBs due 2042;
- In August, repaid $50 million of 5.625% Series FMBs and issued $75 million of 4.47% Series FMBs due 2043;
- In June, issued $150 million of 4.47% Series FMBs due 2044; and
- In April, repaid $50 million of 4.45% Series FMBs.

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

Pollution Control Revenue Bonds—Of the $27 million of Pollution Control Bonds held by the Company, PGE has the option to remarket $21 million through 2033. The Company retired $6 million of Pollution Control Bonds in January 2014. At the time of any remarketing, PGE can choose a new interest rate period that could be daily, weekly, or a fixed term. The new interest rate would be based on market conditions at the time of remarketing. The Pollution Control Revenue Bonds could be backed by FMBs or a bank letter of credit depending on market conditions.

As of December 31, 2013, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:		
2015	$	70
2016		67
2017		58
2018		75
Thereafter		1,646
	$	1,916

Interest is payable semi-annually on all long-term debt instruments.

NOTE 10: EMPLOYEE BENEFITS

Pension and Other Postretirement Plans

Defined Benefit Pension Plan—PGE sponsors a non-contributory defined benefit pension plan. The plan has been closed to most new employees since January 31, 2009 and to all new employees since January 1, 2012. No changes were made to the benefits provided to existing participants when the plan was closed to new employees.

The assets of the pension plan are held in a trust and are comprised of equity and debt instruments, all of which are recorded at fair value. Pension plan calculations include several assumptions which are reviewed annually and are updated as appropriate, with the measurement date of December 31.

PGE made no contributions to the pension plan in 2013 and 2012, and contributed $26 million to the plan in 2011. No contributions to the pension plan are expected in 2014.

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

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

Contributions to the HRAs provide for claims by retirees for qualified medical costs. For bargaining employees, the participants' accounts are credited with 58% of the value of the employee's accumulated sick time as of April 30, 2004, a stated amount per compensable hour worked, plus 100% of their earned time off accumulated at the time of retirement. For active non-bargaining employees, the Company grants a fixed dollar amount that will become available for qualified medical expenses upon their retirement.

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

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

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

	2013			2012		
	NQBP	**Other NQBP**	**Total**	**NQBP**	**Other NQBP**	**Total**
Non-qualified benefit plan trust.............	$ 16	$ 19	$ 35	$ 15	$ 17	$ 32
Non-qualified benefit plan liabilities *...	22	79	101	25	77	102

* For the NQBP, excludes the current portion of $2 million in 2013 and 2012, which is classified in Other current liabilities in the consolidated balance sheets.

See "*Trust Accounts*" in Note 3, Balance Sheet Components, for information on the Non-qualified benefit plan trust.

Investment Policy and Asset Allocation—The Board of Directors of PGE appoints an Investment Committee, which is comprised of officers of the Company. In addition, the Board also establishes the Company's asset allocation. The Investment Committee is then responsible for implementation and oversight of the asset allocation. The Company's investment policy for its pension and other postretirement plans is to balance risk and return through a diversified portfolio of equity securities, fixed income securities and other alternative investments. The commitments to each class are controlled by an asset deployment and cash management strategy that takes profits from asset classes whose allocations have shifted above their target ranges to fund benefit payments and investments in asset classes whose allocations have shifted below their target ranges.

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

	As of December 31,			
	2013		2012	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Equity securities	67%	67%	68%	67%
Debt securities	33	33	32	33
Total	100%	100%	100%	100%
Other Postretirement Benefit Plans:				
Equity securities	58%	58%	63%	72%
Debt securities	42	42	37	28
Total	100%	100%	100%	100%
Non-Qualified Benefits Plans:				
Equity securities	24%	16%	17%	17%
Debt securities	1	9	6	10
Insurance contracts	75	75	77	73
Total	100%	100%	100%	100%

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

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

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

	Level 1	Level 2	Level 3	Total
As of December 31, 2013:				
Defined Benefit Pension Plan assets:				
Equity securities:				
Domestic	$ 166	$ 19	$ —	$ 185
International	185	—	—	185
Debt securities:				
Domestic government and corporate credit	—	181	—	181
Corporate credit	14	—	—	14
Private equity funds	—	—	31	31
	$ 365	$ 200	$ 31	$ 596
Other Postretirement Benefit Plans assets:				
Money market funds	$ —	$ 10	$ —	$ 10
Equity securities:				
Domestic	8	2	—	10
International	9	—	—	9
Debt securities—Domestic government	3	—	—	3
	$ 20	$ 12	$ —	$ 32
As of December 31, 2012:				
Defined Benefit Pension Plan assets:				
Money market funds	$ —	$ 1	$ —	$ 1
Equity securities:				
Domestic	150	15	—	165
International	166	—	—	166
Debt securities:				
Domestic government and corporate credit	—	165	—	165
Corporate credit	8	—	—	8
Private equity funds	—	—	32	32
	$ 324	$ 181	$ 32	$ 537
Other Postretirement Benefit Plans assets:				
Money market funds	$ —	$ 8	$ —	$ 8
Equity securities:				
Domestic	8	1	—	9
International	8	—	—	8
Debt securities—Domestic government	3	—	—	3
	$ 19	$ 9	$ —	$ 28

An overview of the identification of Level 1, 2, and 3 financial instruments is provided in Note 4, Fair Value of Financial Instruments. The following methods are used in valuation of each asset class of investments held in the pension and other postretirement benefit plan trusts.

Money market funds—PGE invests in money market funds that seek to maintain a stable net asset value. These funds invest in high-quality, short-term, diversified money market instruments, short term treasury bills, federal agency securities, certificates of deposit, and commercial paper. Money market funds held in the trusts are classified as Level 2 instruments as they are traded in an active market of similar securities but are not directly valued using quoted prices.

Equity securities—Equity mutual fund and common stock securities are primarily classified as Level 1 securities based on unadjusted prices in an active market. Principal markets for equity prices include published exchanges such as NASDAQ and NYSE. Certain mutual fund assets included in commingled trusts or separately managed accounts are classified as Level 2 securities due to pricing inputs that are not directly or indirectly observable in the marketplace.

Debt securities—PGE invests in highly-liquid United States treasury and corporate credit mutual fund securities to support the investment objectives of the trusts. These securities are classified as Level 1 instruments due to the highly observable nature of pricing in an active market.

Fair values for Level 2 debt securities, including municipal debt and corporate credit securities, mortgage-backed securities and asset-backed securities are determined by evaluating pricing data, such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in valuation models generally include benchmark yield and issuer spreads. The external credit rating, coupon rate, and maturity of each security are considered in the valuation if applicable.

Private equity funds—PGE invests in a combination of primary and secondary fund-of-funds which hold ownership positions in privately held companies across the major domestic and international private equity sectors, including but not limited to, venture capital, buyout and special situations. Private equity investments are classified as Level 3 securities due to fund valuation methodologies that utilize discounted cash flow, market comparable and limited secondary market pricing to develop estimates of fund valuation. PGE valuation of individual fund performance compares stated fund performance against published benchmarks.

Changes in the fair value of assets held by the pension plan classified as Level 3 in the fair value hierarchy were as follows (in millions):

	Years Ended December 31,			
	2013	2012		
	Private equity funds	Private equity funds	Alternative investments	Total
Level 3 balance as of beginning of year	$ 32	$ 32	$ 30	$ 62
Unrealized gains (losses), net	4	2	(6)	(4)
Realized gains (losses), net	(2)	(1)	6	5
Sales, net	(3)	(1)	(30)	(31)
Level 3 balance as of end of year	$ 31	$ 32	$ —	$ 32

The following tables provide certain information with respect to the Company's defined benefit pension plan, other postretirement benefits, and non-qualified benefit plans as of and for the years ended December 31, 2013 and 2012. Information related to the Other NQBP is not included in the following tables (dollars in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2013	2012	2013	2012	2013	2012
Benefit obligation:						
As of January 1	$ 728	$ 634	$ 84	$ 75	$ 27	$ 27
Service cost	17	14	2	2	—	—
Interest cost	30	31	3	3	1	1
Participants' contributions	—	—	2	2	—	—
Actuarial (gain) loss	(38)	77	(9)	7	(2)	1
Contractual termination benefits	—	—	1	1	—	—
Benefit payments	(32)	(28)	(6)	(6)	(2)	(2)
As of December 31	$ 705	$ 728	$ 77	$ 84	$ 24	$ 27
Fair value of plan assets:						
As of January 1	$ 537	$ 487	$ 28	$ 27	$ 15	$ 17
Actual return on plan assets	91	78	5	3	3	—
Company contributions	—	—	3	2	—	—
Participants' contributions	—	—	2	2	—	—
Benefit payments	(32)	(28)	(6)	(6)	(2)	(2)
As of December 31	$ 596	$ 537	$ 32	$ 28	$ 16	$ 15
Unfunded position as of December 31	$ (109)	$ (191)	$ (45)	$ (56)	$ (8)	$ (12)
Accumulated benefit plan obligation as of December 31	$ 631	$ 640	N/A	N/A	$ 24	$ 27
Classification in consolidated balance sheet:						
Noncurrent asset	$ —	$ —	$ —	$ —	$ 16	$ 15
Current liability	—	—	—	—	(2)	(2)
Noncurrent liability	(109)	(191)	(45)	(56)	(22)	(25)
Net liability	$ (109)	$ (191)	$ (45)	$ (56)	$ (8)	$ (12)
Amounts included in comprehensive income:						
Net actuarial (gain) loss	$ (89)	$ 40	$ (11)	$ 5	$ (1)	$ 2
Amortization of net actuarial loss	(24)	(17)	(1)	(1)	(1)	(1)
Amortization of prior service cost	—	—	(1)	(1)	—	—
	$ (113)	$ 23	$ (13)	$ 3	$ (2)	$ 1
Amounts included in AOCL*:						
Net actuarial loss	$ 186	$ 298	$ 6	$ 18	$ 9	$ 11
Prior service cost	—	1	2	4	—	—
	$ 186	$ 299	$ 8	$ 22	$ 9	$ 11

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2013	2012	2013	2012	2013	2012
Assumptions used:						
Discount rate for benefit obligation	4.84%	4.24%	3.46%-4.96%	2.77%-4.13%	4.84%	4.24%
Discount rate for benefit cost	4.24%	5.00%	2.77%-4.13%	3.76%-4.90%	4.24%	5.00%
Weighted average rate of compensation increase for benefit obligation	3.65%	3.65%	4.58%	4.58%	N/A	N/A
Weighted average rate of compensation increase for benefit cost	3.65%	3.71%	4.58%	4.58%	N/A	N/A
Long-term rate of return on plan assets for benefit obligation	7.50%	8.25%	6.46%	6.50%	N/A	N/A
Long-term rate of return on plan assets for benefit cost	8.25%	8.25%	5.89%	7.09%	N/A	N/A

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

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

	Defined Benefit Pension Plan			Other Postretirement Benefits			Non-Qualified Benefit Plans		
	2013	2012	2011	2013	2012	2011	2013	2012	2011
Service cost	$ 17	$ 14	$ 12	$ 2	$ 2	$ 2	$ —	$ —	$ —
Interest cost on benefit obligation	30	31	29	3	3	4	1	1	1
Expected return on plan assets	(40)	(41)	(42)	(1)	(1)	(1)	—	—	—
Amortization of prior service cost	—	—	1	1	1	1	—	—	—
Amortization of net actuarial loss	24	17	8	1	1	1	1	1	1
Net periodic benefit cost	$ 31	$ 21	$ 8	$ 6	$ 6	$ 7	$ 2	$ 2	$ 2

PGE estimates that $20 million will be amortized from AOCL into net periodic benefit cost in 2014, consisting of a net actuarial loss of $17 million for pension benefits, $1 million for non-qualified benefits and $1 million for other postretirement benefits, and prior service cost of $1 million for other postretirement benefits.

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

	Payments Due					
	2014	2015	2016	2017	2018	2019 - 2023
Defined benefit pension plan	$ 34	$ 36	$ 37	$ 39	$ 40	$ 219
Other postretirement benefits	5	5	5	5	5	26
Non-qualified benefit plans	2	2	2	2	2	10
Total	$ 41	$ 43	$ 44	$ 46	$ 47	$ 255

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

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

- For 2013, 7.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2014, and assumed to decrease 0.5% per year thereafter, reaching 5% in 2019;
- For 2012, 8% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2013, and assumed to decrease 0.5% per year thereafter, reaching 5% in 2019; and
- For 2011, 8% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2012 through 2013, and assumed to decrease 0.5% per year thereafter, reaching 5% in 2019.

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

401(k) Retirement Savings Plan

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

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

All contributions are invested in accordance with employees' elections, limited to investment options available under the 401(k) Plan. PGE made contributions to employee accounts of $16 million in 2013, 2012, and 2011.

NOTE 11: INCOME TAXES

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

	Years Ended December 31,		
	2013	2012	2011
Current:			
Federal	$ 10	$ 16	$ 2
State and local	—	1	—
	10	17	2
Deferred:			
Federal	4	30	43
State and local	7	17	13
	11	47	56
Income tax expense	$ 21	$ 64	$ 58

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

	Years Ended December 31,		
	2013	2012	2011
Federal statutory tax rate	35.0%	35.0%	35.0%
Federal tax credits	(21.8)	(11.8)	(12.7)
State and local taxes, net of federal tax benefit	3.4	3.5	2.6
Adjustment to deferred taxes for change in blended composite state tax rate	—	2.6	—
Flow through depreciation and cost basis differences	2.8	2.4	2.1
Other	(2.6)	(0.6)	1.3
Effective tax rate	16.8%	31.1%	28.3%

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

	As of December 31,	
	2013	2012
Deferred income tax assets:		
Employee benefits	$ 122	$ 162
Price risk management	71	77
Tax credits	51	55
Regulatory liabilities	16	20
Other	17	—
Total deferred income tax assets	277	314
Deferred income tax liabilities:		
Depreciation and amortization	646	623
Regulatory assets	175	224
Other	—	4
Total deferred income tax liabilities	821	851
Deferred income tax liability, net	$ (544)	$ (537)
Classification of net deferred income taxes:		
Current deferred income tax asset [(1)]	$ 42	$ 51
Noncurrent deferred income tax liability	(586)	(588)
	$ (544)	$ (537)

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

As of December 31, 2013, PGE has federal and state tax credit carryforwards of $40 million and $11 million, respectively, which will expire at various dates from 2016 through 2035.

PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2013 and 2012 will be realized; accordingly, no valuation allowance has been recorded. During the year ended December 31, 2011, the valuation allowance decreased $2 million as a result of the expiration of unused state credits.

As of December 31, 2013 and 2012, PGE had no unrecognized tax benefits. During 2011, an unrecognized tax benefit of $2 million was recognized as a result of filing for a federal tax accounting method change.

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

On September 13, 2013, the U.S. Department of Treasury and the IRS issued final regulations regarding the deduction and capitalization of expenditures related to tangible property. The final regulations under Internal Revenue Code Section 162, 167 and 263(a) apply to amounts paid to acquire, produce, or improve tangible property, as well as dispositions of such property and are generally effective for tax years beginning on or after January 1, 2014. The Company has evaluated these regulations and has determined they will not have a material impact on its consolidated financial position, consolidated results of operations, or consolidated cash flows.

NOTE 12: EQUITY-BASED PLANS

Equity Forward Sale Agreement

On June 11, 2013, PGE entered into an equity forward sale agreement (EFSA) in connection with a public offering of 11,100,000 shares of its common stock. The underwriters exercised their over-allotment option in full in connection with such public offering and on June 17, 2013, PGE separately issued 1,665,000 shares of PGE common stock for $28.54 per share, net of the underwriters' discount, or net proceeds of $47 million. In August, the Company issued 700,000 shares for net proceeds of $20 million pursuant to the EFSA.

Pursuant to the terms of the EFSA, a forward counterparty borrowed 11,100,000 shares of PGE's common stock from third parties in the open market and sold the shares to a group of underwriters for $29.50 per share, less an underwriting discount equal to $0.96 per share. The underwriters then sold the shares in a public offering. PGE receives proceeds from the sale of common stock when the EFSA is physically settled (described below), and at that time PGE records the proceeds in equity.

Under the terms of the EFSA, PGE may elect to settle the equity forward transactions by means of: (1) physical; (2) cash; or (3) net share settlement, in whole or in part, at any time on or prior to June 11, 2015, except in specified circumstances or events that would require physical settlement. To the extent that the transactions are physically settled, PGE would be required to issue and deliver shares of PGE common stock to the forward counterparty at the then applicable forward sale price. The forward sale price was initially determined to be $29.50 per share at the time the EFSA was entered into, and the amount of cash to be received by PGE upon physical settlement of the EFSA is subject to certain adjustments in accordance with the terms of the EFSA.

The use of the EFSA substantially eliminates future equity market price risk by fixing the common stock offering sales price under the then existing market conditions, while mitigating immediate share dilution resulting from the offering by postponing the actual issuance of common stock until such funds are needed in accordance with the Company's capital requirements. The EFSA had no initial fair value since it was entered into at the then market price of the common stock. PGE concluded that the EFSA was an equity instrument and that it does not qualify as a derivative because the EFSA was indexed to the Company's stock. PGE anticipates settling the EFSA through physical settlement on or before June 11, 2015.

At December 31, 2013, the Company could have physically settled the EFSA by delivering 10,400,000 shares to the forward counterparty in exchange for cash of $288 million. In addition, at December 31, 2013, the Company could have elected to make a cash settlement by paying approximately $26 million, or a net share settlement by delivering approximately 876,318 shares of common stock. To the extent that PGE makes a cash or net share settlement, the Company would receive no additional proceeds from the public offering.

Prior to settlement, the potentially issuable shares pursuant to the EFSA will be reflected in PGE's diluted earnings per share calculations using the treasury stock method. Under this method, the number of shares of PGE's common stock used in calculating diluted earnings per share for a reporting period would be increased by the number of shares, if any, that would be issued upon physical settlement of the EFSA less the number of shares that could be purchased by PGE in the market with the proceeds received from issuance (based on the average market price during that reporting period).

Employee Stock Purchase Plan

PGE has an employee stock purchase plan (ESPP), under which a total of 625,000 shares of the Company's common stock may be issued. The ESPP permits all eligible employees to purchase shares of PGE common stock through regular payroll deductions, which are limited to 10% of base pay. Each year, employees may purchase up to a maximum of $25,000 in common stock (based on fair value on the purchase date) or 1,500 shares, whichever is less. There are two six-month offering periods each year, January 1 through June 30 and July 1 through December 31, during which eligible employees may purchase shares of PGE common stock at a price equal to 95% of the fair value of the stock on the purchase date, the last day of the offering period. As of December 31, 2013, there were 451,506 shares available for future issuance pursuant to the ESPP.

Dividend Reinvestment and Direct Stock Purchase Plan

On April 1, 2011, PGE's Dividend Reinvestment and Direct Stock Purchase Plan (DRIP) became effective, under which a total of 2,500,000 shares of the Company's common stock may be issued. Under the DRIP, investors may elect to buy shares of the Company's common stock or elect to reinvest cash dividends in additional shares of the Company's common stock. As of December 31, 2013, there were 2,485,055 shares available for future issuance pursuant to the DRIP.

NOTE 13: STOCK-BASED COMPENSATION EXPENSE

Pursuant to the Portland General Electric Company 2006 Stock Incentive Plan (the Plan), the Company may grant a variety of equity-based awards, including restricted stock units with time-based vesting conditions and performance-based vesting conditions to non-employee directors, officers and certain key employees. Service requirements generally must be met for stock units to vest. For each grant, the number of restricted stock units is determined by dividing the specified award amount for each grantee by the closing stock price on the date of grant. A total of 4,687,500 shares of common stock were registered for future issuance under the Plan, of which 3,701,833 shares remain available for future issuance as of December 31, 2013.

Time-based restricted stock units vest in either equal installments over a one-year period on the last day of each calendar quarter, over a three-year period on each anniversary of the grant date, or at the end of a three-year period following the grant date.

Performance-based restricted stock units vest if performance goals are met at the end of a three-year performance period. For grants prior to March 5, 2013, such goals include return on equity relative to allowed return on equity, and regulated asset base growth. Grants on and after March 5, 2013 are based on three equally-weighted metrics: return on equity relative to allowed return on equity; regulated asset growth; and a total shareholder return (TSR) relative to the Edison Electric Institute Regulated Index (EEI Index). Vesting of performance-based restricted stock units is calculated by multiplying the number of units granted by a performance percentage determined by the Compensation and Human Resources Committee of PGE's Board of Directors. The performance percentage is calculated based on the extent to which the performance goals are met. In accordance with the Plan, however, the committee may disregard or offset the effect of extraordinary, unusual or non-recurring items in determining results relative to these goals. Based on the attainment of the performance goals, the awards can range from zero to 150% of the grant.

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

Restricted stock unit activity is summarized in the following table:

	Units	Weighted Average Grant Date Fair Value
Outstanding as of December 31, 2010	465,428	$ 17.88
Granted	152,657	23.84
Forfeited	(106,979)	22.35
Vested	(19,702)	23.34
Outstanding as of December 31, 2011	491,404	18.54
Granted	186,495	24.72
Forfeited	(22,947)	18.95
Vested	(214,390)	15.67
Outstanding as of December 31, 2012	440,562	22.54
Granted	183,071	29.25
Forfeited	(7,007)	27.15
Vested	(185,536)	20.20
Outstanding as of December 31, 2013	431,090	26.31

The Company withholds a portion of the vested shares for the payment of income taxes on behalf of the employees. The total value of time- and performance-based stock units vested during the years ended December 31, 2013, 2012, and 2011 was $4 million, $3 million and $1 million, respectively. The weighted average fair value of the return on equity and regulated asset base growth portions of the grants is measured based on the closing price of PGE common stock on the date of grant. The fair value of these awards is charged to compensation expense over the requisite service period based on the number of shares expected to vest. Stock-based compensation expense was calculated assuming the attainment of performance goals that would allow the weighted average vesting of 110.7%, 109.2%, and 107.8% of awarded performance-based restricted stock units for 2013, 2012, and 2011, respectively, with an estimated 5% forfeiture rate. The weighted average fair value of the TSR portion is determined using a Monte Carlo simulation model utilizing actual information for the common shares of PGE and its peer group for the period from the beginning of the performance period to the grant date and estimated future stock volatility over the remaining performance period. The estimated TSR grant date fair value is 99.7% of the grant price. The fair value of these awards is charged to compensation expense over the requisite service period, regardless of the level of TSR metric actually attained. The assumptions used in the Monte Carlo model are summarized as follows:

	2013
Stock price at March 5, 2013	$ 30.29
Risk-free rate	0.34%
Expected term (in years)	3
Expected volatility	16.77%
Range of expected volatility for EEI Index	12.06% - 25.13%
Dividend yield	0%

For the years ended December 31, 2013, 2012, and 2011, PGE recorded stock-based compensation expense of $4 million, which is included in Administrative and other expense in the consolidated statements of income. Such amounts differ from those reported in the consolidated statements of equity for Stock-based compensation due primarily to the impact from the income tax payments made on behalf of employees. The net impact to equity from the income tax payments, partially offset by the issuance of DERs, resulted in a charge to equity of $2 million in 2013, $1 million in 2012, and less than $1 million in 2011, which is not included in Administrative and other expenses in the consolidated statements of income.

As of December 31, 2013, unrecognized stock-based compensation expense was $4 million, of which approximately $3 million and $1 million is expected to be expensed in 2014 and 2015, respectively. No stock-based compensation costs have been capitalized and the Plan had no material impact on cash flows for the years ended December 31, 2013, 2012, or 2011.

NOTE 14: EARNINGS PER SHARE

Basic earnings per share is computed based on the weighted average number of common shares outstanding during the year. Diluted earnings per share is computed using the weighted average number of common shares outstanding and the effect of dilutive potential common shares outstanding during the year using the treasury stock method. Potential common shares consist of: (i) employee stock purchase plan shares; (ii) unvested time-based and performance-based restricted stock units, along with associated dividend equivalent rights; and (iii) shares issuable pursuant to the EFSA. See Note 12, Equity-based Plans, for additional information on the EFSA and its impact on earnings per share. Unvested performance-based restricted stock units and associated dividend equivalent rights are included in dilutive potential common shares only after the performance criteria has been met.

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

	Years Ended December 31,		
	2013	2012	2011
Weighted average common shares outstanding—basic	76,821	75,498	75,333
Dilutive effect of potential common shares	567	149	17
Weighted average common shares outstanding—diluted	77,388	75,647	75,350

NOTE 15: COMMITMENTS AND GUARANTEES

Commitments

As of December 31, 2013, PGE's estimated future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2014	2015	2016	2017	2018	Thereafter	Total
Capital and other purchase commitments	$ 710	$ 113	$ 40	$ 2	$ 2	$ 67	$ 934
Purchased power and fuel:							
Electricity purchases	240	159	150	125	126	683	1,483
Capacity contracts	22	23	22	2	2	1	72
Public Utility Districts	8	8	7	5	5	33	66
Natural gas	65	21	12	10	8	6	122
Coal and transportation	21	6	6	6	4	5	48
Operating leases	11	9	10	10	10	191	241
Total	$ 1,077	$ 339	$ 247	$ 160	$ 157	$ 986	$ 2,966

Capital and other purchase commitments—Certain commitments have been made for capital and other purchases for 2014 and beyond. Such commitments include those related to hydro licenses, upgrades to generating, distribution and transmission facilities, information systems, and system maintenance work. A large component of these commitments for 2014 and 2015 are costs associated with the construction of three new generating facilities. Termination of these agreements could result in cancellation charges.

Electricity purchases and Capacity contracts—PGE has power purchase contracts with counterparties, which expire at varying dates through 2037, and power capacity contracts through 2019. In addition to the power purchase contracts with counterparties presented in the table, PGE has power sale contracts with counterparties of approximately $1 million that settle in 2014.

Public Utility Districts—PGE has long-term power purchase contracts with certain public utility districts in the state of Washington and with the City of Portland, Oregon. The Company is required to pay its proportionate share of the operating and debt service costs of the hydroelectric projects whether or not they are operable. The future minimum payments for the Public Utility Districts in the preceding table reflect the principal payment only and do not include interest, operation, or maintenance expenses. Selected information regarding these projects is summarized as follows (dollars in millions):

	Revenue Bonds as of December 31, 2013	PGE's Share in 2013		Contract Expiration	PGE Cost, including Debt Service		
		Output	Capacity (in MW)		2013	2012	2011
Priest Rapids and Wanapum	$ 1,001	9.0%	170	2052	$ 14	$ 14	$ 14
Wells	232	19.4	150	2018	10	10	10
Portland Hydro	7	100.0	36	2017	4	4	4

Under contracts with the public utility districts, PGE has acquired a percentage of the output (Allocation) of Priest Rapids and Wanapum and Wells. The contracts provide that, should any other purchaser of output default on payments as a result of bankruptcy or insolvency, PGE would be allocated a pro rata share of the output and operating and debt service costs of the defaulting purchaser. For Wells, PGE would be allocated up to a cumulative maximum of 25% of the defaulting purchaser's percentage Allocation. For Priest Rapids and Wanapum, PGE would be allocated up to a cumulative maximum that would not adversely affect the tax exempt status of any outstanding debt.

Natural gas—PGE has agreements for the purchase and transportation of natural gas from domestic and Canadian sources for its natural gas-fired generating facilities. The Company also has a natural gas storage agreement, which expires in April 2017, for the purpose of fueling the Company's Port Westward natural gas-fired generating plant (Port Westward) and Beaver natural gas-fired generating plant (Beaver).

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

Operating leases—PGE has various operating leases associated with its headquarters and certain of its production, transmission, and support facilities. The majority of the future minimum operating lease payments presented in the table consist of (i) the corporate headquarters lease, which expires in 2018, but includes renewal period options through 2043, and (ii) the Port of St. Helens land lease, where Port Westward and Beaver are located, which expires in 2096. Rent expense was $9 million in 2013, $10 million in 2012, and $9 million in 2011.

The future minimum operating lease payments presented is net of sublease income of: $3 million in 2014 and 2015; $2 million in 2016; and $1 million in 2017 and 2018. Sublease income was $3 million in 2013, 2012, and 2011.

Guarantees

PGE enters into financial agreements and power and natural gas purchase and sale agreements that include indemnification provisions relating to certain claims or liabilities that may arise relating to the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. PGE periodically evaluates the likelihood of incurring costs under such indemnities based on the Company's historical experience and the evaluation of the specific indemnities. As of December 31, 2013, management believes the likelihood is remote that PGE would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnities. The Company has not recorded any liability on the consolidated balance sheets with respect to these indemnities.

NOTE 16: VARIABLE INTEREST ENTITIES

PGE has determined that it is the primary beneficiary of three VIEs and, therefore, consolidates the VIEs within the Company's consolidated financial statements. All three arrangements were formed for the sole purpose of designing, developing, constructing, owning, maintaining, operating and financing photovoltaic solar power facilities located on real property owned by third parties, and selling the energy generated by the facilities. The Company is the Managing Member and a financial institution is the Investor Member in each of the Limited Liability Companies (LLCs), holding equity interests of less than 1% and more than 99%, respectively, in each entity. PGE has determined that its interests in these VIEs contain the obligation to absorb the variability of the entities that could potentially be significant to the VIEs, and the Company has the power to direct the activities that most significantly affect the entities' economic performance.

Determining whether PGE is the primary beneficiary of a VIE is complex, subjective and requires the use of judgments and assumptions. Significant judgments and assumptions made by PGE in determining it is the primary beneficiary of these LLCs include the following: (i) PGE has the experience to own and operate electric generating facilities and is authorized to operate the LLCs pursuant to the operating agreements, and, therefore, PGE has control over the most significant activities of the LLCs; (ii) PGE expects to own 100% of the LLCs shortly after five years have elapsed from when the facility was placed in service, at which time the facilities will have approximately 75% of their estimated useful life remaining; and (iii) based on projections prepared in accordance with the operating agreements, PGE expects to absorb a majority of any expected losses of the LLCs.

Included in PGE's consolidated balance sheets as of December 31, 2013 and 2012 are LLC net assets of $5 million and $6 million, respectively, primarily comprised of Electric utility plant, and includes Cash and cash equivalents of $1 million. These assets can only be used to settle the obligations of the consolidated VIEs and their creditors have no recourse to the general credit of PGE.

In January 2014, PGE acquired the equity interest held by the Investor Member of one of the LLCs pursuant to the terms of the operating agreement. The transaction did not have a significant impact to the Company's consolidated financial position, consolidated results of operations or consolidated cash flows.

NOTE 17: JOINTLY-OWNED PLANT

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

In 1985, PGE sold a 15% undivided interest in Boardman and a 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line (jointly, the Facility Assets) to an unrelated third party (Purchaser). Under terms of the original 1985 agreements, on December 31, 2013, PGE acquired the Facility Assets from the Purchaser in exchange for $1 from the Purchaser. PGE assumed responsibility for the ARO related to that 15% interest in Boardman in the amount of $7 million. The acquisition of the 15% interest in Boardman increased the Company's ownership share from 65% to 80% on December 31, 2013.

As of December 31, 2013, PGE had the following investments in jointly-owned plant (dollars in millions):

	PGE Share	In-service Date	Plant In-service	Accumulated Depreciation*	Construction Work In Progress
Boardman	80.00%	1980	$ 506	$ 326	$ 1
Colstrip	20.00	1986	515	332	3
Pelton/Round Butte	66.67	1958 / 1964	222	52	15
Total			$ 1,243	$ 710	$ 19

* Excludes AROs and accumulated asset retirement removal costs.

NOTE 18: CONTINGENCIES

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

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

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

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

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

Trojan Investment Recovery

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

Numerous challenges and appeals were subsequently filed in various state courts on the issue of the OPUC's authority under Oregon law to grant recovery of, and a return on, the Trojan investment. In 1998, the Oregon Court of Appeals upheld the OPUC's order authorizing PGE's recovery of the Trojan investment, but held that the OPUC did not have the authority to allow the Company to recover a return on the Trojan investment and remanded the case to the OPUC for reconsideration.

In 2000, PGE entered into agreements to settle the litigation related to recovery of, and return on, its investment in Trojan. The settlement, which was approved by the OPUC, allowed PGE to remove from its balance sheet the remaining investment in Trojan as of September 30, 2000, along with several largely offsetting regulatory liabilities. After offsetting the investment in Trojan with these liabilities, the remaining Trojan regulatory asset balance of approximately $5 million (after tax) was expensed. As a result of the settlement, PGE's investment in Trojan was no longer included in prices charged to customers, either through a return of or a return on that investment. The Utility Reform Project (URP) did not participate in the settlement and filed a complaint with the OPUC challenging the settlement agreements. In 2002, the OPUC issued an order (2002 Order) denying all of the URP's challenges. In 2007, following several appeals by various parties, the Oregon Court of Appeals issued an opinion that remanded the 2002 Order to the OPUC for reconsideration.

The OPUC then issued an order in 2008 (2008 Order) that required PGE to provide refunds, including interest from September 30, 2000, to customers who received service from the Company during the period from October 1, 2000 to September 30, 2001. The Company recorded a charge of $33.1 million in 2008 related to the refund and accrued additional interest expense on the liability until refunds to customers were completed in the first quarter of 2010. The URP and the plaintiffs in the class actions described below separately appealed the 2008 Order to the Oregon Court of Appeals. On February 6, 2013, the Oregon Court of Appeals issued an opinion that upheld the 2008 Order. On May 31, 2013, the Court of Appeals denied the appellants' request for reconsideration of the decision. On October 18, 2013, the Oregon Supreme Court granted plaintiffs' petition seeking review of the February 6, 2013 Oregon Court of Appeals decision. Opening briefs have been filed with oral argument scheduled for March 4, 2014.

Class Actions. In two separate legal proceedings, lawsuits were filed in Marion County Circuit Court against PGE in 2003 on behalf of two classes of electric service customers. The class action lawsuits seek damages totaling $260 million, plus interest, as a result of the Company's inclusion, in prices charged to customers, of a return on its investment in Trojan.

In 2006, the Oregon Supreme Court issued a ruling ordering the abatement of the class action proceedings until the OPUC responded to the 2002 Order (described above). The Oregon Supreme Court concluded that the OPUC has primary jurisdiction to determine what, if any, remedy can be offered to PGE customers, through price reductions or refunds, for any amount of return on the Trojan investment that the Company collected in prices.

The Oregon Supreme Court further stated that if the OPUC determined that it can provide a remedy to PGE's customers, then the class action proceedings may become moot in whole or in part. The Oregon Supreme Court added that, if the OPUC determined that it cannot provide a remedy, the court system may have a role to play. The Oregon Supreme Court also ruled that the plaintiffs retain the right to return to the Marion County Circuit Court for disposition of whatever issues remain unresolved from the remanded OPUC proceedings. The Marion County Circuit Court subsequently abated the class actions in response to the ruling of the Oregon Supreme Court.

As noted above, on February 6, 2013, the Oregon Court of Appeals upheld the 2008 Order. Because the Oregon Supreme Court has granted the plaintiffs' petition seeking review of that decision, and the class actions described above remain pending, management believes that it is reasonably possible that the regulatory proceedings and class actions could result in a loss to the Company in excess of the amounts previously recorded and discussed above. Because these matters involve unsettled legal theories and have a broad range of potential outcomes, sufficient information is currently not available to determine PGE's potential liability, if any, or to estimate a range of potential loss.

Pacific Northwest Refund Proceeding

In 2001, the FERC called for a hearing to explore whether there may have been unjust and unreasonable charges for spot market sales of electricity in the Pacific Northwest from December 25, 2000 through June 20, 2001 (Pacific Northwest Refund proceeding). During that period, PGE both sold and purchased electricity in the Pacific Northwest. In 2003, the FERC issued an order terminating the proceeding and denying the claims for refunds. Parties appealed various aspects of the FERC order to the U.S. Ninth Circuit Court of Appeals (Ninth Circuit).

In August 2007, the Ninth Circuit issued a decision, concluding that the FERC failed to adequately explain how it considered or examined new evidence showing intentional market manipulation in California and the potential ties to the Pacific Northwest and that the FERC should not have excluded from the Pacific Northwest Refund proceeding purchases of energy made by the California Energy Resources Scheduling (CERS) division in the Pacific Northwest spot market. The Ninth Circuit remanded the case to the FERC to: i) address the new market manipulation evidence in detail and account for the evidence in any future orders regarding the award or denial of refunds in the proceedings; ii) include sales to CERS in its analysis; and iii) further consider its refund decision in light of related, intervening opinions of the court. The Ninth Circuit offered no opinion on the FERC's findings based on the record established by the administrative law judge and did not rule on the FERC's ultimate decision to deny refunds. After denying requests for rehearing, the Ninth Circuit in April 2009 issued a mandate giving immediate effect to its August 2007 order remanding the case to the FERC.

In October 2011, the FERC issued an Order on Remand, establishing an evidentiary hearing to determine whether any seller had engaged in unlawful market activity in the Pacific Northwest spot markets during the December 25, 2000 through June 20, 2001 period by violating specific contracts or tariffs, and, if so, whether a direct connection existed between the alleged unlawful conduct and the rate charged under the applicable contract. The FERC held that the *Mobile-Sierra* public interest standard governs challenges to the bilateral contracts at issue in this proceeding, and the strong presumption under *Mobile-Sierra* that the rates charged under each contract are just and reasonable would have to be specifically overcome before a refund could be ordered. The FERC directed the presiding judge, if necessary, to determine a refund methodology and to calculate refunds, but held that a market-wide remedy was not appropriate, given the bilateral contract nature of the Pacific Northwest spot markets. Certain parties claiming refunds filed requests for rehearing of the Order on Remand.

In December 2012, the FERC issued an order granting an interlocutory appeal of the trial judge's ruling on the scope of the remand proceeding. In this order, the FERC held that its Order on Remand was not intended to alter the general state of the law regarding the *Mobile-Sierra* presumption. The FERC clarified that the *Mobile-Sierra* presumption could be overcome either by: i) a showing that a respondent had violated a contract or tariff and that the violation had a direct connection to the rate charged under the applicable contract; or ii) a showing that the contract rate at issue imposed an excessive burden or seriously harmed the public interest.

On April 5, 2013, and subject to its December 2012 clarification in the interlocutory appeal, the FERC denied rehearing requests from refund proponents that had contested the FERC's use of the *Mobile-Sierra* standard in the remand proceeding, its denial of a market-wide remedy, and the restraints in the Order on Remand that limited the types of evidence that could be introduced in the hearing. However, the FERC granted rehearing on the issue of the appropriate refund period, holding that parties could pursue refunds for transactions between January 1, 2000 and December 24, 2000 under Section 309 of the Federal Power Act by showing violations of a filed tariff or rate schedule or of a statutory requirement. Refund claimants have filed petitions for appeal of the Order on Remand and the Order on Rehearing with the Ninth Circuit.

In its October 2011 Order on Remand, the FERC ordered settlement discussions to be convened before a FERC settlement judge. Pursuant to the settlement proceedings, the Company received notice of two claims and reached agreements to settle both claims for an immaterial amount. The FERC approved both settlements during 2012.

Additionally, the settlement between PGE and certain other parties in the California refund case in Docket No. EL00-95, et seq., approved by the FERC in May 2007, resolved all claims between PGE and the California parties named in the settlement (including CERS) as to transactions in the Pacific Northwest during the settlement period, January 1, 2000 through June 20, 2001, but did not settle potential claims from other market participants relating to transactions in the Pacific Northwest.

The above-referenced settlements resulted in a release for the Company as a named respondent in the ongoing remand proceedings, which are limited to initial and direct claims for refunds, but there remains a possibility that additional claims related to this matter could be asserted against the Company in future proceedings if refunds are ordered against current respondents.

Management believes that this matter could result in a loss to the Company in future proceedings. However, management cannot predict whether the FERC will order refunds, which contracts would be subject to refunds, the basis on which refunds would be ordered, or how such refunds, if any, would be calculated. Due to these uncertainties, sufficient information is currently not available to determine PGE's liability, if any, or to estimate a range of reasonably possible loss.

EPA Investigation of Portland Harbor

A 1997 investigation by the United States Environmental Protection Agency (EPA) of a segment of the Willamette River known as Portland Harbor revealed significant contamination of river sediments. The EPA subsequently included Portland Harbor on the National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) as a federal Superfund site and listed 69 Potentially Responsible Parties (PRPs). PGE was included among the PRPs as it has historically owned or operated property near the river. In January 2008, the EPA requested information from various parties, including PGE, concerning additional properties in or near the original segment of the river under investigation as well as several miles beyond. Subsequently, the EPA has listed additional PRPs, which now number over one hundred.

The Portland Harbor site is currently undergoing a remedial investigation (RI) and feasibility study (FS) pursuant to an Administrative Order on Consent (AOC) between the EPA and several PRPs known as the Lower Willamette Group (LWG), which does not include PGE.

In March 2012, the LWG submitted a draft FS to the EPA for review and approval. The draft FS, along with the RI, provide the framework for the EPA to determine a clean-up remedy for Portland Harbor that will be documented in a Record of Decision, which the EPA is expected to issue in 2015 or 2016.

The draft FS evaluates several alternative clean-up approaches. These approaches would take from two to 28 years with costs ranging from $169 million to $1.8 billion, depending on the selected remedial action levels and the choice of remedy. The draft FS does not address responsibility for the costs of clean-up, allocate such costs among PRPs, or define precise boundaries for the clean-up. Responsibility for funding and implementing the EPA's selected clean-up will be determined after the issuance of the Record of Decision.

Management believes that it is reasonably possible that this matter could result in a loss to the Company. However, due to the uncertainties discussed above, sufficient information is currently not available to determine PGE's liability for the cost of any required investigation or remediation of the Portland Harbor site or to estimate a range of potential loss.

DEQ Investigation of Downtown Reach

The Oregon Department of Environmental Quality (DEQ) has executed a memorandum of understanding with the EPA to administer and enforce clean-up activities for portions of the Willamette River that are upriver from the Portland Harbor Superfund site (the Downtown Reach). In January 2010, the DEQ issued an order requiring PGE to perform an investigation of certain portions of the Downtown Reach. PGE completed this investigation in December 2011 and entered into a consent order with the DEQ in July 2012 to conduct a feasibility study of alternatives for remedial action for the portions of the Downtown Reach that were included within the scope of PGE's investigation. The draft feasibility study report, which describes possible remediation alternatives that range in estimated cost from $3 million to $8 million, is expected to be submitted to the DEQ in late February 2014. Using the Company's best estimate of the probable cost for the remediation effort from the set of alternatives provided in the draft feasibility study report, PGE recorded a $3 million reserve for this matter as of December 31, 2013.

Based on the available evidence of previous rate recovery of incurred environmental remediation costs for PGE , as well as for other utilities operating within the same jurisdiction, the Company has concluded that the estimated cost of $3 million to remediate the Downtown Reach is probable of recovery. As a result, the Company also recorded a regulatory asset of $3 million for future recovery in prices as of December 31, 2013. The Company included recovery of the regulatory asset in its 2015 General Rate Case filed with the OPUC in February 2014.

Alleged Violation of Environmental Regulations at Colstrip

On July 30, 2012, PGE received a Notice of Intent to Sue (Notice) for violations of the Clean Air Act (CAA) at Colstrip Steam Electric Station (CSES) from counsel on behalf of the Sierra Club and the Montana Environmental Information Center (MEIC). The Notice was also addressed to the other CSES co-owners, including PPL Montana, LLC, the operator of CSES. PGE has a 20% ownership interest in Units 3 and 4 of CSES. The Notice alleges certain violations of the CAA, including New Source Review, Title V, and opacity requirements, and states that the Sierra Club and MEIC will: i) request a United States District Court to impose injunctive relief and civil penalties; ii) require a beneficial environmental project in the areas affected by the alleged air pollution; and iii) seek reimbursement of Sierra Club's and MEIC's costs of litigation and attorney's fees.

The Sierra Club and MEIC asserted that the CSES owners violated the Title V air quality operating permit during portions of 2008 and 2009 and that the owners have violated the CAA by failing to timely submit a complete air quality operating permit application to the Montana Department of Environmental Quality (MDEQ). The Sierra Club and MEIC also asserted violations of opacity provisions of the CAA.

On March 6, 2013, the Sierra Club and MEIC sued the CSES co-owners, including PGE, for these and additional alleged violations of various environmental related regulations. The plaintiffs are seeking relief that includes an injunction preventing the co-owners from operating CSES except in accordance with the CAA, the Montana State Implementation Plan, and the plant's federally enforceable air quality permits. In addition, plaintiffs are seeking civil penalties against the co-owners including $32,500 per day for each violation occurring through January 12, 2009, and $37,500 per day for each violation occurring thereafter. On May 3, 2013, the defendants filed a motion to dismiss 36 of the 39 claims in the suit. On September 27, 2013, the plaintiffs filed an amended complaint that deleted the Title V and opacity claims, added claims associated with two 2011 projects, and expanded the scope of certain claims to encompass approximately 40 additional projects. This matter is scheduled for trial in March 2015.

Management believes that it is reasonably possible that this matter could result in a loss to the Company. However, due to the uncertainties concerning this matter, PGE cannot predict the outcome or determine whether it would have a material impact on the Company.

Challenge to AOC Related to Colstrip Wastewater Facilities

In August 2012, the operator of CSES entered into an AOC with the MDEQ, which established a comprehensive process to investigate and remediate groundwater seepage impacts related to the wastewater facilities at CSES. Within five years, under this AOC, the operator of CSES is required to provide financial assurance to MDEQ for the costs associated with closure of the waste water treatment facilities. This will establish an obligation for asset retirement, but the operator of CSES is unable at this time to estimate these costs, which will require both public and agency review.

In September 2012, Earthjustice filed an affidavit pursuant to Montana's Major Facility Siting Act (MFSA) that sought review of the AOC by Montana's Board of Environmental Review (BER), on behalf of environmental groups Sierra Club, the MEIC, and the National Wildlife Federation. In September 2012, the operator of CSES filed an election with the BER to have this proceeding conducted in Montana state district court as contemplated by the MFSA. In October 2012, Earthjustice, on behalf of Sierra Club, the MEIC and the National Wildlife Federation, filed with the Montana state district court a petition for a writ of mandamus and a complaint for declaratory relief alleging that the AOC fails to require the necessary actions under the MFSA and the Montana Water Quality Act with respect to groundwater seepage from the wastewater facilities at CSES. On May 31, 2013, the district court judge granted the defendants' motion to dismiss the petition for the writ of mandamus.

Management believes that it is reasonably possible that this matter could result in a loss to the Company. However, due to the uncertainties concerning this matter, PGE cannot predict the outcome or determine whether it would have a material impact on the Company.

Oregon Tax Court Ruling

On September 17, 2012, the Oregon Tax Court issued a ruling contrary to an Oregon Department of Revenue (DOR) interpretation and a current Oregon administrative rule, regarding the treatment of wholesale electricity sales. The underlying issue is whether electricity should be treated as tangible or intangible property for state income tax apportionment purposes. The DOR has appealed the ruling of the Oregon Tax Court to the Oregon Supreme Court.

If the ruling is upheld, PGE estimates that its income tax liability could increase by as much as $7 million due to an increase in the tax rate at which deferred tax liabilities would be recognized in future years. For open tax years per Oregon statute, 2008 through 2012, the Company entered into a closing agreement with the DOR during the third quarter 2013 under which the DOR agreed to the tax apportionment methodology utilized on the tax returns relating to those years. PGE cannot predict the outcome of this matter.

Other Matters

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

QUARTERLY FINANCIAL DATA

(Unaudited)

	Quarter Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share amounts)			
2013				
Revenues, net	$ 473	$ 403	$ 435	$ 499
Income (loss) from operations [1]	87	(11)	53	77
Net income (loss) [1]	48	(22)	31	47
Net income (loss) attributable to Portland General Electric Company [1]	49	(22)	31	47
Earnings (loss) per share—basic and diluted [1] [2]	0.65	(0.29)	0.40	0.59
2012				
Revenues, net	$ 479	$ 413	$ 450	$ 463
Income from operations	88	61	82	71
Net income	49	26	37	28
Net income attributable to Portland General Electric Company	49	26	38	28
Earnings per share—basic and diluted [2]	0.65	0.34	0.50	0.38

(1) The quarter ended June 30 includes $52 million of costs expensed related to the Company's Cascade Crossing Transmission Project and a refund of revenues of $9 million related to the over-billing of an industrial customer since 2009.

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

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

None.

ITEM 9A. CONTROLS AND PROCEDURES.

(a) Disclosure Controls and Procedures

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

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

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

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company's internal control over financial reporting as of the end of the period covered by this report pursuant to Rule 13a-15(c) under the Exchange Act. Management's assessment was based on the framework established in *Internal Control-Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management has concluded that, as of December 31, 2013, the Company's internal control over financial reporting is effective.

The Company's internal control over financial reporting, as of December 31, 2013, has been audited by Deloitte & Touche LLP, the independent registered public accounting firm who audits the Company's consolidated financial statements, as stated in their report included in Item 8.—"Financial Statements and Supplementary Data," which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting, as of December 31, 2013.

(c) Changes in Internal Control over Financial Reporting

There have not been any changes in the Company's internal control over financial reporting during the fourth quarter of 2013 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

The information required by Item 10 is incorporated herein by reference to the relevant information under the captions “Section 16(a) Beneficial Ownership Reporting Compliance,” “Corporate Governance,” “Proposal 1: Election of Directors,” and “Executive Officers” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 7, 2014.

ITEM 11. EXECUTIVE COMPENSATION.

The information required by Item 11 is incorporated herein by reference to the relevant information under the captions “Corporate Governance—Non-Employee Director Compensation,” “Corporate Governance—Compensation Committee Interlocks and Insider Participation,” “Compensation and Human Resources Committee Report,” “Compensation Discussion and Analysis,” and “Executive Compensation Tables” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 7, 2014.

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

The information required by Item 12 is incorporated herein by reference to the relevant information under the captions “Security Ownership of Certain Beneficial Owners, Directors and Executive Officers” and “Equity Compensation Plans,” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 7, 2014.

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

The information required by Item 13 is incorporated herein by reference to the relevant information under the caption “Corporate Governance” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 7, 2014.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by Item 14 is incorporated herein by reference to the relevant information under the captions “Principal Accountant Fees and Services” and “Pre-Approval Policy for Independent Auditor Services” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 7, 2014.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a) Financial Statements and Schedules

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

(b) Exhibit Listing

Exhibit Number	Description
(3)	**Articles of Incorporation and Bylaws**
3.1*	Second Amended and Restated Articles of Incorporation of Portland General Electric Company (Form 10-Q filed August 3, 2009, Exhibit 3.1).
3.2*	Ninth Amended and Restated Bylaws of Portland General Electric Company (Form 8-K filed October 27, 2011, Exhibit 3.1).
(4)	**Instruments defining the rights of security holders, including indentures**
4.1*	Portland General Electric Company Indenture of Mortgage and Deed of Trust dated July 1, 1945 (Form 8, Amendment No. 1 dated June 14, 1965) (File No. 001-05532-99).
4.2*	Fortieth Supplemental Indenture dated October 1, 1990 (Form 10-K for the year ended December 31, 1990, Exhibit 4) (File No. 001-05532-99).
4.3*	Fifty-sixth Supplemental Indenture dated May 1, 2006 (Form 8-K filed May 25, 2006, Exhibit 4.1) (File No. 001-05532-99).
4.4*	Fifty-seventh Supplemental Indenture dated December 1, 2006 (Form 8-K filed December 22, 2006, Exhibit 4.1) (File No. 001-05532-99).
4.5*	Fifty-eighth Supplemental Indenture dated April 1, 2007 (Form 8-K filed April 12, 2007, Exhibit 4.1) (File No. 001-05532-99).
4.6*	Fifty-ninth Supplemental Indenture dated October 1, 2007 (Form 8-K filed October 5, 2007, Exhibit 4.1) (File No. 001-05532-99).
4.7*	Sixtieth Supplemental Indenture dated April 1, 2008 (Form 8-K filed April 17, 2008, Exhibit 4.1).
4.8*	Sixty-first Supplemental Indenture dated January 15, 2009 (Form 8-K filed January 16, 2009, Exhibit 4.1).
4.9*	Sixty-second Supplemental Indenture dated April 1, 2009 (Form 8-K filed April 16, 2009, Exhibit 4.1).
4.10*	Sixty-third Supplemental Indenture dated November 1, 2009 (Form 8-K filed November 4, 2009, Exhibit 4.1).
4.11*	Sixty-seventh Supplemental Indenture dated June 15, 2013 (Form 8-K filed June 27, 2013, Exhibit 4.1).
4.12*	Sixty-eighth Supplemental Indenture dated October 15, 2013 (Form S-3 filed November 12, 2013, Exhibit 4.13).
(10)	**Material Contracts**
10.1*	Credit Agreement dated November 14, 2012, between Portland General Electric Company, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A. and U.S. Bank National Association, as Co-Syndication Agents, and a group of lenders (Form 10-K filed February 22, 2013, Exhibit 10.1).
10.2*	Credit Agreement dated December 8, 2011, between Portland General Electric Company, Bank of America, N.A., as Administrative Agent, Barclays Capital, as Syndication Agent, and a group of lenders (Form 10-K filed February 24, 2012, Exhibit 10.3).
10.3*	First Amendment dated April 10, 2012 to Credit Agreement dated December 8, 2011, between Portland General Electric Company, Bank of America, N.A., as Administrative Agent, and a group of lenders (Form 10-K filed February 22, 2013, Exhibit 10.3).

Exhibit Number	Description
10.4*	Second Amendment dated October 31, 2012 to Credit Agreement dated December 8, 2011, between Portland General Electric Company, Bank of America, N.A., as Administrative Agent, and a group of lenders (Form 10-K filed February 22, 2013, Exhibit 10.4).
10.5*	Third Amendment dated January 7, 2013 to Credit Agreement dated December 8, 2011, between Portland General Electric Company, Bank of America, N.A., as Administrative Agent, and a group of lenders (Form 10-K filed February 22, 2013, Exhibit 10.5).
10.6*	Confirmation of Forward Sale Transaction dated June 11, 2013 between Portland General Electric Company and Barclays Bank PLC (Form 8-K filed June 17, 2013, Exhibit 10.1).
10.7*	First Amendment to Confirmation Agreement dated June 25, 2013 between Portland General Electric Company and Barclays Bank PLC (Form 10-Q filed August 2, 2013, Exhibit 10.2).
10.8	Transfer Agreement between BA Leasing BSC, LLC, as Transferor, and Portland General Electric Company, as Transferee, dated December 18, 2013.
10.9*	Portland General Electric Company Severance Pay Plan for Executive Employees dated June 15, 2005 (Form 8-K filed June 20, 2005, Exhibit 10.1) (File No. 001-05532-99). +
10.10*	Portland General Electric Company Outplacement Assistance Plan dated June 15, 2005 (Form 8-K filed June 20, 2005, Exhibit 10.2) (File No. 001-05532-99). +
10.11*	Portland General Electric Company 2005 Management Deferred Compensation Plan dated January 1, 2005 (Form 10-K filed March 11, 2005, Exhibit 10.18) (File No. 001-05532-99). +
10.12*	Portland General Electric Company Management Deferred Compensation Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.1) (File No. 001-05532-99). +
10.13*	Portland General Electric Company Supplemental Executive Retirement Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.2) (File No. 001-05532-99). +
10.14*	Portland General Electric Company Senior Officers' Life Insurance Benefit Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.3) (File No. 001-05532-99). +
10.15*	Portland General Electric Company Umbrella Trust for Management dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.4) (File No. 001-05532-99). +
10.16*	Portland General Electric Company 2006 Stock Incentive Plan, as amended (Form 10-K filed February 27, 2008, Exhibit 10.23). +
10.17*	Portland General Electric Company 2006 Annual Cash Incentive Master Plan (Form 8-K filed March 17, 2006, Exhibit 10.1) (File No. 001-05532-99). +
10.18*	Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan (Form 8-K filed May 17, 2006, Exhibit 10.1) (File No. 001-05532-99). +
10.19*	Portland General Electric Company 2008 Annual Cash Incentive Master Plan for Executive Officers (Form 8-K filed February 26, 2008, Exhibit 10.1). +
10.20*	Form of Portland General Electric Company Agreement Concerning Indemnification and Related Matters (Form 8-K filed December 24, 2009, Exhibit 10.1). +
10.21*	Form of Portland General Electric Company Agreement Concerning Indemnification and Related Matters for Officers and Key Employees (Form 8-K filed February 19, 2010, Exhibit 10.1). +
10.22*	Form of Directors' Restricted Stock Unit Agreement (Form 8-K filed July 14, 2006, Exhibit 10.1) (File No. 001-05532-99). +
10.23*	Form of Officers' and Key Employees' Performance Stock Unit Agreement (Form 10-Q filed May 3, 2012, Exhibit 10.1). +
10.24*	Employment Agreement dated and effective May 6, 2008 between Stephen M. Quennoz and Portland General Electric Company (Form 10-Q filed May 7, 2008, Exhibit 10.3). +
(12)	**Statements Re Computation of Ratios**
12.1	Computation of Ratio of Earnings to Fixed Charges.
(23)	**Consents of Experts and Counsel**
23.1	Consent of Independent Registered Public Accounting Firm Deloitte & Touche LLP.
(31)	**Rule 13a-14(a)/15d-14(a) Certifications**
31.1	Certification of Chief Executive Officer.
31.2	Certification of Chief Financial Officer.
(32)	**Section 1350 Certifications**
32.1	Certifications of Chief Executive Officer and Chief Financial Officer.

Exhibit Number	Description
(101)	**Interactive Data File**
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

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* Incorporated by reference as indicated.
\+ Indicates a management contract or compensatory plan or arrangement.

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

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on February 13, 2014.

PORTLAND GENERAL ELECTRIC COMPANY

By: /s/ JAMES J. PIRO

James J. Piro

President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on February 13, 2014.

Signature	Title
/s/ JAMES J. PIRO **James J. Piro**	*President, Chief Executive Officer, and Director* (principal executive officer)
/s/ JAMES F. LOBDELL **James F. Lobdell**	*Senior Vice President of Finance, Chief Financial Officer, and Treasurer* (principal financial and accounting officer)
/s/ JOHN W. BALLANTINE **John W. Ballantine**	*Director*
/s/ RODNEY L. BROWN, JR. **Rodney L. Brown, Jr.**	*Director*
/s/ JACK E. DAVIS **Jack E. Davis**	*Director*
/s/ DAVID A. DIETZLER **David A. Dietzler**	*Director*
/s/ KIRBY A. DYESS **Kirby A. Dyess**	*Director*
/s/ MARK B. GANZ **Mark B. Ganz**	*Director*
/s/ NEIL J. NELSON **Neil J. Nelson**	*Director*
/s/ M. LEE PELTON **M. Lee Pelton**	*Director*

EXHIBIT 31.1

CERTIFICATION

I, James J. Piro, certify that:

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

Date: February 13, 2014

/s/ JAMES J. PIRO

James J. Piro

President and

Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, James F. Lobdell, certify that:

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

Date: February 13, 2014

/s/ JAMES F. LOBDELL

James F. Lobdell

Senior Vice President of Finance, Chief Financial Officer, and Treasurer

EXHIBIT 32.1

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

We, James J. Piro, President and Chief Executive Officer, and James F. Lobdell, Senior Vice President of Finance, Chief Financial Officer and Treasurer, of Portland General Electric Company (the “Company”), hereby certify that the Company’s Annual Report on Form 10-K for the year ended December 31, 2013, as filed with the Securities and Exchange Commission on February 14, 2014 pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the “Report”), fully complies with the requirements of that section.

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

/s/ JAMES J. PIRO
James J. Piro
President and
Chief Executive Officer

Date: February 13, 2014

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

Date: February 13, 2014

2013 Accomplishments | The year was marked by many accomplishments for Portland General Electric. Here are a few of the highlights.

$105 million
Net income for the year

No.1 Rank for the number of renewable power customers and renewable energy sales in the nation

89.4% PGE's generating plant availability[1]

$1.25 billion
Planned investments in three new generation plants

836,070
Customers served as of Dec. 31

High customer satisfaction
Top quartile ranking for residential customers[2]; Top decile ranking for general business customers[2]; and No. 4 nationally for large key customers[3]

$1.6 million Amount contributed by employees and company match to the community through PGE's employee giving campaign

$447 million Debt and equity raised in 2013 to finance new projects, provide working capital and pay off other debt

80,000 safer students
PGE delivered safety presentations to K-6 students in the classroom and community

Readiness Center Facility now sits ready to support critical functions in extreme emergencies

1: Excludes Colstrip plant | 2. Market Strategies International 2013 Electric Utility Satisfaction Study | 3. TQS Research 2013 survey

Corporate Information

Board of Directors

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

James J. Piro
President and Chief Executive Officer,
Portland General Electric

John W. Ballantine
Retired Executive Vice President
and Chief Risk Management Officer,
First Chicago NBD Corporation

Rodney L. Brown, Jr.
Managing Partner,
Cascadia Law Group PLLC

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

Kirby A. Dyess
Principal,
Austin Capital Management LLC

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

Neil J. Nelson
President and Chief Executive Officer,
Siltronic Corporation

M. Lee Pelton
President, Emerson College

Charles W. Shivery
Retired Chairman, President and Chief
Executive Officer, Northeast Utilities

Kathryn J. Jackson*
Chief Technology Officer and Senior Vice
President of Research and Technology,
Westinghouse Electric Company LLC

*Appointed to the Board of Directors effective as of April 26, 2014

Corporate Officers

James J. Piro
President and Chief Executive Officer

James F. Lobdell
Senior Vice President, Finance,
Chief Financial Officer and Treasurer

William O. Nicholson
Senior Vice President,
Customer Service, Transmission and
Distribution

Maria M. Pope
Senior Vice President, Power Supply and
Operations, and Resource Strategy

Arleen N. Barnett
Vice President, Human Resources,
Diversity and Inclusion, and Administration

O. Bruce Carpenter
Vice President, Distribution

Carol A. Dillin
Vice President, Customer Strategies and
Business Development

J. Jeffrey Dudley
Vice President, General Counsel,
Corporate Compliance Officer and
Assistant Secretary

Campbell A. Henderson
Vice President, Information Technology
and Chief Information Officer

Stephen M. Quennoz
Vice President, Nuclear and Power
Supply / Generation

W. David Robertson
Vice President, Public Policy

Kristin Stathis
Vice President, Customer Service
Operations

Investor Information

Corporate Headquarters
Portland General Electric Company
121 SW Salmon Street
Portland, Oregon 97204
503.464.8000
Investors.PortlandGeneral.com

Transfer Agent
American Stock
Transfer & Trust Company
59 Maiden Lane
Plaza Level
New York, NY 10038
866.621.2788

Independent Auditors
Deloitte & Touche LLP
3900 U.S. Bancorp Tower
111 SW Fifth Avenue
Portland, Oregon 97204
503.222.1341

Form 10-K
A copy of the company's 2013 Annual Report on Form 10-K will be furnished, without charge, upon written request made to:

William Valach
Director, Investor Relations
121 SW Salmon Street
1WTC0509
Portland, Oregon 97204

You may also obtain a copy of the Form 10-K by calling Investor Relations at 503.464.8586 or by downloading a copy from the company's website at *Investors.PortlandGeneral.com.*

Market Information
Portland General Electric Company common stock trades on the New York Stock Exchange under the ticker symbol POR.

To vote online visit:
Investors.PortlandGeneral.com

IMAGES:

On cover, left to right:
Robert Thompson, Leadman Repairman;
Biglow Canyon Wind Farm;
Construction at Port Westward Unit 2;
Kevin Whitener, Engineer, Salem Smart Power Center

Inside shareholder letter (left):
Jim Piro, President and Chief Executive Officer;
Faraday Powerhouse, new penstocks

Inside shareholder letter (right):
Mathew Quigley, Engineer, Port Westward Unit 2

Inside 2013 Accomplishments, left to right:
Rosa Sambrano, Journeyman Meterman;
PGE crews doing restoration work

Back cover, left to right:
Larisa Seibel, Customer Service Representative;
Rodante Baysa, Financial Analyst, Volunteer

Portland General Electric

Corporate Headquarters
121 SW Salmon Street | Portland, Oregon 97204
PortlandGeneral.com