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SAP AKTIENGESELLSCHAFT SYSTEMS APPLICATIONS PRODUCTS IN DATA

Form 6-K

July 09, 2004

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**UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION**

**Washington, D.C. 20549**

**FORM 6-K**

REPORT OF FOREIGN PRIVATE ISSUER  
PURSUANT TO RULE 13a-16 OR 15d-16 OF  
THE SECURITIES EXCHANGE ACT OF 1934

July 9, 2004

Commission file number:

1-14251

SAP AKTIENGESELLSCHAFT  
SYSTEME, ANWENDUNGEN, PRODUKTE IN DER DATENVERARBEITUNG

(Exact name of registrant as specified in its charter)

SAP CORPORATION  
SYSTEMS, APPLICATIONS AND PRODUCTS IN DATA PROCESSING

(Translation of registrant's name into English)

Neurottstrasse 16  
69190 Walldorf  
Federal Republic of Germany  
(Address of principal executive offices)

Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20-F or Form 40-F.

Form 20-F

Form 40-F

Indicate by check mark whether the registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes

No

If Yes is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): 82-  
\_\_\_\_\_.

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**SIGNATURES**

EXhibit 99.1

SAP AKTIENGESELLSCHAFT  
SYSTEME, ANWENDUNGEN, PRODUKTE IN DER DATENVERARBEITUNG

FORM 6-K

On July 9, 2004, SAP Aktiengesellschaft Systeme, Anwendungen, Produkte in der Datenverarbeitung, a stock corporation organized under the laws of the Federal Republic of Germany ( SAP ), issued a press release (the Press Release ) pre-announcing SAP s financial results for the second quarter ended June 30, 2004. The Press Release is attached as Exhibit 99.1 hereto and incorporated by reference herein.

The press release discloses pro forma operating income, which is considered a non-GAAP financial measure. Generally, a non-GAAP financial measure is a numerical measure of a company s performance, financial position, or cash flows that either excludes or includes amounts that are not normally excluded or included in the most directly comparable measure calculated and presented in accordance with GAAP. Pro forma operating income excludes acquisition related charges and settlements of stock-based compensation plans as well as stock-based compensation expenses. Management believes that this pro forma measure provides supplemental meaningful information to the investor to fully assess our financial performance of the core operations. Management excludes stock-based compensation expenses because we have no direct influence over the actual expense of these awards once we enter into Stock-Based Compensation Plans. However this measure should be considered in addition to, and not as a substitute for, or superior to, operating income, or other measures of financial performance prepared in accordance with GAAP.

As used herein, GAAP refers to generally accepted accounting principles in the United States.

Any statements contained in this document that are not historical facts are forward-looking statements as defined in the U.S. Private Securities Litigation Reform Act of 1995. Words such as anticipate, believe, estimate, expect, forecast, intend, may, plan, project, predict, should and will and similar expressions as they relate to SA to identify such forward-looking statements. SAP undertakes no obligation to publicly update or revise any forward-looking statements. All forward-looking statements are subject to various risks and uncertainties that could cause actual results to differ materially from expectations. The factors that could affect SAP s future financial results are discussed more fully in SAP s filings with the U.S. Securities and Exchange Commission (the SEC ), including SAP s most recent Annual Report on Form 20-F for 2003 filed with the SEC. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of their dates.

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EXHIBITS

<b><u>Exhibit No.</u></b>	<b><u>Exhibit</u></b>
99.1	Press Release dated July 9, 2004

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SIGNATURES

Pursuant to the requirements 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.

SAP AKTIENGESELLSCHAFT SYSTEME,  
ANWENDUNGEN, PRODUKTE IN DER  
DATENVERARBEITUNG  
(Registrant)

By: /s/ Henning Kagermann  
Name: Prof. Dr. Henning Kagermann  
Title: Chairman and CEO

By: /s/ Werner Brandt  
Name: Dr. Werner Brandt  
Title: CFO

Date: July 9, 2004

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<u>Exhibit No.</u>	<u>Exhibit</u>
99.1	(i) Press Release dated July 9, 2004

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dding-top:2px;padding-bottom:2px;padding-right:2px;border-top:1px solid #000000;">

Noncurrent

Current

Noncurrent

Regulatory assets:

Price risk management

\$  
40

\$  
76

\$  
36

\$  
140

Pension and other postretirement plans

—

180

—

194

Deferred income taxes

—

85

—

76

Deferred broker settlements

4

—

12

1

Debt reacquisition costs

—

16

—

17

Deferred capital projects

4

19

16

18

Other

8

20

2

18

Total regulatory assets

\$

56

\$

396

\$

66

\$

464

Regulatory liabilities:

Asset retirement removal costs

\$

—

\$

791

\$

—

\$



747

Trojan decommissioning activities

—

57

—

41

Asset retirement obligations

—

40

—

39

Other

4

52

1

38

Total regulatory liabilities

\$

4

\*

\$

940

\$

1

\*

\$  
865

\*Included in Accrued expenses and other current liabilities in the condensed consolidated balance sheets.

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## PORTLAND GENERAL ELECTRIC COMPANY

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued

(Unaudited)

## Accrued Expenses and Other Current Liabilities

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

	September 30, 2014	December 31, 2013
Accrued employee compensation and benefits	\$50	\$46
Accrued interest payable	37	23
Accrued taxes payable	37	21
Accrued dividends payable	23	22
Regulatory liabilities—current	4	1
Other	60	58
Total accrued expenses and other current liabilities	\$211	\$171

## Credit Facilities

PGE has the following unsecured revolving credit facilities as of September 30, 2014:

▲ \$400 million syndicated credit facility, which is scheduled to expire in November 2018; and

▲ \$300 million syndicated credit facility, which is scheduled to expire 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 provisions for two, one-year extensions that are 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 agreements, to 65% of total capitalization. As of September 30, 2014, PGE was in compliance with this covenant with a 55.1% debt to total capital ratio.

PGE 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 Federal Energy Regulatory Commission (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.

PGE classifies borrowings under the revolving credit facilities and outstanding commercial paper as Short-term debt on the condensed consolidated balance sheets. As of September 30, 2014, PGE had no borrowings outstanding under the revolving credit facilities, no commercial paper outstanding, and \$9 million of letters of credit issued. As of September 30, 2014, the aggregate available capacity under the credit facilities was \$691 million.

In addition, the Company has two \$30 million letter of credit facilities, under which PGE can request letters of credit for original terms not to exceed one year. The issuance of such letters of credit are subject to the approval of the issuing institution. As of September 30, 2014, \$55 million of letters of credit had been issued under these facilities.



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## PORTLAND GENERAL ELECTRIC COMPANY

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued

(Unaudited)

## Long-term Debt

During the nine months ended September 30, 2014, PGE obtained four term loans pursuant to a credit agreement in an aggregate principal amount of \$305 million. The term loan interest rates are set at the beginning of the interest period for periods ranging from one- to six-months, as selected by PGE and are based on the London Interbank Offered Rate (LIBOR) plus 70 basis points (approximately 0.9% as of September 30, 2014), with no other fees. The credit agreement expires October 30, 2015, at which time any amounts outstanding under the term loans become due and payable. Upon the occurrence of certain events of default, the Company's obligations under the credit agreement may be accelerated. Such events of default include payment defaults to lenders under the credit agreement, covenant defaults and other customary defaults.

Additionally, in May 2014, PGE entered into a bond purchase agreement with certain institutional buyers (Buyers) under which the Company agreed to sell to the Buyers, in three tranches, an aggregate principal amount of \$280 million of First Mortgage Bonds (FMBs). During the third quarter of 2014, 4.39% Series FMBs, due 2045, in the amount of \$100 million was issued and funded. On October 15, 2014, a 4.44% Series FMBs, due 2046, in the amount of \$100 million was issued and funded. A 3.51% Series FMBs, due 2024, in the amount of \$80 million is expected to be issued and funded on or about November 17, 2014.

## Pension and Other Postretirement Benefits

Components of net periodic benefit cost are as follows (in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2014	2013	2014	2013	2014	2013
Three Months Ended September 30:						
Service cost	\$4	\$4	\$—	\$1	\$—	\$—
Interest cost	8	7	1	1	—	—
Expected return on plan assets	(9	) (10	) —	—	—	—
Amortization of net actuarial loss	4	6	—	—	—	—
Net periodic benefit cost	\$7	\$7	\$1	\$2	\$—	\$—
Nine Months Ended September 30:						
Service cost	\$11	\$12	\$1	\$2	\$—	\$—
Interest cost	25	23	3	3	1	1
Expected return on plan assets	(29	) (30	) (1	) (1	) —	—
Amortization of prior service cost	—	—	1	1	—	—
Amortization of net actuarial loss	13	18	—	—	—	—
Net periodic benefit cost	\$20	\$23	\$4	\$5	\$1	\$1

## NOTE 3: 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 condensed consolidated balance sheets, for which it is practicable to estimate fair value as of September 30, 2014 and December 31, 2013, 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 levels and application to the Company are discussed below.



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## PORTLAND GENERAL ELECTRIC COMPANY

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued

(Unaudited)

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 that are unobservable for the asset or liability.

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

PGE recognizes transfers between levels in the fair value hierarchy as of the end of the reporting period for all 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 three and nine month periods ended September 30, 2014 and 2013, 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 September 30, 2014			Total
	Level 1	Level 2	Level 3	
Assets:				
Nuclear decommissioning trust: <sup>(1)</sup>				
Money market funds	\$—	\$65	\$—	\$65
Debt securities:				
Domestic government	8	6	—	14
Corporate credit	—	10	—	10
Non-qualified benefit plan trust: <sup>(2)</sup>				
Equity Securities:				
Domestic	4	2	—	6
International	1	—	—	1
Assets from price risk management activities: <sup>(1)(3)</sup>				
Electricity	—	2	—	2
Natural gas	—	3	1	4
	\$13	\$88	\$1	\$102
Liabilities—Liabilities from price risk management activities: <sup>(1)(3)</sup>				
Electricity	\$—	\$4	\$80	\$84
Natural gas	—	19	19	38
	\$—	\$23	\$99	\$122

(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 4, Price Risk Management.





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## PORTLAND GENERAL ELECTRIC COMPANY

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued

(Unaudited)

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

<sup>(1)</sup> 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.

<sup>(2)</sup> Excludes insurance policies of \$26 million, which are recorded at cash surrender value.

<sup>(3)</sup> For further information, see Note 4, Price Risk Management.

Trust assets held in the Nuclear decommissioning and Non-qualified benefit plan trusts are recorded at fair value in PGE's condensed 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

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considered in the valuation as applicable.

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PORTLAND GENERAL ELECTRIC COMPANY

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued

(Unaudited)

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. 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 condensed 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 variable power costs (NVPC) for the Company's retail customers. For additional information regarding these assets and liabilities, see Note 4, 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 consist of forwards, futures and swaps.

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

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## PORTLAND GENERAL ELECTRIC COMPANY

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued

(Unaudited)

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		Valuation Technique	Significant Unobservable Input	Price per Unit		Weighted Average
	Assets	Liabilities			Low	High	
As of September 30, 2014:							
Electricity physical forward	\$—	\$65	Discounted cash flow	Electricity forward price (per MWh)	\$12.91	\$110.96	\$41.50
Natural gas financial swaps	1	19	Discounted cash flow	Natural gas forward price (per Decatherm)	3.30	4.99	3.86
Electricity financial futures	—	15	Discounted cash flow	Electricity forward price (per MWh)	12.91	43.34	35.72
	\$1	\$99					
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 Decatherm)	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					

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

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## PORTLAND GENERAL ELECTRIC COMPANY

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued

(Unaudited)

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):

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2014	2013	2014	2013
Balance as of the beginning of the period	\$89	\$56	\$139	\$16
Net realized and unrealized losses (gains)*	9	8	(45	) 48
Settlements	(1	) —	(1	) —
Transfers out of Level 3 to Level 2	1	—	5	—
Balance as of the end of the period	\$98	\$64	\$98	\$64

Contains nominal amounts of realized losses. Both realized and unrealized losses (gains) are recorded in Purchased \*power and fuel expense in the condensed consolidated statements of income of which the unrealized portion is fully offset by the effects of regulatory accounting until settlement of the underlying transactions.

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 three and nine month periods ended September 30, 2014 and 2013, 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 condensed consolidated balance sheets. The fair value of the Company's FMBs and Pollution Control Bonds 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. The fair value of PGE's unsecured term bank loans is classified as Level 3 fair value measurement and is estimated based on the terms of the loans and the Company's creditworthiness. These significant unobservable inputs to the Level 3 fair value measurement include the interest rate and the length of the loan. The estimated fair value of the Company's unsecured term bank loans approximates their carrying value.

As of September 30, 2014, the carrying amount of PGE's long-term debt was \$2,321 million and its estimated aggregate fair value was \$2,632 million, consisting of \$2,327 million and \$305 million classified as Level 2 and Level 3, respectively, in the fair value hierarchy. As of December 31, 2013, the carrying amount of PGE's long-term debt was \$1,916 million and its estimated aggregate fair value was \$2,074 million, all classified as Level 2 in the fair value hierarchy.

## NOTE 4: PRICE RISK MANAGEMENT

PGE participates in the wholesale marketplace in order to balance its supply of power, which consists of its own generation combined with wholesale market transactions, to meet the needs of its retail customers, manage risk, and administer its existing long-term wholesale contracts. Such activities include fuel and power purchases and sales

resulting from economic dispatch decisions for Company-owned generation. As a result, PGE is exposed to commodity price risk and foreign currency exchange rate risk, from which changes in prices and/or rates may affect the Company's financial position, results of operations, or cash flows.

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## PORTLAND GENERAL ELECTRIC COMPANY

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued

(Unaudited)

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

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

	September 30, 2014		December 31, 2013	
Current assets:				
Commodity contracts:				
Electricity	\$2		\$9	
Natural gas	2		4	
Total current derivative assets	4	(1)	13	(1)
Noncurrent assets:				
Commodity contracts:				
Electricity	—		1	
Natural gas	2		—	
Total noncurrent derivative assets	2	(2)	1	(2)
Total derivative assets not designated as hedging instruments	\$6		\$14	
Total derivative assets	\$6		\$14	
Current liabilities:				
Commodity contracts:				
Electricity	\$29		\$20	
Natural gas	15		29	
Total current derivative liabilities	44		49	
Noncurrent liabilities:				
Commodity contracts:				
Electricity	55		107	
Natural gas	23		34	
Total noncurrent derivative liabilities	78		141	
Total derivative liabilities not designated as hedging instruments	\$122		\$190	
Total derivative liabilities	\$122		\$190	

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

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



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## PORTLAND GENERAL ELECTRIC COMPANY

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued

(Unaudited)

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 through 2035, were as follows (in millions):

	September 30, 2014		December 31, 2013	
Commodity contracts:				
Electricity	18	MWh	14	MWh
Natural gas	100	Decatherms	106	Decatherms
Foreign currency	\$8	Canadian	\$7	Canadian

PGE has elected to report gross on the condensed 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 presented 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 <sup>(1)</sup>	
As of September 30, 2014:						
Liabilities:						
Commodity contracts:						
Electricity <sup>(2)</sup>	\$ 52	\$—	\$52	\$(52)	) \$—	\$—
Natural gas <sup>(2)</sup>	1	—	1	(1)	) —	—
	\$ 53	\$—	\$53	\$(53)	) \$—	\$—
As of December 31, 2013:						
Liabilities:						
Commodity contracts:						
Electricity <sup>(2)</sup>	\$ 91	\$—	\$91	\$(91)	) \$—	\$—
Natural gas <sup>(2)</sup>	1	—	1	(1)	) —	—
	\$ 92	\$—	\$92	\$(92)	) \$—	\$—

(1) As of September 30, 2014 and December 31, 2013, PGE had posted collateral in the amount of \$9 million and \$7 million, respectively, which consisted entirely of letters of credit.

(2) Included in Liabilities from price risk management activities—current and Liabilities from price risk management activities—noncurrent.

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## PORTLAND GENERAL ELECTRIC COMPANY

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued

(Unaudited)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Commodity contracts:				
Electricity	\$8	\$(1	) \$(21	) \$17
Natural Gas	25	10	(17	) 30

Net unrealized and certain net realized losses (gains) presented in the preceding table are offset within the condensed consolidated statements of income by the effects of regulatory accounting. Of the net losses (gains) recognized in Net income for the three months ended September 30, 2014 and 2013, net losses of \$34 million and \$7 million, respectively, have been offset. Net gains of \$30 million and net losses of \$66 million have been offset for the nine months ended September 30, 2014 and 2013, respectively.

Assuming no changes in market prices and interest rates, the following table indicates the year in which the net unrealized loss recorded as of September 30, 2014 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2014	2015	2016	2017	2018	Thereafter	Total
Commodity contracts:							
Electricity	\$4	\$28	\$13	\$5	\$4	\$28	\$82
Natural gas	6	10	12	5	1	—	34
Net unrealized loss	\$10	\$38	\$25	\$10	\$5	\$28	\$116

PGE's secured and unsecured debt is currently rated at investment grade by Moody's Investors Service (Moody's) and Standard and Poor's Ratings Services (S&P). Should Moody's and/or 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, in the form of cash or letters of credit, based on total portfolio positions with each of those counterparties. Certain other counterparties would have the right to terminate their agreements with the Company.

The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position as of September 30, 2014 was \$119 million, for which PGE has posted \$17 million in collateral, consisting primarily of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at September 30, 2014, the cash requirement to either post as collateral or settle the instruments immediately would have been \$116 million. As of September 30, 2014, PGE has posted an immaterial amount of cash collateral, which is classified as Margin deposits included in Other current assets on the Company's condensed consolidated balance sheet, for derivative instruments with no credit-risk related contingent features.

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## PORTLAND GENERAL ELECTRIC COMPANY

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued

(Unaudited)

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

	September 30, 2014	December 31, 2013		
Assets from price risk management activities:				
Counterparty A	37	% 53		%
Counterparty B	20	5		
Counterparty C	11	—		
	68	% 58		%
Liabilities from price risk management activities:				
Counterparty D	39	% 43		%
Counterparty E	15	11		
	54	% 54		%

See Note 3, Fair Value of Financial Instruments, for additional information concerning the determination of fair value for the Company's Assets and Liabilities from price risk management activities.

## NOTE 5: EARNINGS PER SHARE

Basic earnings per share is computed based on the weighted average number of common shares outstanding during the period. 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 period 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 an equity forward sale agreement (EFSA). See Note 6, Equity, 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 have been met. For the three and nine month periods ended September 30, 2014, unvested performance-based restricted stock units and associated dividend equivalent rights of approximately 361,000 were excluded from the dilutive calculation because the performance goals had not been met. For the three and nine month periods ended September 30, 2013, unvested performance-based restricted stock units and associated dividend equivalent rights of approximately 440,000 were similarly excluded.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Weighted-average common shares outstanding—basic	78,203	77,637	78,170	76,401
Dilutive effect of potential common shares	2,022	693	1,807	302
Weighted-average common shares outstanding—diluted	80,225	78,330	79,977	76,703

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## PORTLAND GENERAL ELECTRIC COMPANY

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued

(Unaudited)

## NOTE 6: EQUITY

The activity in equity during the nine months ended September 30, 2014 and 2013 is as follows (dollars in millions):

	Portland General Electric Company Shareholders' Equity				
	Common Stock		Accumulated Other Comprehensive Loss	Retained Earnings	Noncontrolling Interests' Equity
	Shares	Amount			
Balances as of December 31, 2013	78,085,559	\$911	\$(5	) \$913	\$1
Issuances of shares pursuant to equity-based plans	123,869	1	—	—	—
Stock-based compensation	—	4	—	—	—
Dividends declared	—	—	—	(67	) —
Net income	—	—	—	132	(1
Balances as of September 30, 2014	78,209,428	\$916	\$(5	) \$978	\$—
Balances 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	—	—	—
Issuances of shares pursuant to equity-based plans	146,027	—	—	—	—
Stock-based compensation	—	2	—	—	—
Dividends declared	—	—	—	(63	) —
Net income (loss)	—	—	—	58	(1
Balances as of September 30, 2013	78,067,299	\$910	\$(6	) \$888	\$1

In connection with a public offering of shares of its common stock in 2013, PGE entered into an 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: i) physical; ii) cash; or iii) 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 is 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

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of the common stock. PGE concluded that the EFSA was an equity instrument and that it does not qualify as a

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PORTLAND GENERAL ELECTRIC COMPANY

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued

(Unaudited)

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 September 30, 2014, the Company could have physically settled the EFSA by delivering 10,400,000 shares to the forward counterparty in exchange for cash of \$278 million. In addition, at September 30, 2014, the Company could have elected to make a cash settlement by paying approximately \$56 million, or a net share settlement by delivering approximately 1,742,421 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 are 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 are 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).

NOTE 7: CONTINGENCIES

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

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

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

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

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 are a wide range of potential outcomes. In such cases, there is considerable

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uncertainty regarding the timing or ultimate resolution, including any possible loss, fine, penalty, or business impact.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued

(Unaudited)

Trojan Investment Recovery

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

Numerous challenges and appeals were subsequently filed in various state courts on the issue of the OPUC's authority under Oregon law to grant recovery of, and a return on, the Trojan investment. In 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.

On October 2, 2014, the Oregon Supreme Court, in a unanimous decision, affirmed the February 6, 2013 Oregon Court of Appeals decision that upheld the OPUC's 2008 Order.

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.

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PORTLAND GENERAL ELECTRIC COMPANY

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued

(Unaudited)

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.

The October 2, 2014 Oregon Supreme Court decision described above expressly noted that the plaintiffs in the class action must address any request to lift the abatement with the Marion County Circuit Court. PGE is evaluating how to proceed with respect to the class actions.

Because the class actions remain pending, management believes that it is reasonably possible that a loss to the Company in excess of the amounts previously recorded and discussed above could result. As these matters involve unsettled legal theories and have a broad range of potential outcomes, sufficient information is currently not available to determine 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. Upon appeal of the decision to the U.S. Ninth Circuit Court of Appeals (Ninth Circuit) the Court remanded the case to the FERC to, among other things, address market manipulation evidence in detail and account for the evidence in any future orders regarding the award or denial of refunds in the proceedings.

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.

In December 2012, the FERC issued an order clarifying 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, the FERC granted rehearing of its Order on Remand 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.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued

(Unaudited)

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 the California Energy Resource Scheduling division of the California Department of Water Resources (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 first phase of the 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 a subsequent phase of the proceeding if refunds are ordered against some or all of the current respondents.

During the first phase of the remand hearing, now completed, two sets of refund proponents, the City of Seattle, Washington (Seattle) and various California parties on behalf of CERS, presented cases alleging that multiple respondents had engaged in unlawful activities and caused severe financial harm that justified the imposition of refunds. After conclusion of the hearing, the presiding Administrative Law Judge issued an Initial Decision on March 28, 2014 finding: i) that Seattle did not carry its Mobile-Sierra burden with respect to its refund claims against any of its respondent sellers; and ii) that the California representatives of CERS did not carry their Mobile-Sierra burden with respect to one of CERS' respondents, but did find evidence of unlawful activity in the implementation of multiple transactions and bad faith in the formation of as many as 119 contracts by the last remaining CERS respondent. The Administrative Law Judge scheduled a second phase of the hearing to commence after a final FERC decision on the Initial Decision. In the second phase, the last respondent will have an opportunity to produce additional evidence as to why its transactions should be considered legitimate and why refunds should not be ordered. If the FERC requires one or more respondents to make refunds, it is possible that such respondent(s) will attempt to recover similar refunds from their suppliers, including the Company.

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 from any of the current respondents, which contracts would be subject to refunds, the basis on which refunds would be ordered, or how such refunds, if any, would be calculated. Further, management cannot predict whether any current respondents, if ordered to make refunds, will pursue additional refund claims against their suppliers, and, if so, what the basis or amounts of such potential refund claims against the Company would be. 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.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued

(Unaudited)

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 not expected to issue before 2017.

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, was submitted to the DEQ in February 2014. Following the DEQ's evaluation of the draft feasibility study, PGE submitted a final feasibility study to the DEQ in September 2014. The estimated costs in the final feasibility study did not differ significantly from those in the draft feasibility study. Using the Company's best estimate of the probable cost for the remediation effort from the set of alternatives provided in the feasibility study report, PGE has a \$3 million reserve for this matter as of September 30, 2014.

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 has a regulatory asset of \$3 million for future recovery in prices as of September 30, 2014. The Company included recovery of the regulatory asset in its 2015 General Rate Case filed with the OPUC in February 2014. The Company has entered into a stipulation in the 2015 GRC, which is subject to OPUC approval, that includes revenues to offset the amortization of the regulatory asset over a two year period beginning January 1, 2015.

#### 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



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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued

(Unaudited)

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 39 claims alleged in the complaint. In September 2013, the plaintiffs filed a motion for partial summary judgment regarding the appropriate method of calculating emission increases. Also in September 2013, the plaintiffs filed an amended complaint that withdrew Title V and opacity claims, added claims associated with two 2011 projects, and expanded the scope of certain claims to encompass approximately forty additional projects. In July 2014, the court denied both the defendants' motion to dismiss and the plaintiffs' motion for partial summary judgment.

On August 27, 2014, the plaintiffs filed a second amended complaint to which the defendants' response was filed September 26, 2014. The second amended complaint continues to seek injunctive relief, declaratory relief, and civil penalties for alleged violations of the federal Clean Air Act. The plaintiffs state in the second amended complaint that it was filed, in part, to comply with the court's ruling on the defendants' motion to dismiss and plaintiffs' motion for partial summary judgment. Discovery in this matter is ongoing with trial now scheduled for August 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 (collectively, the Petitioners). 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. MDEQ and the operator of CSES filed a motion to dismiss several of the claims brought by the Petitioners. On September 30, 2014, the district court denied the motion.



In October 2012, Earthjustice, on behalf of the Petitioners, filed with the Montana state district court a separate action petitioning 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

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(Unaudited)

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. It is uncertain whether the ruling will be upheld. Oral argument occurred in May 2014 and the parties now await a Court decision.

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. During the third quarter of 2013, the Company entered into a closing agreement with the DOR, under which the DOR agreed to the tax apportionment methodology utilized on the tax returns relating to open tax years 2008 through 2012.

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.

Other Matters

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

NOTE 8: 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 September 30, 2014, 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 condensed consolidated balance sheets with respect to these indemnities.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Forward-Looking Statements

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

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Forward-looking statements are not guarantees of future performance and involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed. PGE's expectations, beliefs and projections are expressed in good faith and are believed by 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 7, Contingencies, in the Notes to the Condensed Consolidated Financial Statements;

- 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;

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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;

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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

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide an understanding of the business environment, results of operations, and financial condition of PGE. MD&A should be read in conjunction with the Company's condensed consolidated financial statements contained in this report, as well as the consolidated financial statements and disclosures in its Annual Report on Form 10-K for the year ended December 31, 2013, and other periodic and current reports filed with the SEC.

Capital Requirements and Financing—Pursuant to PGE's latest acknowledged Integrated Resource Plan (IRP), PGE is in the process of constructing the following three new generation resources:

Port Westward Unit 2 (PW2)—Construction commenced in May 2013 on PW2, which is a 220 MW natural gas-fired flexible capacity resource located adjacent to the Port Westward and Beaver natural gas-fired generating plants near Clatskanie, Oregon. This project is currently on budget at an estimated total cost of \$300 million, excluding the allowance for funds used during construction (AFDC), and is expected to be online in the first quarter of 2015. As of

September 30, 2014, \$254 million, including \$16 million of AFDC, is included in CWIP for PW2. The Company has requested in its 2015 General Rate Case (2015 GRC) that cost recovery for the project begin at the point at which the plant is placed into service;

Tucannon River wind farm (Tucannon River)—Construction commenced in September 2013 on Tucannon River, which is a wind farm located in southeastern Washington with a nameplate capacity of 267 MW, consisting of 116 turbines each with a generating capacity of 2.3 MW. This project is currently on budget at an estimated total cost of \$500 million, excluding AFDC, and is expected to be online between December 2014 and early first quarter of 2015. As of September 30, 2014, \$484 million, including \$16 million of AFDC, is included in CWIP for Tucannon River. The Company requested recovery of costs related t

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o the project in its 2015 GRC to begin when the plant is placed into service. In addition, in March 2014, PGE submitted a renewable adjustment clause mechanism (RAC) filing to the OPUC to allow for deferral and recovery of costs to begin in 2014, if the project should come online in 2014; and

Carty Generating Station (Carty)—Construction commenced in January 2014 on Carty, which is a 440 MW natural gas-fired baseload resource located in Eastern Oregon, adjacent to Boardman. This project is currently on budget at an estimated total cost of \$450 million, excluding AFDC, and is expected to be online in mid-2016. As of September 30, 2014, \$234 million, including \$12 million of AFDC, is included in CWIP for Carty. The Company expects to file for recovery of costs related to this project in a 2016 General Rate Case (2016 GRC) that will be based on a 2016 test year.

In total, the Company's capital expenditures in 2014 are expected to approximate \$1 billion, which includes an estimated \$630 million related to the three new generation resources under construction discussed above. For additional information on the timing of expenditures for these three new generation resources, see "Capital Requirements" in the Liquidity and Capital Resources section of this Item 2.

PGE expects to fund 2014 estimated capital requirements with a combination of cash from operations, which is expected to range from \$470 million to \$500 million, and proceeds from long-term bank loans and issuances of FMBs of \$585 million. For additional information, see "Liquidity" and "Debt and Equity Financings" in the Liquidity and Capital Resources section of this Item 2.

General Rate Cases—On January 1, 2014, new customer prices went into effect pursuant to the OPUC order issued on PGE's 2014 General Rate Case (2014 GRC). The OPUC authorized a \$61 million increase in annual revenues, representing an approximate 4% overall increase in customer prices. 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 approved 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.

During the third quarter of 2014, PGE, OPUC Staff, and intervenors reached agreements that resolve all remaining matters in the Company's 2015 General Rate Case (2015 GRC). On February 13, 2014, PGE filed a 2015 GRC with the OPUC that is based on a 2015 test year. The primary driver of the 2015 GRC was to request recovery of costs related to PW2 and Tucannon River be included in customer prices when these resources become operational.



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Reflecting the impacts of stipulations reached with Staff and intervenors in connection with the 2015 GRC proceeding, the estimated net increase in annual revenues approximates \$17 million, representing about a 1% overall increase in customer prices. The stipulations include a capital structure of 50% debt and 50% equity, a return on equity of 9.68%, a cost of capital of 7.56%, and a rate base of approximately \$3.8 billion. The estimated net increase in annual revenues consists of the following (in millions):

New generating plants:		
Port Westward Unit 2	\$48	
Tucannon River wind farm	39	
Decrease in base business cost	(41	)
Customer credits*	(29	)
Annual revenue net increase	\$17	

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 Independent Spent Fuel Storage Installation (ISFSI) at Trojan. Also includes credits related to the return of ISFSI tax credits to customers and an additional Bonneville Power Administration (BPA) Regional Power Act refund to residential customers.

By November 14, 2014, the Company is expected to file a final update to forecasted power costs for 2015, which may further change the amounts presented in the preceding table.

The stipulations are subject to OPUC approval, with a final order on the 2015 GRC expected to be issued by the OPUC by mid-December 2014. New customer prices are expected to become effective in 2015, with a price decrease related to base business and customer credits effective January 1 and two price increases to be effective as the two new generating plants become operational. PW2 is expected to be placed in service in the first quarter of 2015 and Tucannon River is expected to be placed in service between December 2014 and early first quarter of 2015. Pursuant to the terms of the stipulation, a forecast of capital expenditures for PW2 of \$323 million and Tucannon River of \$525 million will be used to set customer prices. However, to the extent that actual capital expenditures are less than that used to set customer prices, the revenue requirement impact of any shortfall will be deferred for future refund to customers. In the event that actual capital expenditures exceed that used to set customer prices, there is no deferral of such incremental capital costs.

The Company expects to file a 2016 GRC with the OPUC in mid-February 2015 that will be based on a 2016 test year. The primary driver of the 2016 GRC is to request that costs related to Carty Generating Station be included in customer prices when this resource becomes operational, which is expected in mid-2016.

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

The impact of seasonal weather conditions on demand for electricity can cause the Company's revenues and income from operations to fluctuate from period to period. PGE is a winter-peaking utility that typically experiences its highest retail energy sales during the winter heating season, although a slightly lower peak occurs in the summer that generally results from air conditioning demand. Price changes and customer usage patterns, which can be affected by the economy, also have an effect on revenues while the availability and price of purchased power and fuel can affect income from operations.

Customers and Demand—Retail energy deliveries for the nine months ended September 30, 2014 increased overall 0.7% from the comparable period of 2013, with increases across all customer classes. The increase in commercial and industrial energy deliveries was driven by increased demand from the high tech industry, office buildings, and

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the government and education sectors, which was partially offset by decreased demand from a paper production customer. Energy efficiency and conservation efforts by retail customers continue to influence total energy deliveries, although the financial impacts to the Company of such efforts are largely mitigated by the decoupling mechanism.

The following table presents the average number of retail customers, and corresponding energy deliveries, by customer class, for the periods indicated and includes customers purchasing their energy from Electricity Service Suppliers (ESSs):

	Nine Months Ended September 30,				% Increase in Energy Deliveries	
	2014	2013	Average Number of Customers	Average Retail Energy Deliveries*		
Residential	734,792	5,472	727,579	5,469	0.1	%
Commercial	105,284	5,621	104,436	5,540	1.5	
Industrial	260	3,196	264	3,186	0.3	
Total	840,336	14,289	832,279	14,195	0.7	

\*In thousands of MWh.

Power Operations—To meet the energy needs of its retail customers, the Company utilizes a combination of its own generating resources and wholesale market transactions. Based on numerous factors, including plant availability, customer demand, river flows, wind conditions, and current wholesale prices, PGE makes economic dispatch decisions continuously in an effort to obtain reasonably-priced power for its retail customers. In addition, PGE's thermal generating plants require varying levels of annual maintenance, during which the respective plant is unavailable to provide power. 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. During the nine months ended September 30, 2014 and 2013, availability of the plants PGE operates approximated 92% and 90%, respectively, with the availability of Colstrip Units 3 and 4, in which the Company has a 20% ownership interest but does not operate, approximating 80% and 66%, respectively. Beginning in the third quarter of 2013, the Company experienced three unplanned plant outages with Boardman off-line for July 2013, Coyote Springs off-line for September through November 2013, and Colstrip Unit 4 off-line for July 2013 through January 2014. As a result of these unplanned plant outages, PGE incurred incremental replacement power costs of approximately \$2 million in the first quarter of 2014 and \$17 million in the second half of 2013.

During the nine months ended September 30, 2014, the Company's generating plants provided approximately 55% of its retail load requirement, compared with 54% in the nine months ended September 30, 2013. The increase in the proportion of power generated to meet the Company's retail load requirement was largely the result of the difference in the economic dispatch decisions made throughout the respective periods, as well as the unplanned plant outages of Boardman, Coyote Springs and Colstrip Unit 4.

Energy received from PGE-owned hydroelectric plants and under contracts from mid-Columbia hydroelectric projects in the nine months ended September 30, 2014 was comparable with the nine months ended September 30, 2013, and provided approximately 18% of the Company's retail load requirement for each of those periods. Energy received from these sources exceeded projected levels included in the Company's Annual Power Cost Update Tariff (AUT) by 2% for the first nine months of 2014 and 2013. Any excess in hydro generation from that projected in the AUT normally displaces power from higher cost sources, while any shortfall is normally replaced with power from higher cost sources. Energy from hydro resources is expected to approximate projected levels included in the AUT for 2014.

Energy expected to be received from PGE-owned wind generating resources (Biglow Canyon) is projected annually in the AUT. Any excess in wind generation from that projected in the AUT generally displaces power from higher

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cost sources, while any shortfall is normally replaced with power from higher cost sources. Energy received from Biglow Canyon fell short of that projected in PGE's AUT by 9% for the nine months ended September 30, 2014 and 14% for the nine months ended September 30, 2013, and provided approximately 7% of the Company's retail load requirement for the nine months ended September 30, 2014 and 2013.

Pursuant to the Company's power cost adjustment mechanism (PCAM), customer prices can be adjusted 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 for the year. NVPC consists of the cost of power purchased and fuel used to generate electricity to meet PGE's retail load requirements, as well as the cost of settled electric and natural gas financial contracts (all classified as Purchased power and fuel expense in the Company's condensed consolidated statements of income) and is net of wholesale revenues, which are classified as Revenues, net in the condensed consolidated statements of income. To the extent actual NVPC, subject to certain adjustments, 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. 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. Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Revenues in the Company's condensed consolidated statements of income, while any estimated collection from customers is recorded as a reduction in Purchased power and fuel expense. The deadband range is from \$15 million below to \$30 million above baseline NVPC.

For the nine months ended September 30, 2014, actual NVPC was approximately \$9 million below baseline NVPC. Based on forecast data, NVPC for the year ending December 31, 2014 is currently estimated to be below baseline NVPC, but within the deadband range; accordingly, no estimated collection from, or refund to, customers is expected under the PCAM for 2014.

For the nine months ended September 30, 2013, actual NVPC was approximately \$5 million below baseline NVPC. For the full year 2013, actual NVPC was \$11 million above baseline NVPC, which is within the established deadband range. Accordingly, no estimated collection from customers was recorded under the PCAM for 2013.

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

- Claims for refunds related to wholesale energy sales during 2000 - 2001 in the Pacific Northwest Refund Proceeding; and

- An investigation of environmental matters regarding Portland Harbor.

For additional information regarding the above and other matters, see Note 7, Contingencies, in the Notes to Condensed Consolidated Financial Statements.

On June 2, 2014, the EPA released a proposed rule, which it calls the "Clean Power Plan." The proposed rule is intended to result in a reduction of carbon emissions from existing power plants across all states to approximately 30 percent below 2005 levels by 2030. Under the proposed rule, each state would have to reduce the carbon intensity of its power sector on a state-wide basis by an amount specified by the EPA.

The proposed rule would establish state goals in terms of pounds of carbon dioxide emitted per MWh. The target amount was determined by the EPA's view of each state's options, including: i) making power plant efficiency upgrades; ii) shifting generation from coal-fired plants to natural gas-fired plants; iii) expanding use of zero- and low-carbon emitting generation (such as renewable energy and nuclear energy); and iv) implementing customer energy efficiency programs. The final goal would need to be met in 2030 and an interim goal for each state would need to be met on average over the 10-year period from 2020 to 2029. Under the proposed rule, states would have flexibility in designing programs to meet their emission reduction targets, including the four approaches noted

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above and any other measures the states choose to adopt (such as carbon tax and cap-and-trade) that would result in verified emission reductions.

The EPA is scheduled to finalize the proposed rule by June 1, 2015. If finalized by such date, states would have until June 30, 2016 to submit plans to implement the rule (subject to extension). The Company cannot predict whether the proposed rule will be adopted or, if adopted, i) how the states in which the Company's generation facilities are located will implement the rule or ii) the impact of the rule on the Company's operations. However, the rule, if adopted as proposed, could result in increased operating costs.

The following discussion highlights certain regulatory items that have impacted the Company's revenues, results of operations, or cash flows for the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013 or have affected retail customer prices, as authorized by the OPUC. In some cases, the Company has deferred the related expenses or benefits as regulatory assets or liabilities, respectively, for later amortization and inclusion in customer prices, pending OPUC review and authorization.

**Power Costs**—Pursuant to the AUT process, PGE files annually an estimate of power costs for the following year. As part of its 2014 GRC, PGE included a projected \$17 million reduction in power costs in its request for an overall increase in revenues. The power cost portion of the request was moved to a separate docket at the OPUC and was approved and included in the overall \$61 million annual revenue increase authorized by the OPUC in the Company's 2014 GRC with new prices beginning January 1, 2014.

Under the PCAM for 2013, NVPC were within the limits of the deadband, thus no potential refund or collection was recorded. The OPUC then issued an order in October 2014 that affirmed no refund or collection would be made during 2015 under the PCAM for 2013.

**Renewable Resource Costs**—Pursuant to its RAC, 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.

In March 2014, PGE submitted to the OPUC a renewable adjustment clause filing requesting deferral and recovery of the net revenue requirement of Tucannon River in the event that the facility were to come online prior to the inclusion of the project in base rates as proposed in the 2015 GRC. The Company estimates that the project will be in service between December 2014 and March 31, 2015.

PGE did not submit a RAC filing to the OPUC in 2013 as it did not place renewable resources into service during 2013.

**Decoupling**—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 approved general rate case.

Pursuant to the Company's 2014 GRC, the OPUC approved a change in the refund or collection period such that it will begin January 1, rather than June 1. Accordingly, collection of the estimated \$5 million recorded during 2013 is expected, subject to OPUC approval, to occur largely over a one year period beginning January 1, 2015.

For the nine months ended September 30, 2014, the Company has recorded an estimated refund of \$3 million. Any resulting refund to customers for the 2014 year would begin January 1, 2016.



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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. A regulatory asset of \$16 million was recorded in 2012, for potential recovery in customer prices, subject to an earnings test, with an offsetting credit to Depreciation and amortization expense. The OPUC authorized recovery of the deferred costs over a one year period, with a resulting tariff effective January 1, 2014. During 2013, the Company deferred an additional \$18 million of costs associated with these projects and in July 2014 filed for recovery of the additional costs, subject to an earnings test, with new customer prices expected to be effective in January 2015.

Boardman Operating Life Adjustment—As part of the 2014 GRC, the incremental depreciation expense that resulted from the shortened Boardman life was included in base customer prices, while recovery of the decommissioning costs continue under this separate tariff. During the second quarter of 2014, the OPUC approved the request for recovery of additional decommissioning costs that resulted from the acquisition of the additional 15% interest in Boardman on December 31, 2013, which is expected to result in approximately \$3 million additional revenue in 2014. The tariff also provides for annual updates to decommissioning revenue requirements with revised prices to take effect each January 1.

PGE has signed an agreement to acquire, by December 31, 2014, the 10% ownership share in Boardman currently held by one of the co-owners. On September 18, 2014, the Company submitted to the OPUC a request for approval of the annual update of the decommissioning revenue requirements for 2015, which included the additional decommissioning costs related to this incremental 10% ownership. PGE applied to the FERC on September 19, 2014 for authorization to consummate the acquisition. A FERC order is anticipated by mid-November, 2014.

Integrated Resource Plan—PGE's IRP outlines how the Company will meet future customer demand and describes PGE's future energy supply strategy, assessing both new and existing technologies, market conditions, and regulatory requirements.

On March 27, 2014, PGE filed a new IRP (2013 IRP) with the OPUC, which outlines the Company's expectations for resource needs and resource portfolio performance over the next 20 years, and includes an "Action Plan," which covers PGE's proposed actions over the next two to four years (through 2017). Over this time period, the Company projects energy requirements and energy available through its generation resources and long-term power purchase agreements to be in approximate balance.

The Action Plan of the 2013 IRP 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;

- Acquire 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, acquire an additional 25 MW of demand response and 23MW of 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 photovoltaic 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 BPA's Open Access Transmission Tariff to interconnect new and existing resources in eastern Oregon to PGE's service territory.

The 2013 IRP also incorporates the three new resources that are currently under construction, which are expected to be in service between December 2014 and mid-2016. For additional information on these capital projects see “Capital Requirements and Financing” in the Overview section in this Item 2.

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On October 23, 2014, OPUC staff issued a draft report and proposed order on PGE's 2013 IRP. The OPUC staff has recommended that the OPUC acknowledge the 2013 IRP with minor modifications, and the preparation and submittal of additional studies. The Company expects the OPUC to consider PGE's 2013 IRP at a public meeting in November.

## Critical Accounting Policies

PGE's critical accounting policies are outlined in Item 7 of the Company's Annual Report on Form 10 K for the year ended December 31, 2013, filed with the SEC on February 14, 2014.

## Results of Operations

The following table contains condensed consolidated statements of income information for the periods presented (dollars in millions):

	Three Months Ended			Nine Months Ended				
	September 30,			September 30,				
	2014		2013	2014		2013		
Revenues, net	\$484	100 %	\$435	100 %	\$1,400	100 %	\$1,311	100 %
Purchased power and fuel	202	42	190	44	528	38	538	41
Gross margin	282	58	245	56	872	62	773	59
Other operating expenses:								
Production and distribution	60	12	54	12	181	13	169	13
Cascade Crossing transmission project	—	—	—	—	—	—	52	4
Administrative and other	54	11	49	12	164	11	158	12
Depreciation and amortization	76	16	62	14	224	16	186	14
Taxes other than income taxes	27	6	27	6	82	6	79	6
Total other operating expenses	217	45	192	44	651	46	644	49
Income from operations	65	13	53	12	221	16	129	10
Interest expense*	23	4	25	6	71	5	75	6
Other income:								
Allowance for equity funds used during construction	11	2	4	1	26	1	8	1
Miscellaneous income, net	1	—	3	1	1	—	5	—
Other income, net	12	2	7	2	27	1	13	1
Income before income tax expense	54	11	35	8	177	12	67	5
Income tax expense	16	3	4	1	46	3	10	1
Net income	38	8	31	7	131	9	57	4
Less: net loss attributable to noncontrolling interests	(1 )	—	—	—	(1 )	—	(1 )	—
Net income attributable to Portland General Electric Company	\$39	8 %	\$31	7 %	\$132	9 %	\$58	4 %
* Includes an allowance for borrowed funds used during construction of	\$7		\$2		\$15		\$4	

Net income attributable to Portland General Electric Company was \$39 million, or \$0.47 per diluted share, for the third quarter of 2014, compared with \$31 million, or \$0.40 per diluted share, for the third quarter of 2013. The increase in Net income was driven by an increase in energy deliveries resulting from warmer weather and regional

economic growth, higher average retail prices resulting from the January 1, 2014 price increase authorized by the OPUC in the Company's 2014 GRC, lower net variable power costs, and an increase in AFDC resulting from a higher average CWIP balance driven by the construction of PW2, Tucannon River, and Carty.

Net income attributable to PGE for the nine months ended September 30, 2014 was \$132 million, or \$1.63 per diluted share, compared with \$58 million, or \$0.76 per diluted share, for the nine months ended September 30, 2013. The increase in Net income was driven by higher average retail prices resulting from the January 1, 2014 price increase authorized by the OPUC in the Company's 2014 GRC, lower net variable power costs, and an increase in AFDC resulting from a higher average CWIP balance. Additionally, during the second quarter of 2013, the Company charged to expense \$52 million of capitalized costs related to Cascade Crossing Transmission Project and recorded a refund of \$9 million to an industrial customer for cumulative over-billings over a period of several years, both of which were the primary drivers for the low effective tax rate in 2013.

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Three Months Ended September 30, 2014 Compared with the Three Months Ended September 30, 2013

Revenues, energy deliveries (presented in MWh), and the average number of retail customers were as follows for the periods presented:

	Three Months Ended September 30,					
	2014		2013			
Revenues <sup>(1)</sup> (dollars in millions):						
Retail:						
Residential	\$208	43	%	\$186	43	%
Commercial	176	37		162	37	
Industrial	59	12		55	13	
Subtotal	443	92		403	93	
Other retail revenues, net	(9	)	(2	)	—	—
Total retail revenues	434	90		403	93	
Wholesale revenues	39	8		22	5	
Other operating revenues	11	2		10	2	
Total revenues	\$484	100	%	\$435	100	%
Energy deliveries <sup>(2)</sup> (MWh in thousands):						
Retail:						
Residential	1,746	30	%	1,660	31	%
Commercial	2,026	34		1,957	37	
Industrial	1,138	19		1,098	21	
Total retail energy deliveries	4,910	83		4,715	89	
Wholesale energy deliveries	999	17		581	11	
Total energy deliveries	5,909	100	%	5,296	100	%
Average number of retail customers:						
Residential	735,940	87	%	728,816	87	%
Commercial	106,504	13		105,708	13	
Industrial	261	—		259	—	
Total	842,705	100	%	834,783	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.

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Total revenues increased \$49 million, or 11%, for the third quarter of 2014 compared with the third quarter of 2013, largely due to the \$31 million increase in Retail revenues resulting from the following:

A \$17 million increase related to 4.1% higher volumes of energy delivered, with increases of 5.2%, 3.5%, and 3.6% in residential, commercial and industrial energy deliveries, respectively. Increased deliveries were driven by warmer weather conditions, combined with increased demand resulting from the completion of new construction and high tech industry expansion. After adjusting for the effects of weather, total retail energy deliveries were up 3.5% for the third quarter of 2014 compared with the third quarter of 2013;

A \$16 million increase in the average retail price resulting from the January 1, 2014 price increase authorized by the OPUC in the Company's 2014 GRC; and

A \$5 million increase related to an increase in the average retail price for the collection of deferred costs related to four capital projects beginning January 1, 2014 (offset in Depreciation and amortization expense); partially offset by

A \$6 million decrease related to the decoupling mechanism, with a \$7 million potential refund to customers recorded in the third quarter of 2014 compared with a \$1 million potential refund recorded for the third quarter of 2013.

Total cooling degree-days for the third quarter of 2014 were 27% higher than the third quarter of 2013 and 52% above average. The following table indicates the number of heating and cooling degree-days for the third quarters of 2014 and 2013, along with 15-year averages provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-days		Cooling Degree-days	
	2014	2013	2014	2013
July	1	2	220	168
August	—	3	258	203
September	17	85	101	86
Third quarter	18	90	579	457
15-year average for the year-to-date	85	82	382	385

Wholesale revenues result from sales of electricity to utilities and power marketers in conjunction with 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 period to period as a result of economic conditions, power and fuel prices, hydro and wind conditions, and customer demand. The \$17 million, or 77%, increase in Wholesale revenues for the third quarter of 2014 compared with the third quarter of 2013, consisted of \$16 million related to a 72% increase in wholesale sales volume and \$1 million related to a 4% increase in average wholesale price.

Purchased power and fuel expense increased \$12 million, or 6%, for the third quarter of 2014 compared with the third quarter of 2013, and consisted of \$21 million related to an 11% increase in total system load, partially offset by \$9 million related to a 4% decrease in the average variable power cost per MWh. The decrease in the average variable power cost to \$35.18 per MWh in the third quarter of 2014 from \$36.79 per MWh in the third quarter of 2013 was largely due to an increase in energy received from thermal generation, which was partially offset by declines in energy received from hydro resources and wind generating resources. During the third quarter of 2013, the Company experienced unplanned outages at its Colstrip, Boardman, and Coyote Springs plants, driving an increase in the average cost per MWh resulting from the replacement of such energy with higher-cost purchased power during that period.



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The sources of energy for PGE's total system load, as well as its retail load requirement, were as follows for the periods presented:

	Three Months Ended September 30,					
	2014		2013			
Sources of energy (MWh in thousands):						
Generation:						
Thermal:						
Coal	1,479	26	%	830	16	%
Natural gas	1,282	22		1,096	21	
Total thermal	2,761	48		1,926	37	
Hydro	311	5		314	6	
Wind	332	6		372	7	
Total generation	3,404	59		2,612	50	
Purchased power:						
Term	916	16		940	18	
Hydro	352	6		385	8	
Wind	102	2		92	2	
Spot	977	17		1,147	22	
Total purchased power	2,347	41		2,564	50	
Total system load	5,751	100	%	5,176	100	%
Less: wholesale sales	(999	)		(581	)	
Retail load requirement	4,752			4,595		

Energy received from hydro resources during the third quarter of 2014, from both PGE-owned generating plants and purchased from mid-Columbia projects, decreased 5% compared with the third quarter of 2013. These resources provided approximately 14% and 15% of the Company's retail load requirement during the third quarters of 2014 and 2013, respectively. During the third quarter, total energy received from hydro resources exceeded projected levels included in PGE's AUT by 2% for 2014 and by 6% for 2013.

The following table presents the actual April-to-September 2014 and 2013 runoff at particular points of major rivers relevant to PGE's hydro resources (as a percentage of normal, as measured over the 30-year period from 1971 through 2000):

Location	Actual Runoff as a Percent of Normal *			
	2014		2013	
Columbia River at The Dalles, Oregon	108	%	100	%
Mid-Columbia River at Grand Coulee, Washington	110		108	
Clackamas River at Estacada, Oregon	97		102	
Deschutes River at Moody, Oregon	98		98	

\* Volumetric water supply percentages 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) decreased 11% in the third quarter of 2014 compared to the third quarter of 2013, and represented 7% of the Company's retail load requirement for the third quarter of 2014 compared with 8% for the third quarter of 2013. During the third quarter, energy received from Biglow Canyon fell short of projected levels included in the AUT by 17% for 2014 and by 20% for 2013.





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Actual NVPC, which consists of Purchased power and fuel expense net of Wholesale revenues, decreased approximately \$5 million for the third quarter of 2014 compared with the third quarter of 2013. The decrease was due to a 72% increase in wholesale sales volume combined with a 4% decline in the average variable power cost per MWh, which was offset by \$21 million related to an 11% increase in total system load. For the third quarters of 2014 and 2013, actual NVPC was \$5 million and \$9 million, respectively, above baseline NVPC.

Production and distribution expense increased \$6 million, or 11%, in the third quarter of 2014 compared with the third quarter of 2013. The increase is largely due to \$4 million higher maintenance expenses at PGE's generation facilities, \$1 million higher substation and line maintenance expenses, and \$1 million of additional operating costs as a result of the Company's ownership interest in Boardman increasing to 80% from 65% on December 31, 2013.

Administrative and other expense in the third quarter of 2014 increased \$5 million, or 10%, compared with the third quarter of 2013, driven by \$4 million more incentive compensation expense in 2014 largely resulting from the higher expected net income in 2014. In the third quarter 2014, pension expense decreased by \$1 million, which was offset by increases in other expenses.

Depreciation and amortization expense increased \$14 million, or 23%, in the third quarter of 2014 compared with the third quarter of 2013, with \$9 million related to timing of the deferral and amortization of costs of four capital projects as authorized in the Company's 2011 General Rate Case. In the third quarter of 2013, PGE deferred for future recovery \$5 million of costs related to these four projects and in the third quarter of 2014, the Company recorded \$4 million of amortization expense related to the recovery of these costs (offset in Retail revenues). Capital additions also increased Depreciation and amortization expense by \$3 million.

Interest expense decreased \$2 million, or 8%, in the third quarter of 2014 compared with the third quarter of 2013. A \$5 million decrease related to higher allowance for borrowed funds used during construction resulting from a higher average CWIP balance driven by the construction of PW2, Carty and Tucannon River was partially offset by an increase related to a higher average balance of debt outstanding in the third quarter of 2014.

Other income, net increased \$5 million in the third quarter of 2014 compared with the third quarter of 2013, which was primarily due to a \$7 million increase in the allowance for equity funds used during construction from the higher average CWIP balance partially offset by lower earnings on the non-qualified benefit plan trust assets.

Income tax expense was \$16 million in the third quarter of 2014 compared with \$4 million in the third quarter of 2013. The increase is largely due to the combination of higher pre-tax income for 2014 compared to 2013 and the timing of the recognition of production tax credits.

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Nine Months Ended September 30, 2014 Compared with the Nine Months Ended September 30, 2013

Revenues, energy deliveries (presented in MWh), and the average number of retail customers were as follows for the periods presented:

	Nine Months Ended September 30,					
	2014		2013			
Revenues <sup>(1)</sup> (dollars in millions):						
Retail:						
Residential	\$ 653	47	%	\$ 611	47	%
Commercial	493	35		461	35	
Industrial	164	12		160	12	
Subtotal	1,310	94		1,232	94	
Other retail revenues, net	(11)	)	(1)	)	(6)	)
Total retail revenues	1,299	93		1,226	94	
Wholesale revenues	73	5		59	4	
Other operating revenues	28	2		26	2	
Total revenues	\$ 1,400	100	%	\$ 1,311	100	%
Energy deliveries <sup>(2)</sup> (MWh in thousands):						
Retail:						
Residential	5,472	34	%	5,469	34	%
Commercial	5,621	34		5,540	34	
Industrial	3,196	20		3,186	20	
Total retail energy deliveries	14,289	88		14,195	88	
Wholesale energy deliveries	1,892	12		1,892	12	
Total energy deliveries	16,181	100	%	16,087	100	%
Average number of retail customers:						
Residential	734,792	87	%	727,579	87	%
Commercial	105,284	13		104,436	13	
Industrial	260	—		264	—	
Total	840,336	100	%	832,279	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.

Total revenues increased \$89 million, or 7%, for the nine months ended September 30, 2014 compared with the nine months ended September 30, 2013, largely due to the \$73 million increase in Retail revenues resulting from the following:

• A \$51 million increase in the average retail price resulting from the January 1, 2014 price increase authorized by the OPUC in the Company's 2014 GRC;

• A \$15 million increase related to an increase in the average retail price for the collection of deferred costs related to four capital projects beginning January 1, 2014 (offset in Depreciation and amortization expense);

• A \$9 million increase as a result of the industrial customer refund recorded in the second quarter of 2013 (reflected in Other retail revenues, net in the preceding table) related to cumulative over-billings during a period of several years as

a result of a meter configuration error; and

An \$8 million increase related to 0.7% higher volumes of energy delivered, with increases of 0.1%, 1.5%, and 0.3% in residential, commercial and industrial energy deliveries, respectively. After adjusting for the

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effects of weather, total retail energy deliveries were up 0.2% for the nine months ended September 30, 2014 compared with the nine months ended September 30, 2013; partially offset by

A \$7 million decrease related to the decoupling mechanism, with a \$3 million potential refund to customers recorded in the nine months ended September 30, 2014 compared with a \$4 million potential collection recorded for the nine months ended September 30, 2013; and

▲ \$3 million decrease related to various items, including other supplemental tariff changes.

Total heating degree-days for the nine months ended September 30, 2014 were 6% lower than the nine months ended September 30, 2013 and 8% below average, with cooling degree-days 18% higher than 2013 and 41% above average. The following table indicates the number of heating and cooling degree-days for the nine months ended September 30, 2014 and 2013, along with 15-year averages provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-days		Cooling Degree-days	
	2014	2013	2014	2013
First quarter	1,891	1,902	—	—
Second quarter	530	593	57	82
Third quarter	18	90	579	457
Year-to-date	2,439	2,585	636	539
15-year average for the year-to-date	2,662	2,653	452	453

Wholesale revenues for the nine months ended September 30, 2014 were \$14 million, or 24%, higher than the nine months ended September 30, 2013, and consisted of a 24% increase in average wholesale price.

Purchased power and fuel expense decreased \$10 million, or 2%, for the nine months ended September 30, 2014 compared with the nine months ended September 30, 2013, and consisted of \$12 million related to a 2% decrease in the average variable power cost per MWh, partially offset by \$2 million related to a slight increase in total system load. The decrease in the average variable power cost to \$33.42 per MWh in the nine months ended September 30, 2014 from \$34.18 per MWh in the nine months ended September 30, 2013 was driven by the economic displacement of a greater amount of thermal generation with purchased power during 2014 relative to 2013, combined with a decrease in the cost of natural-gas fired generation.

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The sources of energy for PGE's total system load, as well as its retail load requirement, were as follows for the periods presented:

	Nine Months Ended September 30,					
	2014		2013			
Sources of energy (MWh in thousands):						
Generation:						
Thermal:						
Coal	3,079	20	%	2,985	19	%
Natural gas	2,273	14		2,300	15	
Total thermal	5,352	34		5,285	34	
Hydro	1,292	8		1,231	8	
Wind	953	6		1,001	6	
Total generation	7,597	48		7,517	48	
Purchased power:						
Term	4,698	30		4,821	30	
Hydro	1,219	8		1,286	8	
Wind	267	1		269	2	
Spot	2,018	13		1,850	12	
Total purchased power	8,202	52		8,226	52	
Total system load	15,799	100	%	15,743	100	%
Less: wholesale sales	(1,892	)		(1,892	)	
Retail load requirement	13,907			13,851		

Energy received from hydro resources during the nine months ended September 30, 2014, from both PGE-owned generating plants and purchased from mid-Columbia projects, was comparable with the same period of 2013, and represented 18% of the Company's retail load requirement for each of those periods. Through September, total energy received from hydro resources exceeded projected levels included in the Company's AUT by 2% for 2014 and 2013.

Energy received from PGE-owned wind generating resources (Biglow Canyon) decreased 5% in the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013, and represented 7% of the Company's retail load requirement for each of those periods. Through September, energy received from Biglow Canyon fell short of projected levels included in the AUT by 9% for 2014 and 14% for 2013.

Actual NVPC, which consists of Purchased power and fuel expense net of Wholesale revenues, decreased approximately \$24 million for the nine months ended September 30, 2014 compared with the nine months ended September 30, 2013. The decrease was largely due to a 24% increase in the average wholesale sales price combined with a 2% decline in the average variable power cost per MWh. For the nine months ended September 30, 2014 and 2013, actual NVPC was \$9 million and \$5 million, respectively, below baseline NVPC.

Production and distribution expense increased \$12 million, or 7%, in the nine months ended September 30, 2014 compared with the nine months ended September 30, 2013. In 2014, storm related and service restoration costs, and distribution system labor were collectively \$6 million higher, and maintenance and overhaul expenses at PGE's generation facilities were \$6 million greater than in 2013. In addition, \$5 million higher operating costs resulted from the Company's ownership interest in Boardman increasing to 80% from 65% on December 31, 2013. Partially offsetting these increases was a \$4 million decrease due to a reserve recorded in the first quarter of 2013 related to the Company's benchmark bid, which was not selected as a winning bid in the request for proposal for renewable resources pursuant to PGE's 2009 IRP.



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Cascade Crossing transmission project of \$52 million in the nine months ended September 30, 2013 reflects the charge to expense of project costs previously recorded as CWIP. For further information, see “Electric Utility Plant, Net” in Note 2, Balance Sheet Components, in the Notes to Condensed Consolidated Financial Statements.

Administrative and other expense increased \$6 million, or 4%, in the nine months ended September 30, 2014 compared with the nine months ended September 30, 2013. The increase was due in large part to \$7 million more incentive compensation expense recorded in 2014 than in 2013 due to the higher net income expected in 2014. Additionally, outside services, medical premiums, provision for uncollectible accounts, and labor combined to increase expense \$5 million in 2014. Partially offsetting these increases were a \$4 million reduction in injuries and damages expense and a \$2 million reduction in pension expense.

Depreciation and amortization expense increased \$38 million, or 20%, in the nine months ended September 30, 2014 compared with the nine months ended September 30, 2013, with \$25 million related to timing of the deferral and amortization of costs of four capital projects as authorized in the Company’s 2011 General Rate Case. In the nine months ended September 30, 2013, PGE deferred for future recovery \$13 million of costs related to these four projects and in the nine months ended September 30, 2014, the Company recorded \$12 million of amortization expense related to the recovery of these costs (offset in Retail revenues). In addition, Depreciation and amortization expense increased by \$12 million due to the addition of capital assets.

Taxes other than income taxes expense increased \$3 million, or 4%, in the nine months ended September 30, 2014 compared with the nine months ended September 30, 2013, primarily due to higher property taxes resulting from increased property appraisal values.

Interest expense decreased \$4 million, or 5%, in the nine months ended September 30, 2014 compared with the nine months ended September 30, 2013. An \$11 million decrease related to higher allowance for borrowed funds used during construction resulting from a higher average CWIP balance driven by the construction of PW2, Carty, and Tucannon River. A \$7 million increase in interest expense resulted from a combination of an increase in the average balance of debt outstanding in the nine months ended September 30, 2014 partially offset by lower amortization expense in 2014 related to debt issuance costs.

Other income, net increased \$14 million in the nine months ended September 30, 2014 compared with the nine months ended September 30, 2013, primarily due to an \$18 million increase in the allowance for equity funds used during construction from the higher average CWIP balance, partially offset by a decrease in earnings from the Non-qualified benefit plan trust assets.

Income tax expense increased \$36 million in the nine months ended September 30, 2014 compared with the nine months ended September 30, 2013, with effective tax rates of 26.0% and 14.9%, respectively. The higher income tax expense and effective tax rate in 2014 are primarily due to the increase in pre-tax income in 2014 compared to 2013, which was driven by the charges to expense in 2013 related to Cascade Crossing and an industrial customer refund.



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## Liquidity and Capital Resources

## Capital Requirements

The following table presents PGE's estimated cash requirements for the years indicated (in millions, excluding AFDC):

	2014	2015	2016	2017	2018
Ongoing capital expenditures <sup>(1)</sup>	\$313	\$367	\$336	\$322	\$280
Port Westward Unit 2	128	13	—	—	—
Tucannon River Wind Farm	388	17	—	—	—
Carty Generating Station	114	166	35	—	—
Hydro licensing and construction <sup>(2)</sup>	37	22	10	2	1
Total capital expenditures	\$980	<sup>(3)</sup> \$585	\$381	\$324	\$281
Long-term debt maturities	\$—	\$375	\$67	\$58	\$75

(1) Consists primarily of upgrades to, and replacement of, transmission, distribution, and generation infrastructure, as well as new customer connections.

(2) Relates primarily to modifications to the Company's hydro facilities to enhance fish passage and survival, as required by conditions contained in the operating licenses.

(3) Includes preliminary engineering and removal costs, which are included in other net operating activities in the condensed consolidated statements of cash flows.

For additional information on PW2, Tucannon River, and Carty, see "Capital Requirements and Financing" in the Overview section of this Item 2.

For a discussion concerning PGE's ability to fund its future capital requirements, see "Debt and Equity Financings" in this Item 2.

## Liquidity

PGE's access to short-term debt markets, including revolving credit from banks, helps provide necessary liquidity to support the Company's current operating activities, including the purchase of power and fuel. Long-term capital requirements are driven largely by capital expenditures for distribution, transmission, and generation facilities to support both new and existing customers, 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):

	Nine Months Ended September 30,	
	2014	2013
Cash and cash equivalents, beginning of period	\$107	\$12
Net cash provided by (used in):		
Operating activities	473	459
Investing activities	(821	) (491
Financing activities	338	111
Change in cash and cash equivalents	(10	) 79
Cash and cash equivalents, end of period	\$97	\$91



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**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, such as depreciation and amortization, deferred income taxes, and pension and other postretirement benefit costs included in net income during a given period. The \$14 million increase in net cash flows from operating activities in the nine months ended September 30, 2014 compared with the nine months ended September 30, 2013 was largely due to an increase in Net income, net of non-cash items, and an increase in cash received from the Bonneville Power Administration to be returned to customers pursuant to the Residential Exchange Program. These increases were partially offset by a decrease in the amount received related to the settlement of a legal matter, and an increase in coal inventory at the Company’s Boardman plant.

Cash provided by operations includes the recovery in customer prices of non-cash charges for depreciation and amortization. PGE estimates that such charges in 2014 will range from \$295 million to \$305 million. Combined with other sources, total cash expected to be provided by operations is estimated to range from \$470 million to \$500 million.

**Cash Flows from Investing Activities**—Cash flows used in investing activities consist primarily of capital expenditures related to new construction and improvements to PGE’s distribution, transmission, and generation facilities. The \$330 million increase in net cash used in investing activities in the nine months ended September 30, 2014 compared with the nine months ended September 30, 2013 was driven by a \$371 million increase in capital expenditures resulting primarily from the construction of three new generation projects (PW2, Tucannon River and Carty).

The Company plans approximately \$1 billion of capital expenditures for 2014, which compares to 2013 capital expenditures of \$656 million. PGE plans to fund the 2014 capital expenditures with cash expected to be generated from operations during 2014, as discussed above, as well as with proceeds received from the issuances of debt securities. For additional information, see “Capital Requirements” and “Debt and Equity Financings” in the Liquidity and Capital Resources section of this Item 2.

**Cash Flows from Financing Activities**—Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. During the nine months ended September 30, 2014, net cash provided by such activities consisted of net proceeds received from the issuances of term bank loans of \$305 million and FMBs of \$100 million, partially offset by the payment of dividends of \$66 million. During the nine months ended September 30, 2013, net cash provided by financing activities consisted of net proceeds received from the issuance of FMBs in the amount of \$225 million and common stock in the amount of \$67 million, partially offset by the repayment of FMBs of \$100 million and commercial paper of \$17 million, and the payment of dividends of \$62 million.

**Dividends on Common Stock**

While the Company expects to pay regular quarterly dividends on its common stock, the declaration of any dividends is at the discretion of the Company’s Board of Directors. The amount of any dividend declaration will depend upon factors that the Board of Directors deems relevant, which may include, among other things, PGE’s results of operations and financial condition, future capital expenditures and investments, and applicable regulatory and contractual restrictions.

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Common stock dividends declared during 2014 consist of the following:

Declaration Date	Record Date	Payment Date	Dividends Declared Per Common Share
February 19, 2014	March 25, 2014	April 15, 2014	\$0.275
May 7, 2014	June 25, 2014	July 15, 2014	0.280
July 24, 2014	September 25, 2014	October 15, 2014	0.280
October 23, 2014	December 26, 2014	January 15, 2015	0.280

## 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 cash and liquidity to meet the Company's anticipated capital and operating requirements. However, the Company's ability to issue long-term debt and equity could be adversely affected by changes in capital market conditions.

PGE expects to fund 2014 estimated capital requirements with cash from operations (which is expected to range from \$470 million to \$500 million) and a combination of proceeds from long-term bank loans and issuances of FMBs.

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:

▲ \$400 million syndicated credit facility scheduled to expire November 2018; and

▲ \$300 million syndicated credit facility scheduled to expire December 2017.

These revolving credit facilities supplement operating cash flow 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 September 30, 2014, PGE had no borrowings outstanding under the revolving credit facilities, no commercial paper outstanding, and \$9 million of letters of credit issued. As of September 30, 2014, the aggregate available capacity under the revolving credit facilities was \$691 million.

Additionally, the Company has two letters of credit facilities under which it may issue letters of credit in an aggregate amount not to exceed \$60 million. As of September 30, 2014, the Company had \$55 million of letters of credit issued.

Long-term Debt. During the nine months ended September 30, 2014, PGE entered into two long-term debt transactions, which are described below.

In May, PGE entered into an unsecured credit agreement with certain financial institutions, under which, the Company may obtain four separate term loans in an aggregate principal amount of \$305 million. During the second quarter of 2014, PGE obtained three \$75 million term loans, for an aggregate amount of \$225 million. The Company obtained the fourth term loan in the amount of \$80 million during the third quarter of 2014. The interest rate for the loans is floating based on LIBOR plus 70 basis points.



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The credit agreement expires October 30, 2015, at which time any amounts outstanding under the term loans become due and payable. Upon the occurrence of certain events of default, the Company’s obligations under the credit agreement may be accelerated. Such events of default include payment defaults to lenders under the credit agreement, covenant defaults and other customary defaults.

In May, PGE entered into a bond purchase agreement with certain institutional buyers under which the Company agreed to issue, in three tranches, an aggregate principal amount of \$280 million of FMBs. During the third quarter of 2014, a 4.39% Series, due 2045, in the amount of \$100 million was issued and funded. On October 15, 2014, a 4.44% Series, due 2046, in the amount of \$100 million was issued and funded, and a 3.51% Series, due 2024, in the amount of \$80 million is expected to be issued and funded on or about November 17, 2014.

As of September 30, 2014, total long-term debt outstanding was \$2,321 million, of which \$70 million matures in January 2015 and is classified as current. In addition, PGE owns \$21 million of its Pollution Control Revenue Bonds, which may be remarketed at a later date, at the Company’s option.

Equity. PGE has an EFSA, whereby a forward counterparty borrowed 11,100,000 shares of the Company’s common stock from third parties and such borrowed shares were sold in a registered public offering in 2013. PGE receives proceeds from the sale of the common stock when the EFSA is physically settled. In 2013, the Company issued 700,000 shares pursuant to the EFSA and received net proceeds of \$20 million. As of September 30, 2014, 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 \$278 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 6, Equity, in the Notes to the Condensed Consolidated Financial Statements.

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. The Company attempts to maintain a common equity ratio (common equity to total consolidated capitalization, including any current debt maturities) of approximately 50%. Achievement of this objective, while sustaining sufficient cash flow, is necessary to maintain investment grade credit ratings and allow access to long-term capital at the most favorable interest rates available. PGE’s common equity ratios were 44.9% and 48.7% as of September 30, 2014 and December 31, 2013, respectively.

Credit Ratings and Debt Covenants

PGE’s secured and unsecured debt is rated investment grade by Moody’s Investors Service (Moody’s) and Standard and Poor’s Ratings Services (S&P). PGE’s current credit ratings and outlook are 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

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 related 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. These cash deposits are classified as Margin deposits, which is included in Other current assets on PGE’s condensed

consolidated balance sheets, while any letters of credit issued are not reflected on the Company's condensed consolidated balance sheets.

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As of September 30, 2014, PGE had posted approximately \$23 million of collateral with these counterparties, consisting of \$5 million in cash and \$18 million in letters of credit. Based on the Company's energy portfolio, estimates of energy market prices, and the level of collateral outstanding as of September 30, 2014, the approximate amount of additional collateral that could be requested upon a single agency downgrade to below investment grade was approximately \$62 million and decreases to approximately \$38 million by December 31, 2014, and \$27 million by December 31, 2015. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade was approximately \$155 million at September 30, 2014 and decreases to approximately \$113 million by December 31, 2014, and \$73 million by December 31, 2015.

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 FMBs. PGE estimates that on September 30, 2014, under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust, the Company could have issued up to approximately \$693 million of additional FMBs. Any issuances of FMBs would be subject to market conditions and amounts could be further limited by regulatory authorizations or by covenants and tests contained in other financing agreements. PGE 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 65.0% of total capitalization (debt ratio). As of September 30, 2014, the Company's debt ratio, as calculated under the credit agreements, was 55.1%.

### Off-Balance Sheet Arrangements

PGE has an EFSA, which the Company may settle with the 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 6, Equity, in the Notes to the Condensed Consolidated Financial Statements.

In May 2014, the Company entered into a bond purchase agreement, under which PGE agreed to sell to certain institutional buyers, in three tranches, an aggregate principal amount of \$280 million of FMBs. As of September 30, 2014, \$180 million of FMBs remained to be issued, of which \$100 million was issued in October, and \$80 million is expected to be issued in mid-November 2014. For further information, see "Long-term Debt" in Note 2, Balance Sheet Components, in the Notes to Condensed Consolidated Financial Statements.

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.

### Contractual Obligations

PGE's contractual obligations for 2014 and beyond are set forth in Part II, Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2013, filed with the SEC on February 14, 2014. Such obligations have not changed materially as of September 30, 2014, with the following exceptions:



During the second and third quarters of 2014, PGE obtained a total of four term loans pursuant to a credit agreement, for an aggregate amount of \$305 million. The interest rates for the loans are based on LIBOR. The credit agreement expires October 30, 2015, at which time any amounts outstanding under the term loans become due and payable;

During the third quarter of 2014, the Company issued \$100 million of 4.39% Series FMBs, due 2045; and

During the third quarter of 2014, PGE entered into an agreement with The Confederated Tribes of the Warm Springs Reservation of Oregon (the Tribes), whereby the Tribes have agreed to relinquish their right to sell their share of the energy generated from the Pelton/Round Butte hydroelectric project to a third party, and sell the energy to PGE for the period of January 1, 2015 through December 31, 2024. The Tribes' share of the Pelton/Round Butte hydroelectric projects represents 155 MW of capacity, with actual energy received dependent upon river flows.

As a result of the preceding transactions, estimated future principle payments for the contractual obligations presented are as follows (in millions):

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	2014	2015	2016	2017	2018	There- after	Total
Long-term debt	\$—	\$375	\$67	\$58	\$75	\$1,746	\$2,321
Interest on long-term debt *	110	112	104	103	99	1,509	2,037
Purchased power and fuel:							
Electricity purchases	240	178	170	143	149	857	1,737
Capacity contracts	22	27	26	6	6	25	112

\* Future interest on long-term debt is calculated based on the assumption that all debt remains outstanding until maturity.

### Item 3. 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. There have been no material changes to market risks affecting the Company from those set forth in Part II, Item 7A of the Company's Annual Report on Form 10-K for the year ended December 31, 2013, filed with the SEC on February 14, 2014.

### Item 4. Controls and Procedures.

#### Disclosure Controls and Procedures

PGE's management, under the supervision and with the participation of its Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company's disclosure controls and procedures as required by Exchange Act Rule 13a-15(b) as of the end of the period covered by this report. Based on that evaluation, PGE's Chief Executive Officer and Chief Financial Officer have concluded that, as of September 30, 2014, these disclosure controls and procedures were effective.

#### Changes in Internal Control over Financial Reporting

There were no changes in PGE's internal control over financial reporting that occurred during the period covered by this quarterly report that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

## PART II - OTHER INFORMATION

### Item 1. Legal Proceedings.

For further information regarding PGE's legal proceedings, see "Legal Proceedings" set forth in Part I, Item 3 of the Company's Annual Report on Form 10-K for the year ended December 31, 2013, filed with the SEC on February 14, 2014 and Part II, Item 1 of the Company's Quarterly Report on Form 10-Q for the quarterly periods ended March 31, 2014 and June 30, 2014, filed with the SEC on April 29, 2014 and July 29, 2014, respectively.

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.

On October 2, 2014, the Oregon Supreme Court, in a unanimous decision, affirmed the February 6, 2013 Oregon Court of Appeals decision that upheld the OPUC order dated September 30, 2008.

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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.

In July 2014, the court denied both defendants’ motion to dismiss and plaintiffs’ motion for partial summary judgment. On August 27, 2014, the plaintiffs filed a second amended complaint. The defendant’s response to the second amended complaint was filed September 26, 2014. The second amended complaint continues to seek injunctive relief, declaratory relief, and civil penalties for alleged violations of the federal Clean Air Act. The plaintiffs state in the second amended complaint that it was filed, in part, to comply with the court’s ruling on the defendants’ motion to dismiss and plaintiffs’ motion for partial summary judgment. Discovery in this matter is ongoing with trial now scheduled for August 2015.

Item 1A. Risk Factors.

There have been no material changes to PGE’s risk factors set forth in Part I, Item 1A of the Company’s Annual Report on Form 10-K for the year ended December 31, 2013, filed with the SEC on February 14, 2014.

Item 6. Exhibits.

Exhibit Number	Description
3.1	Third Amended and Restated Articles of Incorporation of Portland General Electric Company (incorporated by reference to Exhibit 3.1 to the Company’s Current Report on Form 8-K filed May 9, 2014).
3.2	Tenth Amended and Restated Bylaws of Portland General Electric Company (incorporated by reference to Exhibit 3.2 to the Company’s Current Report on Form 8-K filed May 9, 2014).
31.1	Certification of Chief Executive Officer.
31.2	Certification of Chief Financial Officer.
32	Certifications of Chief Executive Officer and Chief Financial Officer.
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.

Certain instruments defining the rights of holders of other long-term debt of the Company 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. The Company hereby agrees to furnish a copy of any such instrument to the SEC upon request.

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SIGNATURE

Pursuant to the requirements 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.

PORTLAND GENERAL ELECTRIC  
COMPANY  
(Registrant)

Date: October 27, 2014

By: /s/ James F. Lobdell  
James F. Lobdell  
Senior Vice President of Finance,  
Chief Financial Officer and Treasurer  
(duly authorized officer and principal  
financial officer)