PORTLAND GENERAL ELECTRIC CO /OR/
Form 10-K
February 27, 2008
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2007

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Transition period from__________ to__________

Commission File Number 1-5532-99

PORTLAND GENERAL ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

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

121 SW Salmon Street, Portland, Oregon 97204

(Address of principal executive offices) (zip code)

Registrant s telephone number, including area code: **(503) 464-8000**

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

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

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

None

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of large accelerated filer, accelerated filer, and Smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer x	Accelerated filer ¨	Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

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

The aggregate market value of the voting stock held by non-affiliates of Portland General Electric Company, computed by reference to the price at which the common stock was last sold, as of the last business day of Portland General Electric Company s most recently completed second fiscal quarter was approximately $1,715,275,306. The number of shares of Portland General Electric Company s common stock outstanding at February 15, 2008 was 62,529,787 shares.

Documents Incorporated by Reference

Part III, Items 10 - 14	Portions of Portland General Electric Company s definitive proxy statement to be filed pursuant to Regulation 14A for the 2008 Annual Meeting of Shareholders to be held on May 7, 2008.

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DEFINITIONS

The following abbreviations or acronyms used in the text and notes to the consolidated financial statements are defined below:

Abbreviations or Acronyms	
AFDC	Allowance For Funds Used During Construction
Beaver	Beaver Combustion Turbine Plant
Biglow Canyon	Biglow Canyon Wind Farm
Boardman	Boardman Coal Plant
BPA	Bonneville Power Administration
Chapter 11 Plan	Supplemental Modified Fifth Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code, dated January 9, 2004 and as thereafter amended and supplemented from time to time
Colstrip	Colstrip Units 3 and 4 Coal Plant
Coyote Springs	Coyote Springs Unit 1 Generating Plant
CUB	Citizens Utility Board
Debtors	Enron Corp. and its reorganized debtor subsidiaries under the Chapter 11 Plan
DCR	Disputed Claims Reserve
DEQ	Oregon Department of Environmental Quality
Dth	Decatherm = 10 therms = 1,000 cubic feet of natural gas
EFSC	Energy Facility Siting Council
EITF	Emerging Issues Task Force of the Financial Accounting Standards Board
Enron	Enron Corp., as reorganized debtor pursuant to its Supplemental Modified Fifth Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the Bankruptcy Code, confirmed by the United States Bankruptcy Court For The Southern District of New York (Case No. 01-16034) on July 15, 2004 and effective November 17, 2004
EPA	U.S. Environmental Protection Agency
ESA	Endangered Species Act
ESS	Electricity Service Supplier
FERC	Federal Energy Regulatory Commission
Financial Statements	Consolidated Financial Statements of Portland General Electric Company included in Part II, Item 8 of this report
ISFSI	Independent Spent Fuel Storage Installation
kWh	Kilowatt-hour
MMBtu	One million British thermal units

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DEFINITIONS

Abbreviations or Acronyms	
MW	Megawatt
MWa	Average megawatts
MWh	Megawatt-hour
NRC	Nuclear Regulatory Commission
NVPC	Net Variable Power Costs
OATT	Open Access Transmission Tariff
OEQC	Oregon Environmental Quality Commission
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
PGE or the Company	Portland General Electric Company
Port Westward	Port Westward Power Plant
RVM	Resource Valuation Mechanism
SB 408	Oregon Senate Bill 408
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards (issued by the Financial Accounting Standards Board)
Trojan	Trojan Nuclear Plant
URP	Utility Reform Project
USDOE	United States Department of Energy

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Part I

Item 1. Business

General

Portland General Electric Company (PGE, or the Company), incorporated in 1930, is a publicly owned, vertically integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the State of Oregon. PGE also sells electricity and natural gas in the wholesale market to utilities and energy marketers in the western United States. PGE operates as a cost-based, regulated electric utility, for which revenue requirements are determined based upon the cost to serve customers, including a reasonable rate of return to the Company, and is obligated to provide full (bundled) service to all of its customers. The Company continues to operate as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis.

In 1997, Portland General Corporation, the former parent of PGE, merged with Enron Corp., with Enron continuing in existence as the surviving corporation and PGE operating as a wholly-owned subsidiary of Enron. In December 2001, Enron, along with certain of its subsidiaries, filed for Chapter 11 of the federal Bankruptcy Code. PGE was not included in the filing.

On April 3, 2006, in accordance with Enron s Chapter 11 Plan, the 42.8 million shares of PGE common stock held by Enron Corp. were cancelled, PGE issued 62.5 million shares of new common stock, and PGE and Enron entered into a separation agreement. Following issuance of the new PGE common stock, PGE ceased to be a subsidiary of Enron. Approximately 27 million shares of the new PGE common stock were initially issued to the Debtors creditors holding allowed claims, and approximately 35.5 million shares were issued to a Disputed Claims Reserve (DCR). On June 18, 2007, the Disputed Claims Reserve sold substantially all of its remaining holdings of PGE stock in a public offering. PGE s common stock is listed on the New York Stock Exchange under the ticker symbol POR .

PGE s state-approved service area allocation of approximately 4,000 square miles is located entirely within Oregon and includes 52 incorporated cities, of which Portland and Salem are the largest. The Company estimates that at the end of 2007 its service area population was approximately 1.6 million, comprising about 43% of the state s population. The Company added approximately 11,000 retail customers during 2007, and at December 31, 2007 served approximately 804,000 retail customers.

As of December 31, 2007, PGE had 2,705 employees. A total of 868 employees are covered under agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 837 employees for a five-year period effective from March 1, 2004 through February 28, 2009. In addition, 31 employees (18 at Coyote Springs and 13 at Port Westward) are covered under a five-year agreement that extends from August 2, 2006 through August 1, 2011.

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Available Information

The Company s annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available or may be accessed free of charge through the Investors section of the Company s Internet website at www.portlandgeneral.com as soon as reasonably practicable after the reports are electronically filed with, or furnished to, the Securities and Exchange Commission (SEC). It is not intended that the Company s website and the information contained therein or connected thereto be incorporated into this Annual Report on Form 10-K. Information may also be obtained via the SEC Internet website at www.sec.gov.

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Regulation and Rates

PGE is subject to federal and state regulation, both of which can have a significant impact on the business and operations of the Company. In addition to those activities and agencies discussed below, the Company is subject to regulation by certain environmental agencies, as described in Environmental Matters in this Item 1.

Federal Regulation

The Company is a licensee and a public utility, as those terms are defined in the Federal Power Act, and is subject to regulation by the Federal Energy Regulatory Commission (FERC) as to accounting policies and practices, licensing of hydroelectric projects, transmission services, wholesale sales, issuance of short-term debt, and other matters. The Energy Policy Act of 2005 (EPAct 2005) granted the FERC increased statutory authority to implement mandatory transmission and reliability standards, as well as enhanced oversight of power and transmission markets, including protection against market manipulation. Such standards, the majority of which apply to PGE, became effective on June 18, 2007. PGE has submitted mitigation plans related to certain standards to the Western Electricity Coordinating Council (WECC), with review and approval pending.

Wholesale - PGE has authority under its FERC tariff to charge market-based rates for wholesale energy sales. In June 2007, the FERC issued Order 697, *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, which changed the re-authorization requirements for continued use of market-based rates and requires the filing of updated market studies on a regional schedule. PGE s current authorization, which was due to expire in May 2008, will remain in effect until June 2010, when the Company, as part of the western region, will file for re-authorization.

Transmission - FERC Order 890, *Preventing Undue Discrimination and Preference in Transmission Services*, which became effective in July 2007, requires regional coordination of transmission planning. The order requires greater specificity and more transparency in the Open Access Transmission Tariff (OATT). PGE submitted a compliance filing to incorporate into its OATT the non-rate terms and conditions contained in the order and will submit additional filings to incorporate other provisions of the order. FERC Order 693, *Mandatory Reliability Standards for the Bulk-Power System*, issued in March 2007, approved mandatory reliability standards developed by the North American Electric Reliability Corporation, which is responsible for the enforcement of such standards.

As a major transmitting utility, PGE has participated in several transmission planning efforts in support of the coordinated expansion and enhanced operation of the regional transmission system. The Company will continue to monitor and engage in these efforts although there remains considerable uncertainty regarding their further development.

Pipeline - The Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 provide FERC authority in matters related to extension, enlargement, safety, and abandonment of jurisdictional pipeline facilities, as well as transportation rates and accounting for interstate natural gas commerce. PGE s 79% interest in the pipeline that provides natural gas to its Beaver and Port Westward plants is subject to this authority.

Nuclear - The Nuclear Regulatory Commission (NRC) regulates the licensing and decommissioning of nuclear power plants. In 1993, the NRC issued a possession-only license amendment to PGE s operating license for the Trojan Nuclear Plant (Trojan), and in early 1996 the NRC and Energy Facility Siting Council (EFSC) approved the Trojan Decommissioning Plan, which has allowed PGE to

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proceed in decommissioning the plant. The NRC approved the completed transfer of spent nuclear fuel from the Trojan spent fuel pool to a separately licensed dry cask storage system that will house the nuclear fuel on the plant site until permanent storage is available. PGE completed the radiological decommissioning of the Trojan site in December 2004 pursuant to an NRC-approved License Termination Plan, with the plant s Facility Operating License terminated by the NRC in May 2005. Spent fuel storage activities will continue to be subject to NRC regulation until all nuclear fuel is removed from the site, decontamination is completed, and the storage installation is fully decommissioned. The Oregon Department of Energy also monitors Trojan. For further information, see Note 13, Trojan Nuclear Plant, in the Notes to Consolidated Financial Statements.

State of Oregon Regulation

PGE is subject to the jurisdiction of the Public Utility Commission of Oregon (OPUC), which approves the Company s retail prices through general rate proceedings and supplemental tariffs and establishes conditions of utility service. Under Oregon law, the OPUC is required to ensure that the prices and terms of service are fair, non-discriminatory, and provide PGE an opportunity to earn a fair return on its investment. In addition, the OPUC regulates the issuance of stock and long-term debt, prescribes the system of accounts to be kept by Oregon utilities, and reviews applications to sell utility assets and engage in transactions with affiliated companies. Construction of new generating facilities in Oregon requires a permit from the state s EFSC.

General Rate Case - PGE periodically evaluates the need to change its overall general retail electric price structure to sufficiently cover its operating costs and provide a reasonable rate of return. The Company s most recent comprehensive general rate case, approved by the OPUC on January 12, 2007, resulted in an overall price increase of approximately 1.3%. The increase represented the combined effect of a 1.4% decrease related to general costs, which became effective on January 17, 2007, and a 2.8% increase related to cost recovery of Port Westward, which became effective on June 15, 2007. The change in retail prices was based upon a 50% equity capital structure, a 10.1% return on equity, and an overall rate of return of 8.29%. The OPUC had previously approved a 5.1% increase effective January 1, 2007 for projected increased power costs under the Resource Valuation Mechanism.

The Company filed a general rate case on late February 27, 2008 with the OPUC, based on a forecasted 2009 test year, with new prices expected to be effective beginning in January 2009. For further information, see the Overview section of Item 7. - Management s Discussion and Analysis of Financial Condition and Results of Operation.

Power Costs - In its general rate order, the OPUC also approved a process by which PGE can continue to adjust prices to reflect power cost forecasts for future years. An Annual Power Cost Update Tariff, which replaced the former Resource Valuation Mechanism, provides for rate adjustments to reflect updated forecasts of net variable power costs (NVPC) for future calendar years. In addition, a new Power Cost Adjustment Mechanism (PCAM) was approved by the OPUC, effective January 17, 2007. Under the PCAM, PGE can adjust future prices to reflect a portion of the difference between each year s forecasted NVPC included in prices (the baseline), and actual NVPC. Under the PCAM, PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and that included in base prices by application of an asymmetrical deadband within which PGE absorbs cost increases or decreases, with a 90/10 sharing of costs and benefits between customers and the Company outside of the deadband. A refund will occur only to the extent that it results in PGE s actual return on equity (ROE) for that year being no less than 100 basis points above the Company s last authorized ROE. A collection will occur only to the extent that it results in PGE s actual ROE for that year being no greater than 100 basis points below the Company s last authorized ROE.

For 2007, the deadband ranged from $11.7 million below, to $23.4 million above, the baseline. PGE s actual NVPC as determined under the PCAM for 2007 were less than the established baseline by $29.4 million. Accordingly, an estimated refund to customers of $16 million was recorded as a regulatory liability and is reflected as an increase to Purchased power and fuel expenses. Any regulatory asset or liability arising from application of the PCAM is subject to the results of a regulated earnings test, with final determination of any customer refund or collection made by the OPUC through a public filing and review. For 2008, the deadband will range from $14 million below, to $28 million above, baseline NVPC.

Retail Customer Choice Program - Implemented in 2002 as part of Oregon s electricity restructuring law, Oregon s customer choice program, along with related regulations and PGE s tariff, allows the Company s commercial and industrial customers direct access to other suppliers of electricity (Electricity Service Suppliers, or ESSs). While direct access customers purchase their electricity from other suppliers, PGE continues to deliver the energy to these customers. The program provides for a transition adjustment for customers that choose to purchase energy at market prices from investor-owned utilities or from ESSs. Such transition adjustments reflect the above-market or below-market cost, respectively, of energy resources owned or purchased by the utility and are designed to ensure that such costs or benefits do not unfairly shift to the utility s remaining energy customers. The retail customer choice program has no material effect on the financial condition or results of operations of the Company.

In 2007, the three ESSs registered to transact business with PGE served a total of 30 customers with a total average load of approximately 250 MWa, representing approximately 19% of PGE s non-residential load and 12% of the Company s total retail load.

Cost-of-service and market price options are also available to PGE s commercial and industrial customers. The Company offers an option by which certain large non-residential customers may, for a minimum three- or five-year term, elect to be removed from cost-of-service pricing, with energy supplied by an ESS or at a daily market rate by PGE. A total of 31 commercial and industrial customers were receiving service from PGE under market-based pricing options at the end of 2007.

Residential and small commercial customers can purchase electricity from PGE from a portfolio of rate options that include a basic cost-of-service rate, a time-of-use rate, and renewable resource rates. Approximately 60,000 customers have chosen renewable energy options and approximately 1,900 customers have chosen the time-of-use option.

Public Purpose Charge - The restructuring law also provides for a Public Purpose Charge to fund cost-effective conservation measures, new renewable energy resources, and weatherization measures for low-income housing. This charge, equal to 3% of retail revenues, has been extended to 2026 as part of Oregon s Renewable Energy Standards legislation that was passed in 2007. The Company remits amounts collected from retail customers to the Energy Trust of Oregon (ETO) and other agencies for administration of these programs.

Regulatory Accounting - PGE is subject to the provisions of Statement of Financial Accounting Standards No. (SFAS) 71, *Accounting for the Effect of Certain Types of Regulation*, and currently applies its provisions to reflect the effects of rate regulation in its financial statements. The Company periodically assesses the applicability of the statement to its business, or separable portions thereof. These assessments consider both the current and anticipated future rate environment and related accounting guidance, as outlined in SFAS 101, *Regulated Enterprises - Accounting for the Discontinuation of Application of SFAS No. 71*, and Emerging Issues Task Force Issue No. (EITF) 97-4, *Deregulation of the Pricing of Electricity - Issues Related to the Application of SFAS No. 71 and SFAS No. 101.*

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Customers and Revenues

PGE conducts retail electric operations exclusively in Oregon within a state-approved service area. Competitors within the Company s service territory include the local natural gas company, which competes in the residential and commercial space heating, water heating, and appliance markets, and fuel oil suppliers, which compete primarily for residential space heating customers. In addition, commercial and industrial customers may choose to purchase their energy requirements from alternative suppliers (ESSs), in accordance with Oregon s electricity restructuring law.

The following table summarizes PGE s revenues for the years indicated (dollars in millions):

	Years Ended December 31,					
	2007		2006		2005	
	Amount	%	Amount	%	Amount	%
Revenues:						
Retail	$ 1,516	87%	$ 1,367	90%	$ 1,305	90%
Wholesale	201	12%	135	9%	116	8%
Other operating revenues	26	1%	18	1%	25	2%
Total revenues	$ 1,743	100%	$ 1,520	100%	$ 1,446	100%

Retail

PGE serves a diverse retail customer base. Residential customers comprise approximately 88% of the Company s total customers, with the remainder comprised of commercial and industrial customers. Total retail revenues for 2007 were fairly evenly divided between residential (49%) and commercial and industrial (51%) customer classes. Residential demand is sensitive to the effects of weather, with demand highest during the winter heating season. Commercial and industrial customer classes are not dominated by any single industry. While the 20 largest customers constitute about 9% of total retail revenues, they represent nine different commercial and industrial groups, including high technology, paper manufacturing, metal fabrication, health services, and governmental agencies. No single customer represents more than 3% of PGE s total retail load or 2% of total retail revenues.

Wholesale

PGE participates in the wholesale marketplace in order to balance its supply of power to meet the needs of its retail customers, manage risk, and administer its current long-term wholesale contracts. The Company s wholesale market participation includes power purchases and sales resulting from economic dispatch decisions for its own generation, which allows PGE to secure reasonably priced power for its customers, and purchases and sales of natural gas. Interconnected transmission systems in the western states serve utilities with diverse load requirements and allow the Company to purchase and sell electricity within the region depending upon the relative price and availability of power, water conditions, and seasonal demand.

Most of PGE s wholesale sales are to utilities and power marketers and are predominantly short-term. The Company may net purchases and sales with the same counterparty (termed book outs) rather than simultaneously receiving and delivering physical power, with only the net amount of those purchases or sales required to meet retail and wholesale obligations physically settled.

Other Operating Revenues

Other operating revenues include sales of natural gas in excess of generating plant requirements and revenues from transmission services, pole contact rentals, and certain other electric services to customers.

For further information, including year-to-year comparisons of revenues, energy sales, and number of customers, see Item 7. - Management s Discussion and Analysis of Financial Condition and Results of Operation.

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Power and Fuel Supply

Power Supply

PGE relies upon its existing base of generating resources, as well as short- and long-term power contracts, to meet its customers energy needs. At December 31, 2007, PGE s total firm resource capacity, including short-term purchase agreements, was approximately 4,627 MW (net of short-term sales agreements of 757 MW).

The Pacific Northwest peak usage season historically occurs in the winter, when residential and commercial heating and lighting demand is highest. PGE s all-time high net system load peak (4,073 MW) occurred in December 1998. The Company s all-time summer peak (3,706 MW), driven by unusually warm weather and increased air conditioning demand, occurred in July 2006.

Generation

PGE s current generating portfolio consists of thermal (primarily coal and natural gas), hydro, and wind resources that together provide 2,449 MW of total net capability. See Item 2. - Properties for a full listing of PGE s generating facilities.

Thermal

The Company s thermal generation facilities continued to supply reliable power during 2007. In June 2007, Port Westward, a new 406 MW natural gas fired generating plant, was placed in service at a total cost of $280 million, including allowance for funds used during construction (AFDC).

Hydro

The Company s lowest cost generating resources are its FERC licensed hydroelectric projects. Northwest hydro conditions have a significant impact on the region s power supply, with water conditions significantly impacting PGE s cost of power and its ability to economically displace more expensive thermal generation and spot market power purchases. Current forecasts indicate near normal hydro conditions for 2008.

Wind

Biglow Canyon Wind Farm (Biglow Canyon), located in Sherman County, Oregon, is PGE s newest and largest renewable energy project. Phase I of Biglow Canyon, comprised of 76 wind turbines with a total capacity of 125 MW, was completed and placed in service in mid-December 2007 at a total cost of approximately $255 million (including AFDC). Phases II and III of the project are in the advanced planning stages, with an estimated total cost of $700 million to $800 million, including approximately $50 million of AFDC. Phase II is expected to be completed by the end of 2009 and Phase III is expected to be completed by the end of 2010. When completed, the three-phase project is expected to have a total installed capacity of 400 to 450 MW.

Purchased Power

PGE supplements its own generation with short- and long-term wholesale contracts as needed to meet its retail load requirements and provide the most economic mix on a variable cost basis. PGE also has firm contracts, ranging from one to thirty years, to purchase up to 975 MWa of power from counterparties, including Pacific Northwest utilities and the Confederated Tribes of the Warm Springs Reservation of Oregon. The 30-year agreement is for 27 MWa of wind capacity with an independent power producer. In addition, PGE has an exchange contract with a summer-peaking California utility to help meet the Company s winter-peaking requirements, and an exchange contract with another Northwest utility to help meet the Company s summer-peaking requirements. These resources, along

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with short-term contracts, provide the Company with sufficient firm capacity to serve its peak loads. For further information, see Power and Fuel Supply in Item 7. - Management s Discussion and Analysis of Financial Condition and Results of Operation.

Mid-Columbia Hydro Matters - The Company has long-term power purchase contracts with certain public utility districts in the State of Washington related to four hydroelectric projects on the mid-Columbia River. The contracts provide approximately 567 MW of firm capacity, and expire between 2009 and 2018. In 2001, PGE executed new agreements with Grant County Public Utility District (Grant), operator of the Priest Rapids and Wanapum projects, for periods corresponding to Grant s new license term, to be determined by the FERC. The Priest Rapids agreement became effective in November 2005 and the Wanapum agreement will become effective November 1, 2009. Both contracts, approved by the FERC, extend through the life of Grant s new license, which is expected to be approximately 50 years. Under the terms of the agreements, Grant will annually determine the output required for its purposes, while PGE will be required to purchase approximately 25% of the output in excess of Grant s requirements over the term of the new license, for which PGE will pay a proportional share of the project s debt service and operating costs. PGE s share in the projects is expected to steadily decline as Grant s needs increase, with the Company s share in the two projects reduced from the current 256 MW to an estimated 149 MW in 2010. Also under the agreements, PGE is to purchase an additional 50 MWa annually during the period 2006-2011.

For further information regarding PGE s power purchase contracts from mid-Columbia projects, see Note 9, Commitments and Guarantees, in the Notes to Consolidated Financial Statements.

Fuel Supply

PGE contracts for natural gas and coal supplies used to fuel the Company s thermal generating plants. PGE also uses forward, swap, option, and futures contracts to manage its exposure to volatility in natural gas prices. The Company acquires coal and natural gas as follows:

Coal

- ***Boardman* -** PGE has a purchase agreement that provides coal for Boardman s operating requirements through 2008. The coal, obtained from surface mining operations in Wyoming, is delivered by rail under two separate ten-year transportation contracts, the terms of which began January 1, 2004. Coal purchases in 2007, totaling 2.6 million tons, contained approximately 0.3% of sulfur by weight. Utilizing low sulfur coal, the plant emitted less than the limit allowed by the EPA of 1.2 pounds of sulfur dioxide (SO_2) per MMBtu.

- ***Colstrip* -** Coal for Colstrip Units 3 and 4, located in southeastern Montana, is obtained from an adjacent mine under a contract that expires in 2019. The contract requires that the coal not exceed a maximum sulfur content of 1.5% by weight. In 2007, actual sulfur content for coal used at Colstrip ranged from approximately 0.59% to 0.78% by weight. Available coal supplies are sufficient to meet future requirements of the plant. Coal purchases for PGE s share of Colstrip Units 3 and 4 totaled 1.4 million tons in 2007. Utilizing wet scrubbers to minimize SO_2 emissions, the plant operated in compliance with EPA s source-performance standards.

Natural Gas

- ***Beaver and Port Westward* -** PGE owns 79% of the Kelso-Beaver Pipeline, which directly connects both its Beaver and Port Westward generating plants to Northwest Pipeline, an interstate gas pipeline operating between British Columbia and New Mexico. PGE has received authorization from the FERC to transport natural gas for others under a Part 284 blanket transportation certificate.

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Currently, PGE transports gas on the Kelso-Beaver Pipeline for its own use under a firm transportation service agreement, with capacity offered on an interruptible basis to the extent not utilized by the Company.

Firm gas supplies for Beaver and Port Westward may be purchased up to 72 months in advance, based on anticipated operation of the plants. PGE has access to 87,000 Dth/day of firm gas transportation capacity to serve the two plants. In addition, PGE has contractual access, through April 2017, to natural gas storage in Mist, Oregon, from which it can draw in the event that gas supplies are interrupted or if economic factors require its use. PGE believes that sufficient market supplies of gas are available to fully meet anticipated requirements of Beaver and Port Westward for 2008.

- ***Coyote Springs -*** The Coyote Springs generating station utilizes 41,000 Dth/day of firm transportation capacity on three pipeline systems accessing gas fields in Alberta, Canada. Firm gas supplies for Coyote Springs, based on anticipated operation of the plant, may be purchased up to 72 months in advance. PGE believes that sufficient market supplies of gas are available to fully meet requirements of Coyote Springs for 2008.

Oil

- ***Beaver -*** The Beaver generating station has the capability to operate at full capacity on No. 2 diesel fuel oil when it is economic or if the plant s natural gas supply is interrupted. PGE had an approximate 12-day supply of oil at the plant site at December 31, 2007.

- ***Coyote Springs -*** The Coyote Springs plant has the capability to operate on oil, although such capability has been deactivated in order to optimize natural gas operations.

Reliability

Wholesale power market products, along with PGE s base of thermal, hydroelectric and wind generating capacity, currently provide the Company with the flexibility to respond to seasonal fluctuations in the demand for electricity from its retail and wholesale customers. Although surplus generation has diminished in recent years due to economic and population growth in the western United States, the recent construction of new generating plants has increased the region s capacity to meet its power needs. PGE anticipates that generating capacity within the WECC, as well as an active wholesale market, will continue to provide sufficient energy to supplement the Company s generation and purchases under current short- and long-term power contracts. To meet anticipated future requirements and help assure continued system reliability, PGE s integrated resource planning process utilizes input from several sources, including long-term forecasts prepared by both PGE and the WECC.

Integrated Resource Plan

PGE s Integrated Resource Plan (IRP), required by the OPUC, describes the Company s energy supply strategy. The primary goal of the IRP is to identify a resource action plan that, when considered with the Company s existing portfolio, provides the best combination of expected cost and associated risks and uncertainties for PGE and its customers.

PGE filed an IRP with the OPUC in June 2007 that covers the years 2008 through 2015. It includes additional renewable and demand-side resources, energy efficiency programs, power purchase agreements of varying terms, and the acquisition of additional peaking capacity. The plan was developed over an 18-month period that included significant research and discussion with customer groups, independent consultants, and regulators.

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The IRP Action Plan proposes the following:

- Continued development of Biglow Canyon, with wind turbines to provide a total maximum generating capacity of 400 to 450 MW. Phase I is complete with Phase II expected to be completed by the end of 2009, and Phase III by the end of 2010.

- Procurement of an additional 218 MWa of renewable power. Combined with Biglow Canyon and existing renewable resources, this will help PGE meet Oregon s new Renewable Energy Standard.

- Expansion of energy efficiency programs in partnership with the ETO. The goal is to increase the amount of load met through efficiency measures by an additional 45 MW (beyond the amount already targeted by the ETO) by 2012.

- Purchase power agreements with durations of five to ten years, intended to reduce reliance on spot market purchases, help stabilize customer prices, and meet electricity demand while giving new technologies time to mature and become cost-effective.

- Acquisition of 100 MW of peaking capacity, through ownership or contract, to meet an increase in forecasted winter and summer peak requirements and to facilitate the integration of variable wind generation.

- Seasonal capacity purchases of 508 MW.

Review of the IRP by stakeholders and the OPUC staff is continuing and will be completed when the OPUC determines the Action Plan appears reasonable and issues an acknowledgement order, which is expected in March 2008. The Company expects to issue a Request For Proposal for energy related resources shortly after acknowledgement of the IRP.

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Environmental Matters

PGE operates in a state recognized for environmental leadership. The Company s policy of environmental stewardship seeks to minimize environmental risk and waste in its operations and promote the efficient use of energy.

PGE s operations are subject to a wide range of environmental protection laws, including those related to air and water quality, noise, and waste disposal. The EPA and certain state agencies, including the Oregon Environmental Quality Commission (OEQC), the Oregon Department of Environmental Quality (DEQ), the Oregon Department of Energy, and the EFSC, have direct jurisdiction over environmental matters that include the siting and operation of generating facilities and the accumulation, cleanup, and disposal of toxic and hazardous wastes.

Climate Change

Greenhouse gas emissions and their potential impacts on climate change and global warming have recently received increased public attention, with several legislative efforts initiated to establish mandatory control of emissions from thermal electricity generating plants. PGE is participating as a stakeholder in the Western Climate Initiative, a regional accord with a stated goal of reducing greenhouse gas emissions to 15% below 2005 levels by the year 2020. Any future laws that impose mandatory reductions in carbon dioxide emissions could have a material impact on electric utilities that rely on coal as a fuel resource. PGE s ownership shares of the Boardman and Colstrip coal plants comprise approximately one-fourth of the Company s net generation capability.

Renewable Energy Standards

Renewable Energy Standards adopted by the 2007 Oregon legislature require that PGE and other large electricity providers serve at least 5% of their retail load within the state from renewable resources by the year 2011, increasing to 25% by 2025. Additional interim steps in the standard include meeting 15% of retail load by 2015 and 20% by 2020. Biglow Canyon, which is expected to have a total installed capacity of 400 to 450 MW when all three phases are completed by the end of 2010, represents a significant step toward the Company s achievement of these goals.

Air Quality Standards

PGE s operations, principally its fossil-fuel generation plants, are subject to the federal Clean Air Act (CAA). Primary pollutants addressed by the CAA that affect PGE are SO_2, nitrogen oxides, carbon monoxide, and particulate matter. State governments also monitor and administer certain portions of the CAA and must set standards that are at least equal to federal standards. Oregon s air quality standards currently exceed federal standards.

PGE manages its emissions by the use of low sulfur fuel, emission controls, emission monitoring, and combustion controls. The SO_2 emissions allowances awarded under the CAA, along with expected future annual allowances, are sufficient to operate Boardman at 60% to 67% of capacity. PGE has acquired additional emissions allowances, which, in combination with the allowance awards, are expected to allow PGE to meet the SO_2 emission requirements for the Boardman plant at forecasted capacity for at least the next ten years.

The federal government and the states in which PGE operates have adopted the following regulations concerning mercury emissions:

In May 2005, the EPA adopted the Clean Air Mercury Rule that establishes a cumulative total (cap) of mercury emissions from all electric generating plants in the United States and assigns to each state a mercury emissions budget.

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In October 2006, the Montana Board of Environmental Review adopted final rules on mercury emissions from coal-fired generating plants in Montana, including Colstrip, which set strict mercury emission limits by 2010.

In December 2006, the Oregon Environmental Quality Commission adopted the Utility Mercury Rule, which requires installation of mercury control technology at Boardman and requires that the plant reduce its mercury emissions by 90% by July 1, 2012.

In February 2008, the U.S. Court of Appeals for the District of Columbia Circuit published a unanimous decision vacating both the EPA s rule delisting coal- and oil-fired electric generating units from regulation under § 112 of the CAA and the Clean Air Mercury Rule. The Oregon Utility Mercury Rule was not directly affected by this decision; however, it contains significant components of the federal Clean Air Mercury Rule and thus it is reasonably likely that amendments will be required if the District of Columbia Circuit decision is not overturned.

In accordance with new federal regional haze rules aimed at visibility impairment in several federally protected areas, the DEQ is conducting an assessment of emission sources pursuant to a Regional Haze Best Available Retrofit Technology (BART) process. Several other states are conducting a similar process. Those sources determined to cause, or contribute to, visibility impairment at protected areas will be subject to a BART Determination.

In response to the EPA s regional haze rules, the Company volunteered to participate in a DEQ pilot project to analyze information about air emissions from Boardman. An exemption modeling analysis for identified sources, which began in September 2006, has indicated that the Boardman and Beaver generating plants may cause or contribute to visibility impairment in several federally protected areas. In November 2007, the Company submitted a BART Determination to the DEQ for Boardman that stated that the BART for Boardman is a combination of New Low NO_x Burners, Modified Over Fire Air System, Selective Non-Catalytic Reduction (SNCR), and Semi-dry Flue Gas Desulphurization, and that mercury emission regulations should be addressed through a Mercury Sorbent Injection System. The cost for these controls is estimated to be in the range of $300 million to $400 million (100% of total costs). While the Company believes that these controls meet BART requirements, it is possible that the regulatory agencies could require Selective Catalytic Reduction rather than SNCR, which would increase the estimated cost to a range of $470 million to $620 million (100% of total costs). The Company has no commitments in place at this time and cautions that the cost estimates are preliminary and subject to change. Final approval of the plan is expected to occur in the second half of 2009.

As the regulatory requirements are clarified by the relevant agencies and the related costs more closely estimated, PGE will further evaluate the economic prudency of these expenditures. In doing so, the Company will also consider additional costs, including taxes, emission fees and other costs that may be imposed under any future laws related to climate change. Such additional costs, as well as the requirement to install Selective Catalytic Reduction controls, could require an investment in excess of what the plant can economically support.

The ultimate impact that the above regulatory requirements and air emission controls will have on future operations, costs, or generating capacity of the Company s thermal generating plants is not yet determinable. PGE will seek to recover its share of any associated costs through the ratemaking process.

Restoration of Salmon Runs

Populations of most salmon species in the Pacific Northwest have declined significantly over the last several decades. Many of these distinct populations of salmon have been granted protection under the federal Endangered Species Act (ESA). Long-term recovery plans for these species include major operational changes to the region s hydroelectric projects. Significant changes thus far include modification in the timing of stored water releases, a spill program to assist juvenile salmon at federal dams located in the Columbia River and Snake River basins, and continued investment in fish protection infrastructure (ladders and screens). These changes have resulted in reductions at times in hydroelectric generation capability and the seasonal shifting of other generation from the fall and winter periods to the spring and summer periods.

PGE is implementing a series of salmon protection measures on the Clackamas, Deschutes, and Willamette rivers that were prescribed by the United States Fish and Wildlife Service and the National Marine Fisheries Service under their authority granted in the ESA and are contained in PGE s FERC operating licenses.

ESA consultations on PGE s Clackamas River project, completed in 2003, will be in effect until a new license is granted by the FERC. A settlement agreement related to the license application for the Company s four hydroelectric projects on the Clackamas River was submitted to the FERC in March 2006 for review and approval. Pending issuance of the new license, which is expected to occur in 2009, the project will continue to operate under annual licenses issued by the FERC.

In accordance with a 2002 agreement with state and federal agencies, environmental groups, and others, PGE is proceeding with the decommissioning of the Company s Bull Run hydroelectric project, which includes the Marmot and Little Sandy dams, located in the Sandy River basin. The Marmot Dam was removed in July 2007, with removal of the Little Sandy Dam planned for 2008.

As required under the 50-year license that the FERC issued to PGE in 2004 for its Pelton/Round Butte project on the Deschutes River, PGE began construction of a selective water withdrawal system in late 2007 in an effort to restore fish passage on the upper portion of the river. The system will collect juvenile salmon and steelhead and allow them to bypass the dam when migrating to the Pacific Ocean, and will regulate downstream water temperature. Completion of the system, at a total cost of approximately $105 million to $110 million, is expected in 2009. PGE s portion of the cost is expected to be approximately $80 million, including AFDC.

Hazardous Waste

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

PGE is also subject to regulation under the Comprehensive Environmental Response Compensation and Liability Act (CERCLA), also referred to as Superfund. CERCLA can assert joint and several liability for investigation and remediation costs regardless of fault or legality of original conduct. PGE is currently listed by the EPA as a Potentially Responsible Party (PRP) at two Superfund sites discussed below. Other hazardous waste spills are considered minor, with clean-ups conducted on a regular basis.

Nuclear Fuel Disposal

Under the Nuclear Waste Policy Act of 1982, the U.S. Department of Energy (USDOE) is responsible for the permanent storage and disposal of spent nuclear fuel. PGE has contracted with the USDOE for permanent disposal of spent nuclear fuel for Trojan. Trojan spent nuclear fuel is stored in the Independent Spent Fuel Storage Installation (ISFSI), an NRC-approved interim dry storage facility that

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houses the fuel at the plant site until the permanent off-site storage is available. No federal repository is expected to be available until after 2017. For further information concerning PGE s nuclear fuel disposal, see Note 13, Trojan Nuclear Plant, in the Notes to the Consolidated Financial Statements.

EPA Actions

PGE is currently involved in two matters, known as Portland Harbor and Harbor Oil, both of which have been included by the EPA on the federal National Priority List as federal Superfund Sites pursuant to CERCLA.

In 2000, PGE, along with sixty-eight other PRPs on the Portland Harbor Initial General Notice List, received a Notice of Potential Liability from the EPA with respect to the Portland Harbor Superfund Site. A 1997 investigation of a portion of the Willamette River by the EPA, known as Portland Harbor, revealed significant contamination of sediments within the harbor. In January 2008, PGE received a request from the EPA to provide additional information concerning its properties in or near the Portland Harbor Superfund Site. Sufficient information is currently not available to determine either the total cost of the investigation and remediation of the Portland Harbor or the liability of the PRPs, including PGE.

In 2005, PGE received a Special Notice Letter for Remedial Investigation/Feasibility Study from the EPA, in which the Company was named as one of fourteen PRPs with respect to the Harbor Oil Superfund Site, located in north Portland. Harbor Oil is the location of a company, Harbor Oil, Inc., that PGE and other entities used to process used oil from power plants and electrical distribution systems from at least 1990 until 2003. Sufficient information is currently not available to determine either the total cost of the investigation and remediation of the Harbor Oil site or the liability of the PRPs, including PGE.

For further information regarding these two matters, see Environmental Matters in Note 14, Contingencies, in the Notes to Consolidated Financial Statements.

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Item 1A. Risk Factors

Certain risks and uncertainties that may affect PGE s business, financial condition, results of operation and cash flows, or that may cause the Company s actual results to vary from the forward-looking statements contained in the Annual Report on Form 10-K, include those set forth below.

PGE is subject to the risk that the OPUC will not allow sufficient recovery of the Company s costs and thus not provide a reasonable rate of return to shareholders.

The prices that the OPUC allows PGE to charge for its retail services is the major factor in determining the Company s operating income, financial position, liquidity, and credit ratings. The OPUC has the authority to disallow recovery of any costs that it considers excessive or imprudently incurred. Further, the regulatory process does not provide assurance that PGE will be able to achieve earnings levels authorized.

The OPUC order in the Company s recent comprehensive general rate case, issued in January 2007, approved the use of a PCAM by which PGE can adjust future prices to reflect a portion of the difference between each year s forecasted and actual NVPC. However, use of the approved cost sharing (deadband) methodology will require that PGE absorb some power cost increases before the Company is allowed to recover any amount from customers. Accordingly, future application of the PCAM is expected to only partially mitigate the potentially adverse financial impact of unplanned generating plant outages, severe weather, reduced hydro availability, and volatile wholesale energy prices.

PGE faces regulatory and litigation risk with respect to recovery of the Company s investment in the closed Trojan Nuclear Plant.

There remains uncertainty regarding the ultimate outcome of legal and regulatory proceedings related to PGE s recovery of its investment in the Trojan Nuclear Plant, which was closed in 1993. For further information, see Trojan Investment Recovery within Legal Matters of Note 14, Contingencies, in the Notes to Consolidated Financial Statements. The Company cannot predict the ultimate outcome of this matter. However, while management believes that it will not have a material adverse impact on the financial condition of the Company, it may have a material adverse impact on results of operations and cash flows for future reporting periods.

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

Weather conditions can adversely affect PGE s revenues and costs and have an impact on the Company s financial and operating results. Temperatures outside the normal range can affect customer demand for electricity, with warmer-than-normal winters or cooler-than-normal summers reducing energy sales and revenues. Particularly for residential customers, weather conditions are the dominant cause of usage variations from normal seasonal patterns. Severe weather can also disrupt energy delivery and damage the Company s distribution system.

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

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

Unplanned outages at the Company s generating plants could result in replacement power costs greater than those power costs included in customer prices, and any inability to recover such costs in future rates could have a negative impact on the Company s results of operations. As indicated above, application of the Company s PCAM can be expected to mitigate adverse financial impacts of future unplanned outages at the Company s generating plants.

Weather conditions that reduce stream flows could adversely affect the Company s hydro production and increase the Company s generation or power purchase costs required to meet the shortfall.

PGE derives a portion of its power supply from its hydroelectric facilities and from those owned by certain public utility districts in the State of Washington and the City of Portland, with whom the Company has long-term power purchase contracts. Regional rainfall and snow pack levels affect stream flows and the resulting amount of generation available from these facilities. Shortfalls in low-cost hydro production will require increased generation from the Company s higher cost thermal plants and/or power purchases in the wholesale market, the adverse financial effects of which are not expected to be fully mitigated by the Company s PCAM.

Wholesale energy markets are subject to forces that are often not predictable and which can result in price volatility, deterioration of liquidity, and general market disruption, adversely affecting PGE s costs and ability to manage its energy portfolio and procure required energy supply.

Wholesale electricity prices in the western United States are influenced primarily by factors related to supply and demand. These factors include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth, and changes in technology. Volatility in wholesale energy markets can affect the availability and price of purchased power and demand for energy. Changes in the creditworthiness of large wholesale customers can also affect PGE s variable power costs. Further, disruption in wholesale markets may result in a deterioration of market liquidity, increase the risk of counterparty default, affect the regulatory and legislative process in unpredictable ways, affect wholesale energy prices, and impair PGE s ability to manage its energy portfolio. Changes in wholesale energy prices also affect the market value of derivative instruments and unrealized gains and losses, as well as cash requirements to purchase electricity. Although the Company s PCAM can be expected to partially mitigate the financial effects of adverse wholesale market conditions, cost sharing features of the mechanism do not provide for full recovery in customer prices.

Market risk related to adverse fluctuations in the price of natural gas purchased as fuel for electricity generation can also impact the Company s results of operations. PGE purchases natural gas in the open market or pursuant to short-term or variable-price contracts as part of its normal business operations. If market prices rise, especially during periods when the Company requires greater-than- expected volumes that must be purchased at market or short-term prices, PGE may incur greater costs than originally estimated. The Company may not be able to fully recover these increased costs through ratemaking.

Sustained downturns in the economy in its service territory could reduce demand for electricity and adversely affect the Company s results of operations.

Current and projected slowing of the Oregon and national economies could result in reduced demand for electricity that could decrease earnings and cash flow. Economic conditions can also impact the Company s ability to collect accounts receivable.

Measures required to comply with state and federal regulations related to emissions from thermal electric generating plants could result in increased capital expenditures and changes to the Company s operations that could increase operating costs, reduce generating capacity and adversely affect PGE s results of operations.

Oregon and federal regulators are currently considering the air emission standards applicable to PGE s thermal generating plants in Oregon as part of separate regulatory processes related to haze, mercury, and the Company s air permits. Oregon regulators have adopted measures that will require installation of mercury controls at the Boardman coal plant. Additional emissions controls may be required at PGE s Boardman coal plant, although specific measures will depend on the outcome of the regulators reviews. For further information regarding the total costs and the Company s portion, see Environmental Matters in Item 1. - Business.

In addition, PGE may be subject to litigation brought by environmental groups and other private parties alleging violations of state or federal law and seeking the imposition of penalties, injunctive relief, and the closure of plants. On January 15, 2008, PGE received a notice of intent to sue from a coalition of environmental groups alleging violations of the Clean Air Act and the Oregon State Implementation Plan relating to Boardman. The Company has not yet fully evaluated the claims referenced in the notice and cannot determine at this time its estimated exposure, if any. If the plaintiffs file their complaint and articulate their claims in greater detail, PGE will be better able to assess the likelihood, if any, that the claims will have a material adverse effect on the Company.

Montana regulators have adopted strict requirements related to mercury emissions that could impact the operations of Colstrip, in which PGE has a 20% ownership interest in units 3 and 4.

Although the full impact of required state and federal remediation measures is not yet determinable, they could have an adverse effect on future operations, operating costs, and generating capacity at both Boardman and Colstrip.

Adverse changes in the Company s credit ratings may negatively affect its access to the capital markets and cost of funds.

Access to capital markets is important to PGE s ability to operate. Increased scrutiny of the energy industry and the impacts of regulation, as well as changes in the Company s financial performance, could result in credit agencies re-examining its credit rating. A ratings downgrade could increase the interest rates and fees on PGE s revolving credit facility, increasing the cost of funding day-to-day working capital requirements, and could also require the Company to pay higher interest rates on future long-term debt. In addition, access to the commercial paper market, a principle source of short-term borrowings, could be restricted, resulting in higher interest costs. The Company s secured and unsecured debt is currently rated at investment grade by Moody s Investors Service and Standard and Poor s. Should Moody s and/or Standard and Poor s reduce their rating on the Company s unsecured debt to below investment grade, PGE could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral.

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

The Company relies on suppliers to deliver natural gas, coal and electricity, in accordance with short- and long-term contracts. Failure of suppliers to comply with existing contracts in a timely manner, could disrupt PGE s ability to deliver electricity and require the Company to incur additional expenses to meet the needs of its customers. In addition, as these contractual agreements expire, PGE may be unable to continue to purchase natural gas, coal or electricity on terms and conditions equivalent to those of current agreements. Cost and availability of fuel supplies, primarily natural gas and coal, can also impact the cost and output of the Company s thermal generating plants.

The construction of new generating facilities, or modifications to existing facilities, may be subject to risks that result in disallowance of certain costs for recovery in prices, reduced plant efficiency, or higher operating costs.

Increases in both the number of customers and demand for energy will require continued expansion and reinforcement of PGE s generation, transmission, and distribution systems. Construction of new generating facilities, or modifications to existing facilities, may be affected by various factors, including unanticipated delays and cost increases, which could result in the disallowance of certain costs in the rate determination process. In addition, if construction projects are not completed according to specifications, reduced plant efficiency and higher operating costs could result. Equipment failure, the ability of generating plants to operate as intended, and other factors can result in plant performance that falls below expected levels.

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

A portion of PGE s total energy requirement is comprised of generation from hydroelectric projects on the Columbia, Clackamas, Deschutes, Willamette, and Sandy rivers. Operations of these projects are subject to extensive regulation related to the protection of fish and wildlife. The listing of various species of salmon, wildlife, and plants as threatened or endangered species has resulted in significant changes to federally-authorized activities, including those of hydroelectric projects. Salmon recovery plans could include further major operational changes to the region s hydroelectric projects, including those owned by PGE and those from which the Company purchases power under long-term contracts. In addition, new interpretations of existing laws and regulations could be adopted or become applicable to such facilities, which could further increase required expenditures for salmon recovery and endangered species protection and reduce the amount of hydro generation available to meet the Company s energy requirements.

Legislative efforts to reduce carbon emissions, in response to concerns related to climate change and global warming, could lead to increased capital and operating costs and have an adverse impact on the Company s operations and operating results.

The outcome of legislative efforts regarding carbon dioxide emissions, whether at the federal, regional, or state level, or the timing of any such laws or regulations that may be enacted, could have a material adverse affect on future results of operations and cash flows unless the additional costs incurred to comply with such laws or regulations can be recovered through regulated rates and/or future market prices for electricity. The Company would seek to recover through the ratemaking process any capital and operating costs of additional emission control equipment or emission reduction measures, such as the cost of sequestration or purchasing allowances, or offset credits that may be required.

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

From time to time in the normal course of its business, PGE is subject to various regulatory proceedings, lawsuits, claims and other matters, which may result in adverse judgments, settlements, fines, penalties, injunctions, or other relief. These actions are subject to many uncertainties and management cannot predict the outcome of individual matters with assurance. The final resolution of some of the matters in which the Company is involved could require the Company to make additional expenditures, in excess of established reserves, over an extended period of time and in a range of amounts that could have an adverse effect on PGE s cash flows and results of operations. Similarly, the terms of resolution could require the Company to change its business practices and procedures, which could also have an adverse affect on PGE s cash flows, financial position or results of operations.

Certain legal and regulatory proceedings, such as the proceedings related to refunds on wholesale market transactions in the Pacific Northwest described in Note 14, Contingencies, in the Notes to Consolidated Financial Statements and in Item 3. - Legal Proceedings, may have an adverse affect on results of operations and cash flows for future reporting periods.

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

PGE is subject to regulation by the FERC and the OPUC, and by federal, state and local authorities under environmental laws. Regulation affects almost every aspect of the Company s business. Changes to these regulations are ongoing, and the Company cannot predict the future course of changes in this regulatory environment or the ultimate effect that this changing regulatory environment will have on the Company s business. However, changes in these regulations can cause delays in or affect business planning and transactions and can substantially increase the Company s costs.

PGE has an aging workforce with a significant number of employees approaching retirement age.

The Company anticipates higher than previous averages of retirement rates over the next ten years and may need to replace a significant number of employees in key positions. PGE s ability to successfully implement a workforce succession plan is dependent upon the Company s ability to employ and retain skilled professional and technical workers. Without a skilled workforce, the Company s ability to provide quality service to its customers and meet regulatory requirements will be tested and could affect operating results.

Conditions that may be imposed in connection with hydroelectric license renewals may require large capital expenditures.

PGE is currently involved in renewing the federal license for its hydroelectric projects on the Clackamas River. The FERC, under the Federal Power Act, may impose conditions with respect to environmental, operating and other matters in connection with the renewal of PGE s license. The Company cannot predict with certainty the requirements that may be imposed during the relicensing process, the economic impact of those requirements, whether a new license will ultimately be issued or whether PGE will be willing to meet the relicensing requirements to continue operating its Clackamas hydroelectric projects.

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Storms and other natural disasters could damage the Company s facilities and disrupt its delivery of electricity resulting in significant property loss or repair costs and customer dissatisfaction.

The Company has exposure to natural disasters that can cause significant physical damage to its generation, transmission, and distribution facilities. Such events can interrupt the delivery of electricity, increase repair and service restoration expenses, and reduce revenues. Such events, if repeated or prolonged, can also affect customer satisfaction and the level of regulatory oversight. As a regulated utility, the Company is required to provide service to all customers within its service territory and generally has been afforded liability protection under the tariff against customer claims related to service failures beyond the Company s reasonable control. To the extent reasonably possible, the Company utilizes insurance as a means to mitigate the risk of physical loss of or damage to the Company s property resulting from natural disasters. However, such insurance may be subject to certain coverage restrictions and deductibles.

PGE is subject to political processes that may adversely affect its business.

Customer groups in certain geographic areas and certain governmental entities could attempt to acquire PGE facilities and equipment in the Company s allocated service territory through the use of public ownership initiatives, utilizing initiative petition and condemnation processes.

Item 1B. Unresolved Staff Comments

None.

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Item 2. Properties

The Company s principal plants, generating facilities and hydro storage reservoirs are located on land owned by the Company in fee or land under the control of the Company pursuant to existing leases, federal or state licenses, easements or other agreements. In some cases, meters and transformers are located on customer property. The Company leases its corporate headquarters complex, located in Portland, Oregon. The Indenture securing the Company s First Mortgage Bonds constitutes a direct first mortgage lien on substantially all utility property and franchises, other than expressly excepted property. The Company s service territory and generating facilities are indicated on the map below:

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The following are generating facilities owned by PGE:

Facility	Location	Net MW Capability [a] at December 31, 2007
Wholly-Owned:		
Hydro -		
Faraday	Clackamas River	46
North Fork	Clackamas River	58
Oak Grove	Clackamas River	44
River Mill	Clackamas River	25
Bull Run (b)	Sandy River	15
T.W. Sullivan	Willamette River	17
Natural Gas/Oil -		
Beaver	Clatskanie, Oregon	505
Coyote Springs	Boardman, Oregon	234
Port Westward	Clatskanie, Oregon	406
Wind -		
Biglow Canyon	Sherman County, Oregon	125
Jointly-Owned (c):		
Coal -		
Boardman (d)	Boardman, Oregon	380
Colstrip 3 and 4 (e)	Colstrip, Montana	296
Hydro -		
Pelton (f)	Deschutes River	73
Round Butte (f)	Deschutes River	225
Total		**2,449**

(a) Capability based on generation under normal operating conditions.
(b) Decommissioning planned for 2008.
(c) Net MW Capability reflects PGE s ownership share.
(d) PGE operates Boardman and has a 65% ownership interest.
(e) PPL Montana, LLC operates Colstrip 3 and 4; PGE has a 20% ownership interest.
(f) PGE operates Pelton and Round Butte and has a 66.67% ownership interest.

Hydro Relicensing

PGE holds FERC licenses under the Federal Power Act for its hydroelectric generating plants. The Company s Sullivan plant operates under a FERC license that expires in 2035, while the Pelton and Round Butte plants operate under a license that expires in 2055.

The Company filed an application with the FERC in 2004 to relicense the Clackamas River hydroelectric projects. A settlement agreement, resolving most of the issues raised in the relicensing proceeding and providing for a 45-year license term, was signed by the thirty-three participating parties

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in March 2006 and was submitted to the FERC for review and approval. The settlement agreement also provides for a collaborative process for the resolution of water temperature issues downstream of the project, which must be settled prior to the issuance of a new license. Pending approval of the new license, the project will operate under annual licenses issued by the FERC. It is expected that the FERC will issue a new license for the Clackamas River projects in 2009.

In October 2002, PGE entered into an agreement with state and federal agencies, conservation groups, and others regarding removal of the Company s 22 MW Bull Run hydroelectric project located in the Sandy River basin. The Marmot Dam was removed in July 2007, reducing the project s capability to 15 MW, with removal of the Little Sandy Dam planned for 2008. The FERC issued a surrender order in 2004 and an annual operating license in early 2005 that allows PGE to operate the project until the removal of Little Sandy Dam. PGE has fully recovered its remaining plant investment and is recovering approximately $17 million in estimated decommissioning costs over a ten-year period ending in 2011. Total decommissioning costs increased to an estimated $24 million at December 31, 2007, with the incremental costs expected to be recovered in future prices charged to customers.

Transmission

PGE owns and/or has contractual access to transmission lines that deliver electricity from its Oregon plants to its distribution system in its service territory and also to the Northwest grid. The Company also has ownership in, and contractual access to, transmission lines that deliver electricity from the Colstrip plant in Montana to PGE. In addition, PGE has contractual access to approximately 20% of the Pacific Northwest Intertie, a 4,800 MW transmission facility between John Day, in northern Oregon, and Malin, in southern Oregon near the California border. This line is used primarily for interstate purchases and sales of electricity among utilities, including PGE.

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Item 3. Legal Proceedings

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

Following the closure of Trojan, PGE, in its 1993 general rate filing, sought OPUC approval to recover through rates future decommissioning costs and full recovery of, and a rate of return on, its Trojan investment. PGE s request was challenged and PGE requested from the OPUC a Declaratory Ruling (Docket DR 10) regarding recovery of the Trojan investment and decommissioning costs. In August 1993, the OPUC issued a Declaratory Ruling in PGE s favor, citing an opinion issued by the Oregon Department of Justice that current law gave the OPUC authority to allow recovery of, and a return on, its Trojan investment and future decommissioning costs. The Declaratory Ruling was appealed to the Marion County Circuit Court, which upheld the OPUC s Declaratory Ruling in November 1994. The Citizens Utility Board (CUB) appealed the decision to the Oregon Court of Appeals.

In PGE s 1995 general rate case (Docket UE 88), the OPUC issued an order (1995 Order) granting PGE full recovery of Trojan decommissioning costs and 87% of its remaining undepreciated investment in the plant. The Utility Reform Project (URP) filed an appeal of the 1995 Order to the Marion County Circuit Court, alleging that the OPUC lacked authority to allow PGE to recover Trojan costs through its rates. The CUB also filed an appeal to the Marion County Circuit Court challenging the portion of the 1995 Order that authorized PGE to recover a return on its remaining undepreciated investment in Trojan.

In April 1996, the Marion County Circuit Court issued a decision that contradicted the Court s November 1994 ruling. The 1996 decision found that the OPUC could not authorize PGE to collect a return on its undepreciated investment in Trojan. The 1996 decision was appealed to the Oregon Court of Appeals, where it was consolidated with the earlier appeal of the 1994 decision.

In June 1998, the Oregon Court of Appeals ruled that the OPUC does not have the authority to allow PGE to recover a rate of return on its undepreciated investment in Trojan, but upheld the OPUC s authority to allow PGE s recovery of its undepreciated investment in Trojan and its costs to decommission Trojan (1998 Decision). The court remanded the matter to the OPUC for reconsideration of its 1995 Order in light of the court s decision.

In August 1998, PGE filed a Petition for Review with the Oregon Supreme Court seeking review of that portion of the 1998 Decision relating to PGE s return on its undepreciated investment in Trojan. The URP filed a Petition for Review with the Oregon Supreme Court seeking review of that portion of the 1998 Decision relating to PGE s recovery of its undepreciated investment in Trojan.

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

In March 2002, after a full contested case hearing (Docket UM 989), the OPUC issued an order (Settlement Order) denying all of URP s challenges and approving PGE s application for the accounting and ratemaking elements of the Settlement. URP appealed the Settlement Order to the Marion County Circuit Court.

On November 19, 2002, the Oregon Supreme Court dismissed PGE s and URP s Petitions for Review of the 1998 Decision. As a result, the 1998 Decision stands and the remand of the 1995 Order to the OPUC (1998 Remand) became effective.

In regards to the URP s appeal of the March 2002 Settlement Order, on November 7, 2003, the Marion County Circuit Court issued an opinion remanding the case to the OPUC for action to reduce rates or order refunds (2003 Remand). The opinion does not specify the amount or timeframe of any reductions or refunds. On February 9, 2004, PGE appealed the 2003 Remand to the Oregon Court of Appeals. The OPUC has also appealed.

On March 3, 2004, the OPUC re-opened Dockets DR 10, UE 88, and UM 989 and issued a notice of a consolidated procedural conference before an administrative law judge. On October 18, 2004, the OPUC affirmed the order (Scoping Order) issued by the administrative law judge defining the scope of the proceedings necessary to comply with the orders remanding this matter to the OPUC. The URP and Class Action Plaintiffs (see Dreyer below) filed an application with the OPUC for reconsideration of the Scoping Order, which the OPUC denied. On April 18, 2005, URP and Linda K. Williams filed a complaint in Marion County Circuit Court challenging the OPUC s affirmation of the Scoping Order. On September 21, 2005, the Marion County Circuit Court granted the OPUC s motion to dismiss the complaint.

The OPUC combined the 1998 Remand and the 2003 Remand into one proceeding and is considering the matter in phases. The first phase addresses what rates would have been if the OPUC had interpreted the law to prohibit a return on the Trojan investment. The subsequent phases will address reconciling the results of the first phase with actual rates, and adjusting rates to the extent necessary. A decision is pending in the first phase of the proceeding. On November 15, 2006, PGE filed a motion with the OPUC to Consolidate Phases and Re-Open the Record.

On February 16, 2007, the Oregon Court of Appeals declined to reverse or abate the 2003 Remand and ordered the parties to file revised briefs with the Court of Appeals.

In Order No. 07-157 (the Order) entered on April 19, 2007, the OPUC denied PGE s motion with the OPUC to Consolidate Phases and Re-Open the Record. In addition, the Order abated the Phase I proceeding pending a decision by the Oregon Court of Appeals of the 2003 Remand, and ordered that a second phase of the joint remand proceedings be immediately commenced to investigate the OPUC s delegated authority to engage in retroactive ratemaking. The Order further stated that parties not now participating in the joint remand proceedings will be allowed to intervene and participate in the second phase. Pursuant to the Order, final briefs were submitted on July 20, 2007 and oral argument was held on August 9, 2007, with a decision by the OPUC pending.

On October 10, 2007, the Oregon Court of Appeals issued an opinion that reversed a March 2002 OPUC Order (the 2002 Order) approving the 2000 settlement agreements and remanded the 2002 Order to the OPUC for reconsideration. The Oregon Court of Appeals also vacated the 2003 Remand.

Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company, Marion County Circuit Court, Case No. 03C 10639; and Morgan v. Portland General Electric Company, Marion County Circuit Court, Case No. 03C 10640.

On January 17, 2003, two class action suits were filed in Marion County Circuit Court against PGE on behalf of two classes of electric service customers. The Dreyer case seeks to represent current PGE customers that were customers during the period from April 1, 1995 to October 1, 2001 (Current Class) and the Morgan case seeks to represent PGE customers that were customers during the period from April 1, 1995 to October 1, 2001, but who are no longer customers (Former Class, together with the Current Class, the Class Action Plaintiffs). The suits seek damages of $190 million plus interest for the Current Class and $70 million plus interest for the Former Class, from the inclusion of a return on investment of Trojan in the rates PGE charges its customers.

On April 28, 2004, the plaintiffs filed a Motion for Partial Summary Judgment and on July 30, 2004, PGE also moved for Summary Judgment in its favor on all of the Class Action Plaintiffs claims. On December 14, 2004, the Judge granted the Plaintiffs motion for Class Certification and Partial Summary Judgment and denied PGE s motion for Summary Judgment. PGE filed for an interlocutory appeal, which was rejected on February 1, 2005. On March 3, 2005, PGE filed a Petition for a Writ of Mandamus with the Oregon Supreme Court asking the Court to take jurisdiction and command the trial Judge to dismiss the complaints or to show cause why they should not be dismissed. On March 29, 2005, PGE filed a second Petition for an Alternative Writ of Mandamus with the Oregon Supreme Court seeking to overturn the Class Certification.

On August 31, 2006, the Oregon Supreme Court issued a ruling on PGE s Petitions for Alternative Writ of Mandamus abating these class action proceedings until the OPUC responds to the 2003 Remand.

On October 5, 2006, the Marion County Circuit Court issued an Order of Abatement in response to the ruling of the Oregon Supreme Court, abating the class actions for one year.

On October 17, 2007, the plaintiffs in the class action suits filed a motion with the Marion County Circuit Court to lift the abatement ordered by the Circuit Court in October of 2006. A hearing on that motion is scheduled for April 2008. On January 14, 2008, the class action plaintiffs filed a motion asking the OPUC to issue an order on the OPUC remedial authority prior to addressing the other issues and the Utility Reform Project requested permission to address all issues it previously raised on appeal to the Circuit Court and on cross-appeal to the Court of Appeals in URP, et al. v. PUC, with an opportunity to present new evidence with full evidentiary hearings. On February 13, 2008, the OPUC issued an order denying this motion. In the order, the OPUC expressed its desire to avoid future piecemeal litigation by resolving all of these issues in one comprehensive order, including the issue of the OPUC s remedial authority. The OPUC further stated that it has come to the preliminary conclusion that the OPUC has refund authority under limited circumstances. The OPUC emphasized that this is a preliminary determination and stated that it has not yet determined whether it is necessary to exercise that authority in this case and that it cannot make such a determination until it has decided all phases of the proceedings. On February 22, 2008, the Administrative Law Judge issued a Ruling and Notice of Conference, which established the scope for further proceedings prior to issuance of the OPUC order. The ruling also includes notice of a conference scheduled for March 12, 2008 to establish a procedural schedule for the remainder of this phase of the proceeding.

Wah Chang, a division of TDY Industries, Inc. v. Avista Corporation, Avista Energy, Inc., Avista Power, LLC, Dynegy Power Marketing, Inc., El Paso Electric Company, IDACORP, Inc., Idaho Power Company, IDACORP Energy L.P., Portland General Electric Company, Powerex Corporation, Puget Energy, Inc., Puget Sound Energy, Inc., Sempra Energy, Sempra Energy Resources, Sempra Energy Trading Corp., Williams Power Company, Inc., United States District Court for the District of Oregon, Case No. 04-CV-00619-AS.

On May 5, 2004, Wah Chang, a division of TDY Industries, (Wah Chang) filed a complaint in the U.S. District Court for the District of Oregon against PGE and fifteen other companies (Wah Chang Defendants) alleging that practices among the Wah Chang Defendants and/or Enron and others involving the generation, purchase, sale and transmission of electric energy, beginning in 1998 and continuing through 2001, were designed to communicate false or misleading information to participants in the energy market with the purpose of causing a shortage or appearance of a shortage in the generation of electricity, the appearance of congestion in the transmission of electricity, illegally raising the price of electricity, and fraudulently concealing illegal activities, all in violation of Federal and state antitrust statutes, the Racketeer Influenced and Corrupt Organization Act and for wrongful interference with their purchase contracts with PacifiCorp. No specific facts as to PGE s activities are alleged. Wah Chang seeks compensatory ($30 million) and treble damages.

On February 11, 2005, the Court entered an order dismissing the case based on federal preemption of state law claims, the exclusive jurisdiction of the FERC over electricity markets, and the filed rate doctrine that holds that rates approved by a governing regulatory agency are reasonable and unassailable in judicial proceedings brought by ratepayers. On March 10, 2005, Wah Chang filed a notice of appeal in the Ninth Circuit Court of Appeals, with oral argument held on April 10, 2007.

On November 20, 2007, the Ninth Circuit affirmed the trial court s dismissal of the claims based on the filed rate doctrine. On January 15, 2008, the Ninth Circuit denied Wah Chang s petition for rehearing.

Puget Sound Energy, Inc. v. All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western System Power Pool Agreement, Federal Energy Regulatory Commission, Docket Nos. EL01-10-000, et seq. (Northwest Refund case)

On July 25, 2001, the FERC called for a preliminary evidentiary hearing to explore whether there may have been unjust and unreasonable charges for spot market sales of electricity in the Pacific Northwest from December 25, 2000 through June 20, 2001. During that period, PGE both sold and purchased electricity in the Pacific Northwest. In September 2001, upon completion of hearings, the appointed administrative law judge issued a recommended order that the claims for refunds be dismissed. In December 2002, the FERC re-opened the case to allow parties to conduct further discovery. In June 2003, the FERC issued an order terminating the proceeding and denying the claims for refunds. In November 2003 and February 2004, the FERC denied all requests for rehearing of its June 2003 decision. Parties appealed various aspects of these FERC orders to the U.S. Ninth Circuit Court of Appeals (Ninth Circuit).

On August 24, 2007, the Ninth Circuit issued its decision on appeal, concluding that the FERC failed to adequately explain how it considered or examined new evidence showing intentional market manipulation in California and its potential ties to the Pacific Northwest and that the FERC should not have excluded from the Pacific Northwest refund proceeding purchases of energy made by the California Energy Resources Scheduling (CERS) division in the Pacific Northwest spot market. The Ninth Circuit remanded the case to the FERC to (i) address the new market manipulation evidence in detail and account for it in any future orders regarding the award or denial of refunds in the proceedings, (ii) include sales to CERS in its analysis, and (iii) further consider its refund decision in light of related, intervening opinions of the court. The Ninth Circuit offered no opinion on the FERC s findings based on the record established by the administrative law judge and declined to reach the merits of the FERC s ultimate decision to deny refunds. Two requests for rehearing have been filed with the court, with a decision now pending.

The settlement between PGE and certain other parties in the California refund case in Docket No. EL00-95, *et seq*. (California Refund case), approved by the FERC on May 17, 2007, resolves all claims as between PGE and the California parties named in the settlement as to transactions in the Pacific Northwest during the settlement period, January 1, 2000 through June 21, 2001, but does not settle potential claims from other market participants relating to transactions in the Pacific Northwest.

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In a separate action, on March 20, 2002, the California Attorney General filed a complaint (the Lockyer case) with the FERC against various sellers in the wholesale power market, alleging that the FERC s authorization of market-based rates violated the Federal Power Act (FPA), and, even if market-based rates were valid under the FPA, that the quarterly transaction reports required to be filed by sellers, including PGE, did not contain the transaction-specific information mandated by the FPA and the FERC. The complaint argued that refunds for amounts charged between market-based rates and cost-based rates should be ordered. The FERC denied the challenge to market-based rates and refused to order refunds, but did require sellers, including PGE, to re-file their quarterly reports to include transaction-specific data. The California Attorney General appealed the FERC s decision to the Ninth Circuit. On September 8, 2004, the Court issued an opinion upholding the FERC s authority to approve market-based tariffs, but also holding that the FERC had the authority to order refunds, if quarterly filing of market-based sales transactions had not been properly made. The Court required the FERC, upon remand, to reconsider whether refunds should be ordered. Petitions for rehearing at the Ninth Circuit and for U.S. Supreme Court review have been denied and the case has been remanded to the FERC.

On December 10, 2007, certain California parties filed with the FERC a Motion to hold the Lockyer case remand proceedings in abeyance until the court issues mandates in the California Refund case and Northwest Refund case. In their Motion, the California parties argue that all three cases include similar parties and similar issues, particularly the impact of alleged market manipulation in western energy markets during the 2000-2001 time period. They assert that these cases should be considered together by FERC and that they will file a motion to consolidate all three cases upon remand of the two that remain pending before the Ninth Circuit. The Company and other parties filed answers contesting the California parties characterization of the three cases as inextricably linked and arguing that it is premature to discuss consolidation. Consolidation of the Lockyer case with the Northwest Refund case and the California Refund case could increase the Company s potential liability by extending the period for which other parties are requesting refunds back to May 1, 2000 or earlier.

General

From time to time in the normal course of business, PGE is subject to various other regulatory proceedings, lawsuits, claims and other matters, certain of which may result in adverse judgments, settlements, fines, penalties, injunctions or other relief. Management does not believe any of these other matters will have a material adverse effect on the Company s financial position, results of operations or cash flows.

Item 4. Submission of Matters to a Vote of Security Holders

None.

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Part II

Item 5. Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

PGE common stock is traded on the New York Stock Exchange (NYSE) under the ticker symbol POR . At February 15, 2008, there were 1,335 holders of record of PGE s common stock. Quarterly stock prices since the April 3, 2006 issuance of new PGE common stock are indicated in the table below.

	Price Range		Dividends Declared Per Share
2007 - Quarter	**High**	**Low**	
4	$ 28.45	$ 25.81	$ 0.235
3	28.51	26.43	0.235
2	31.03	26.65	0.235
1	29.81	25.70	0.225
2006 - Quarter			
4	$ 28.65	$ 24.12	$ 0.225
3	26.60	24.25	0.225
2	31.11	24.97	0.225
1*	-	-	-

* Prior to April 3, 2006, PGE s stock was not publicly traded.

PGE expects to pay regular quarterly dividends on its common stock. However, the declaration of such dividends is at the discretion of the Company s Board of Directors and is not guaranteed. The amount of common dividends will depend upon PGE s results of operations and financial condition, future capital expenditures and investments, any applicable regulatory and contractual restrictions, and other factors that the Board of Directors considers relevant.

As required by Section 303A.12 of the NYSE Listed Company Manual, the Chief Executive Officer of the Company certified to the NYSE on May 3, 2007 that she was not aware of any violation by the Company of the NYSE s corporate governance listing standards.

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Item 6. Selected Financial Data

Statement of Income Data:

	For the Years Ended December 31,				
	2007	**2006**	**2005**	**2004**	**2003**
	(In millions, except per share amounts)				
Revenues (a)	$ 1,743	$ 1,520	$ 1,446	$ 1,454	$ 1,752
Income from operations	198	121	126	150	124
Net income	145	71	64	92	60
Earnings per share - basic and diluted	2.33	1.14	1.02	1.48	0.94
Dividends declared per common share	0.93	0.675	*	*	*

Balance Sheet Data:

	December 31,				
	2007	**2006**	**2005**	**2004**	**2003**
	(In millions)				
Total assets	$ 4,108	$ 3,767	$ 3,638	$ 3,403	$ 3,372
Long-term debt (b)	1,313	1,003	890	922	983

(a) On October 1, 2003, PGE adopted EITF 03-11, *Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes as Defined in Issue No. 02-3*, which requires that realized gains and losses associated with non-trading derivative activities that are not physically settled be reported on a net basis. Prior to October 1, 2003, such settlements were recorded on a gross basis in both Revenues and Purchased power and fuel expense. Amounts for periods prior to October 1, 2003 were not reclassified. Accordingly, Revenues for 2003 are not comparable to 2004 through 2007.

(b) Includes preferred stock subject to mandatory redemption requirements, in 2006 and earlier.

* Not meaningful as PGE was a wholly-owned subsidiary of Enron.

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Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation

Information Regarding 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 relate to expectations, beliefs, plans, objectives for future operations, assumptions, business prospects, 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, should, estimates, expects, intends, plans, predicts, projects, will likely continue, or similar expressions identify forward-looking statements.

Forward-looking statements are not guarantees of future performance and involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed. PGE s expectations, beliefs and projections are expressed in good faith and are believed by PGE to have a reasonable basis including, without limitation, management s examination of historical operating trends, 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 assets and facilities, operation and construction of plant facilities, transmission of electricity, recovery of NVPC and other capital investments, and current or prospective wholesale and retail competition;

- the outcome of legal and regulatory proceedings and issues, including the Trojan Investment Recovery and the Pacific Northwest Refunds proceedings, described in Note 14, Contingencies, in the Notes to Consolidated Financial Statements;

- unseasonable weather and other natural phenomena, which, in addition to affecting PGE s customers demand for power, could have a serious impact on PGE s ability and cost to procure adequate supplies of fuel or power to serve its customers;

- operational factors affecting PGE s power generation facilities including outages, unplanned forced outages, hydro conditions, wind conditions, and disruption of fuel supply;

- wholesale energy prices (including the effect of FERC price controls) and their impact on the availability and price of wholesale power in the western United States;

- residential, commercial, and industrial growth and demographic patterns in PGE s service territory;

- future laws, regulations, and proceedings that could result in requirements for additional pollution control equipment or significant emissions fees or taxes, particularly with respect to coal-fired generation facilities, to mitigate carbon dioxide and other gas emissions, including regional haze and mercury emissions, affecting the future operations of the Company s thermal generating plants;

capital market conditions, including interest rate fluctuations, and changes in PGE s credit ratings, which could have an impact on the cost of capital and the ability of PGE to access the

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- capital markets to support requirements for working capital, construction costs, and the repayment of maturing debt;
- the effectiveness of PGE s risk management policies and procedures and the creditworthiness of customers and counterparties;
- the failure to complete major generating plants on schedule and within budget;
- the effects of Oregon law related to utility rate treatment of income taxes (SB 408), which may result in earnings volatility and adverse effects on results of operations;
- changes in, and compliance with, environmental and endangered species laws and policies;
- the effects of global warming or climate change, including changes in the environment that may affect energy costs or consumption and changes in laws or regulations related to greenhouse gas emissions that may increase the Company s costs or affect its operations;
- new federal, state, and local laws that could have adverse effects on operating results;
- employee workforce factors, including aging, potential strikes, work stoppages, and the loss of key executives;
- general political, economic, and financial market conditions;
- the outcome of efforts to relicense the Company s hydroelectric projects, as required by the FERC;
- natural disasters and other natural risks, such as earthquake, flood, drought, lightning, wind, and fire;
- acts of war or terrorism; and
- financial or regulatory accounting principles or policies imposed by governing bodies.

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.

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Overview

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

The Company s revenues and income from operations are subject to fluctuations during the year due to the impacts of seasonal weather conditions on demand for electricity, price changes, customer usage patterns, and the availability and price of purchased power and fuel. PGE is a winter peaking utility that typically experiences its highest retail energy sales during the winter heating season, with a slightly lower peak in the summer that generally results from air conditioning demand.

Customers - As of December 31, 2007, the Company served approximately 804,000 retail customers, a 1.4% increase from the end of 2006. The number of residential and commercial customers both increased during 2007, with total retail energy deliveries up 1.0% for the year. This growth was the result of continued economic expansion, as Oregon s non-farm employment (seasonally adjusted) grew 1.4% in 2007 and the state s 5.3% unemployment rate (seasonally adjusted) was down slightly from 2006.

The Company expects weather adjusted retail loads to increase 1.9% in 2008, with higher commercial demand and increased deliveries to industrial customers, including new solar panel manufacturers, expected to more than offset slower growth in the housing market and lower residential use resulting from conservation and energy efficiency efforts. Customer increases and demand growth will require continued investment in generation, transmission and distribution facilities to meet increased energy requirements.

PGE continues its focus on customer service and recognizes the importance of reliability, restoration response, safety, and reasonable prices in maintaining overall customer satisfaction. As the Company effectively maintains and improves its transmission, distribution, and customer service systems, it continues to place a top priority on meeting regulatory standards for safety and constantly strives to exceed service quality standards related to outage frequency and duration. The Company continues to rank high in surveys of customer satisfaction.

PGE is currently engaged in three major efforts that are expected to benefit customers. First, the Company has a customer focus initiative that seeks to meet rising customer expectations for service and reliability. Second, the Company has signed contracts with vendors for the purchase and installation of an Advanced Metering Infrastructure (AMI) system. Subject to Board of Directors and regulatory approvals, PGE will deploy AMI for residential and commercial customers between 2008 and 2010, with the expectation of achieving operational savings through increased efficiencies while also providing new services for customers. Third, the Company has undertaken an initiative to improve its ability to serve increasing numbers of customers who do business with PGE through the internet.

PGE periodically evaluates the need to change its overall general retail electric price structure to sufficiently cover its operating costs and provide a reasonable rate of return. PGE plans to file new tariffs with the OPUC on February 27, 2008, based on a forecasted 2009 test year, seeking an increase in electricity prices effective January 1, 2009. The proposed 8.9% increase in prices is a result of increased generation costs based on higher natural gas and coal prices; increased purchased power costs; and higher general (non-power) costs, including the rising cost of materials and supplies, government compliance, hydro relicensing improvements, and labor and healthcare benefits. The revenue requirements include a return on common equity of 10.75%, based on an expected capital structure of 50% equity and 50% debt, and an overall weighted average cost of capital of 8.66%. Review of PGE s filing by the OPUC, including a detailed analysis of the Company s projected costs and proposed price structure, is expected to take nine to ten months and will include input from stakeholders.

In May 2007, Residential Exchange Program (REP) payments to the region s investor-owned utilities, including PGE, were suspended as a result of a decision by the U.S. Ninth Circuit Court of Appeals. This program, administered by the Bonneville Power Administration (BPA), provides residential and small farm customers with the benefits of federal power. The removal of exchange program credits from PGE customers bills has resulted in an approximate 14% average price increase for the Company s residential and small farm customers. In February 2008, the BPA issued its initial proposal to re-establish REP payments to investor-owned utilities. For further information, see Results of Operations in this Item 7.

Power Supply - PGE utilizes its own generating resources, along with wholesale market purchases, to meet the energy and capacity needs of its customers. In June 2007, the Company added the 406 MW capacity Port Westward plant to its base of generating resources, reducing its dependence on the wholesale energy market. With the completion of the 125 MW Phase I of Biglow Canyon in late 2007, the Company has a more diverse generation portfolio powered by coal, natural gas, hydro and wind and has further reduced its dependence on purchased power. In addition, PGE has implemented a generation excellence program aimed at ensuring cost-effective and reliable plant operations.

PGE supplements its own generation with short- and long-term wholesale contracts as needed to meet its retail load requirements and provide the most economic mix on a variable cost basis. Factors that can affect the availability and price of purchased power and fuel include weather conditions in the Northwest and Southwest, the performance of major generating facilities in both regions, regional hydro conditions, and prices of natural gas and coal used to fuel thermal generating plants. Market prices of natural gas can also be affected by destructive storms and extreme weather in other regions of the United States. Prices of purchased power, coal, and natural gas trended upward during 2007, due in part to the effect of higher crude oil prices, with the increased coal and natural gas prices resulting in higher overall generation costs.

PGE s 2007 IRP, filed with the OPUC in June 2007, describes the Company s energy and capacity supply strategy to meet the long-term electric energy needs of its customers, with emphasis on supply reliability and price stability. The result of a planning process utilizing input from various stakeholders, the IRP includes additional renewable and demand-side resources, energy efficiency measures, demand-side resources, power purchase agreements of varying terms, and the acquisition of additional peaking capacity. Once the OPUC has officially acknowledged the plan, the Company will issue Requests for Proposals to acquire sufficient resources, including power contracts and asset acquisitions, to meet the future energy and capacity needs of its customers, as outlined in the plan. For further information, see Integrated Resource Plan under Power and Fuel Supply included in Item 1. - Business.

New Renewable Energy Standards adopted by the 2007 Oregon legislature require that PGE and other large electricity providers in Oregon serve at least 25% of their retail load within the state from renewable resources by the year 2025, with interim requirements of 5% by 2011, 15% by 2015, and 20% by 2020. Biglow Canyon, which is expected to have a total installed capacity of 400 to 450 MW when all three phases are completed by the end of 2010, represents a significant step toward the Company s achievement of these goals.

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Legal, Regulatory, and Environmental Matters - PGE is a party in several legal and regulatory proceedings that could have a material impact on the Company s results of operations and cash flows for future periods, including:

- challenges, appeals and reviews on the issue of the OPUC s authority to grant a return on the Company s remaining investment in its closed Trojan plant during the period it ordered PGE to amortize the investment, which the OPUC set in a 1995 general rate order;
- claims for refunds related to wholesale energy sales in the Pacific Northwest during 2000 - 2001; and
- an OPUC order that approved a deferred accounting application that could result in customer refunds of a portion of state and federal income taxes related to the three-month period prior to the January 1, 2006 effective date of the automatic adjustment clause of SB 408.

For further information regarding these and other matters, see Note 14, Contingencies, in the Notes to Consolidated Financial Statements.

PGE is subject to state and federal environmental laws and regulations that establish air quality standards and regulate allowed emissions from thermal generating plants. Such laws and regulations, as well as federal regional haze rules that establish goals to protect visibility and remedy existing impairments resulting from man-made pollution, may affect the Company s operations. While PGE anticipates that it will be able to comply with these restrictions and those imposed under the Clean Air Mercury Rule, such rules will require added costs for additional emission control equipment. In November 2007, the Company submitted to the Oregon DEQ its BART plan for implementing controls to meet the requirements. Final approval of the plan is expected to occur in the second half of 2009. For further information, see Air Quality Standards within Capital Requirements of the Capital Resources and Liquidity section of this Item 7.

The Company has begun construction of a Selective Water Withdrawal structure at its Pelton Round Butte Hydroelectric Project in an effort to restore fish passage on the upper Deschutes River. During 2007, decommissioning of the Bull Run system began with the removal of the Marmot Dam, allowing fish passage on the Sandy River.

In addition, increasing local, national and international concerns regarding global warming and climate change may result in future laws or regulations that require additional pollution control equipment or significant emissions fees or taxes. For further information regarding estimated future capital expenditures related to emission control laws and regulations, see Capital Requirements in Capital Resources and Liquidity in this Item 7.

Financing - PGE maintains adequate liquidity through both its $400 million credit facility and access to the commercial paper market. The Company issued a total of $375 million of First Mortgage Bonds in 2007 to help provide sufficient liquidity to fund ongoing operations and construction projects. Increased capital expenditures expected over the next several years include those related to Phases II and III of Biglow Canyon, hydro relicensing, the AMI project, and requirements of environmental regulations. The Company s ability to execute its capital investment plan will depend on continued strength in the economy and access to capital markets. In anticipation of additional capital needs, the Company recently received authorization from the FERC to increase its short-term borrowing to a total of $550 million and has received approval from the OPUC to issue an additional $250 million of First Mortgage Bonds.

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PGE strives to maintain a common equity ratio (common equity to total consolidated capitalization, including current debt maturities) of approximately 50% in order to maintain acceptable credit ratings and allow access to long-term capital at reasonable rates. PGE s common equity ratio at December 31, 2007 was 50%.

For a discussion of new accounting standards that have been issued but not yet adopted by the Company, see New Accounting Standards within Note 1, Summary of Significant Accounting Policies, in the Notes to Consolidated Financial Statements.

Results of Operations

See Consolidated Statements of Income in Item 8. - Financial Statements and Supplementary Data, for Operating expense detail. The following tables contain certain financial and operating information for the periods presented:

	Years Ended December 31,		
	2007	**2006**	**2005**
Revenues (in millions):			
Retail sales:			
Residential	$ 716	$ 628	$ 593
Commercial	593	547	505
Industrial	159	206	178
Total retail sales	1,468	1,381	1,276
Direct access customers:			
Commercial	-	(6)	1
Industrial	(12)	(6)	-
Total tariff revenues	1,456	1,369	1,277
Regional Power Act credits	42	35	31
Provision for collection (refund) - SB 408	18	(40)	-
Accrued revenue	-	3	(3)
Total retail revenues	1,516	1,367	1,305
Wholesale revenues	201	135	116
Other operating revenues	26	18	25
Total revenues	$ 1,743	$ 1,520	$ 1,446

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	Years Ended December 31,		
	2007	2006	2005
Energy sold and delivered - MWhs (in thousands):			
Retail energy sales:			
Residential	7,688	7,573	7,323
Commercial	7,289	7,319	7,069
Industrial	2,485	3,541	3,148
Total retail energy sales	17,462	18,433	17,540
Delivery to direct access customers:			
Commercial	492	430	400
Industrial	1,673	569	814
Total retail energy deliveries	19,627	19,432	18,754
Wholesale sales	4,042	3,312	2,094
Trading activities	-	-	815
Total energy sold and delivered	23,669	22,744	21,663

	As of December 31,		
	2007	2006	2005
Retail customers:			
Residential	706,444	696,779	685,568
Commercial	97,088	95,734	94,012
Industrial	256	259	257
Total retail customers	803,788	792,772	779,837

2007 Compared to 2006

PGE s net income was $145 million, or $2.33 per diluted share, for the year ended December 31, 2007 compared to $71 million, or $1.14 per diluted share, for the year ended December 31, 2006. The improved results were primarily attributable to increased energy deliveries, increased generation from the return of Boardman to full operation, and the addition of Port Westward. Results for 2006 included a $32 million after-tax impact of incremental power costs required to replace the output of Boardman during its extended repair outage. Results for 2007 include a positive $16 million after-tax impact of the deferral of a portion of the Boardman replacement power costs (including accrued interest) for potential future recovery, as approved by the OPUC.

Also contributing to the increase in earnings was a $35 million after-tax impact from SB 408, with an estimated collection from customers recorded in 2007 compared to a refund recorded in 2006. This positive impact in 2007 reflects in part the so-called double whammy effect of the law that results in unusual outcomes in certain situations. As the provisions of SB 408 apply to PGE, if the Company records higher operating income as compared to its latest rate case, customers would be surcharged for the increase in income taxes, further increasing earnings. Conversely, if the Company records lower operating income as compared to its latest rate case, customers would receive refunds for the decrease in income taxes, further decreasing earnings. For further information, see Note 15, Utility Rate Treatment of Income Taxes, in the Notes to Consolidated Financial Statements.

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Total revenues in 2007 increased $223 million, or 15%, from 2006 as a result of the following factors:

Total retail revenues increased $149 million, or 11%, due primarily to:

- Price increases related to higher power and fuel costs and cost recovery of Port Westward, resulting in an approximate 6.4% increase in annual revenues;
- A $58 million increase related to SB 408, with $18 million in collections recorded in 2007 (consisting of $15 million for the 2007 reporting year and $3 million related to the 2006 reporting year) and a $40 million refund recorded in 2006;
- A 1% increase in total retail energy deliveries, primarily from an approximate 11,500 increase in the average number of customers served in 2007; and
- Price increases resulting from changes under the Residential Exchange Program due to the discontinuance of subscription power benefits (fully offset by increased purchased power costs) and suspension of cash payments in May 2007.

Lower energy sales to industrial customers resulted from a greater portion of industrial customers choosing direct access and purchasing their energy requirements from an Electricity Service Supplier (ESS). Reduced revenues from these customers reflect the lower energy sales as well as transition adjustment credits, reflecting the difference between the cost and market value of PGE s power supply portfolio, as provided by Oregon s electricity restructuring law.

On a weather adjusted basis, retail energy deliveries to PGE and ESS customers increased 1.1% in 2007, with deliveries to residential, commercial, and industrial customers increasing by 0.7%, 1.0%, and 2.2%, respectively. Increased residential sales resulted primarily from an increase of 10,000 in the average number of customers served during the year. Higher commercial and industrial sales resulted from a 1,500 increase in the average number of customers served. These increases were partially offset by a slowing economy and conservation efforts. PGE forecasts an approximate 1.9% increase in total weather adjusted energy deliveries to PGE and ESS customers in 2008.

Wholesale revenues increased $66 million, or 49%, from 2006 due to:

- A $36 million, or 22%, increase in energy sales; and
- A $30 million, or 22%, increase in average sales price, related to higher natural gas prices and lower regional hydro availability.

Other operating revenues increased $8 million, or 44%, primarily as the result of increased gains from the sale of natural gas in excess of generating plant requirements.

The following price adjustments, as approved by the OPUC, became effective on January 1, 2008:

Biglow Canyon - An approximate 0.6% average price increase for cost recovery of Phase I of Biglow Canyon, which was commissioned in December 2007. The increase is net of savings resulting from a Strategic Investment Program that was executed with Sherman County, Oregon, where Biglow Canyon is located, that provides for property tax relief for a period of fifteen years, which will be passed along to customers; and

Annual Power Cost Update Tariff - An approximate 0.3% price decrease for changes in forecasted power and fuel costs. The approved tariff establishes a new baseline NVPC for purposes of the PCAM calculation for 2008.

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The above items, combined with other miscellaneous tariff changes totaling an approximate 0.5% increase, will result in an overall increase of approximately 0.8% in average prices for 2008.

Pending regulatory matters that could have an effect on customer prices and future revenues include the following:

Residential Exchange Program (REP) - In May 2007, the BPA suspended REP payments to investor-owned utilities, including PGE, as a result of a decision by the U.S. Ninth Circuit Court of Appeals. The removal of exchange program credits from PGE customers bills has resulted in an approximate 14% average price increase for the Company s residential and small farm customers. In February 2008, the BPA issued its initial proposal to re-establish REP payments to investor-owned utilities. Payments would begin in late 2008 and include $210 million ($46 million to be credited to PGE customers) related to BPA s 2009 fiscal year, which begins October 1, 2008.

BPA has also determined that actual REP payments made from 2002 through May 2007 under certain settlement agreements exceeded those which should have been made under terms of traditional REP agreements covering the period 2002 through 2011. In its initial proposal BPA stated that such agreements would have utilized a calculation method that would have resulted in lower payments than those actually made by BPA. The BPA proposal includes recovery of $620 million of such overpayment ($64 million from PGE customers) over the period of 2009 through 2028. The recovery will reduce future REP payments to investor-owned utilities.

Energy Efficiency Tariffs - On October 26, 2007, PGE filed proposed tariffs with the OPUC to implement demand-side programs outlined in the Company s 2007 IRP. The Company has requested to extend the proposed effective date of the tariffs from January 1, 2008 to June 1, 2008. If approved, the tariffs would provide an additional $14 million to the ETO and would result in certain incremental customer service expenses related to the achievement of energy savings targets.

Boardman Deferral Amortization - On October 9, 2007, PGE filed a request with the OPUC to amortize the deferral of $26.4 million of replacement power costs, plus interest until the amortization period begins (accrued interest is $5.0 million as of December 31, 2007), associated with the outage of Boardman from November 18, 2005 through February 5, 2006. In its filing, the Company proposed that the amortization be offset with certain credits due to customers, with no price impact anticipated. PGE s request is subject to both a prudency review with respect to the outage and to a regulated earnings test.

AMI - PGE is seeking OPUC approval of a new tariff that includes an approximate $13 million increase in annual revenue requirements to recover the cost of the AMI project, including recovery of the undepreciated cost of existing meters. The proposed tariff would run for approximately two and a half years, coinciding with the period over which PGE completes systems acceptance testing and installation of the new meters, expected to begin in mid-2008, subject to OPUC approval.

Customer refunds (SB 408) - PGE filed its report on October 15, 2007 with the OPUC reflecting the amount of taxes paid by the Company for the 2006 reporting year, as well as the amount of taxes authorized to be collected in rates. The report is being reviewed as part of a formal process, with the OPUC expected to issue an order in April 2008. The Company has reached agreement with OPUC Staff and certain interveners that the appropriate refund due customers is $37.2 million plus accrued interest, based on the OPUC s administrative rules that govern the calculation of the refund amount. Under OPUC rules, refunds to customers for the 2006 reporting year will begin on June 1, 2008.

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PCAM - In 2007, PGE recorded a regulatory liability of $16.5 million, including accrued interest, under the PCAM for potential refund to customers. The amount is subject to review by the OPUC and is expected to be included in future prices over a period that has yet to be determined.

In December 2007, the OPUC issued an order that provides an automatic adjustment clause for renewable resources that are expected to be placed in service in the current year. PGE would need to file by April 1 of each year proposed prices to be effective January 1 of the following year. Costs of the eligible resources would earn a return based on the latest authorized cost of capital until added to rate base in PGE s next general rate case filing.

Purchased power and fuel expenses for 2007 increased $116 million, or 15%, from 2006. The following table indicates PGE s total system load (including both retail and wholesale) for the last two years.

	Megawatt-Hours (in thousands)	
	2007	**2006**
Generation	10,403	7,209
Term purchases	10,898	13,582
Spot purchases	1,379	2,229
Total system load	22,680	23,020

The average variable power cost of the above total system loads was $39.19 per MWh in 2007 and $33.65 per MWh in 2006. Averages exclude the effect of amounts related to regulatory power cost deferrals, unrealized gains on derivative instruments, and wholesale credit provisions.

The increase in Purchased power and fuel expense was due primarily to the following factors:

A $101 million increase related to increased thermal generation, which displaced higher-cost electricity purchases in the wholesale market. Increased generation was related primarily to operation of PGE s new Port Westward plant during the last half of 2007 and full-year operation of Boardman, which was closed for repairs in the first half of 2006;

A $95 million increase related to settled natural gas swap agreements entered into in conjunction with PGE s management of its net power costs. These agreements are among those financial instruments in the Company s diversified power supply portfolio used to manage market risk, with activities reflected in Wholesale revenues, Purchased power and fuel expense, and Other operating revenues. See Commodity Price Risk in Item 7A. - Quantitative and Qualitative Disclosures About Market Risk, for further information;

A 12% increase in the average cost of purchased power, resulting in an approximate $58 million increase to expense;

$16 million that has been recorded for future refund to customers under the PCAM, based upon the difference between NVPC as determined by the PCAM and those forecasted and included in retail prices. PGE s NVPC as determined by the PCAM for 2007 was less than the established baseline by $29.4 million. Under the PCAM, 90% of the difference between the $29.4 million and the deadband threshold of $11.7 is to be refunded to customers;

Unrealized gains on derivative activities of $5 million in 2006. Results of these activities are fully deferred in 2007 as a result of the OPUC s approval of the PCAM; and

Discontinuance of subscription power benefits under the Residential Exchange Program (fully offset by increased revenues, with no net income effect).

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Partially offsetting the above increases were:

A 22% decrease in electricity purchases, related primarily to an increase in lower cost thermal generation, resulting in an approximate $136 million reduction to 2007 expense;

An increase of $14.4 million in the deferral, for future recovery, of excess Boardman power costs (approved by the OPUC in February 2007), resulting in a reduction to 2007 expense; and

A $5 million reduction in the Company s wholesale credit reserve, related primarily to the settlement with certain California parties involving wholesale energy transactions in 2000-2001, resulting in a reduction to 2007 expense.

Generation activities - In 2007, PGE generated 56% of its retail load requirement compared to 37% in 2006. Short- and long-term purchases were utilized to meet the remaining load. The Company met 46% of its retail load requirement from thermal generation in 2007 compared to 27% in 2006. PGE- owned hydro generation met 10% of PGE s retail load requirement in both 2007 and 2006.

The addition of Port Westward in June 2007 and the full-year operation of Boardman combined to increase thermal production by 65% in 2007, resulting in reduced reliance on higher cost purchases in the wholesale market.

Partially offsetting the increase in thermal production was a 10% decrease in Company-owned hydro production, resulting from lower stream flows. PGE has long-term agreements to purchase power generated from hydro facilities on the mid-Columbia River. Energy received under these agreements increased 3% in 2007.

Current forecasts indicate that regional hydro conditions in 2008 will be near normal levels. Volumetric water supply forecasts for the Pacific Northwest region, prepared by the Northwest River Forecast Center in conjunction with the Natural Resources Conservation Service and other cooperating agencies as of February 14, 2008 indicate the April-to-September 2008 runoff forecast compared to the actual runoffs for 2007 and 2006, as follows:

Location	2008 Forecast	2007 Actual	2006 Actual
Columbia River at The Dalles, Oregon	102%	97%	107%
Mid-Columbia River at Grand Coulee, Washington	101%	102%	101%
Clackamas River	126%	100%	92%
Deschutes River	106%	91%	100%

Production, distribution, administrative and other expenses increased $30 million, or 10%, in 2007 compared to 2006, due to the following factors:

A $19 million increase in employee benefits (including incentive compensation and medical costs) and customer support expenses;
Operating costs at the new Port Westward plant of $6 million;
A $3 million increase in labor costs; and
A $2 million increase related to maintenance activities at Boardman and Colstrip.

Depreciation and amortization expenses decreased $38 million, or 17%, from 2006 due primarily to the net effect of the following factors:

A $27 million decrease resulting primarily from reductions in depreciation rates for utility plant assets and the authorized recovery of Trojan decommissioning costs, both of which became effective in January 2007 pursuant to the OPUC order in PGE s general rate case;

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A $13 million decrease in the amortization of regulatory assets (fully offset within Income from operations due to a corresponding decrease in Revenues);

A reduction in the deferral of certain tax credits for future ratemaking treatment, resulting in an approximate $2 million decrease to expense; and

A $7 million increase related to the new Port Westward plant, Biglow Canyon, and other capital additions during 2007.

Taxes other than income taxes increased $5 million, or 7%, in 2007 primarily due to:

A $3 million increase in city franchise fees resulting from customer price increases during the year; and

A $2 million increase in property taxes resulting from higher assessed property values.

Income taxes increased $33 million, or 87%, in 2007, due primarily to higher taxable income for the year.

Other income increased $2 million, or 11%, in 2007 due primarily to the net effect of the following factors:

A $5 million interest income accrual (retroactive to January 2006) on $26.4 million of excess power costs associated with Boardman s repair outage, which has been deferred for future recovery, as approved by the OPUC;

A 2006 expense of $5 million related to a loss provision on a non-utility asset and the write-off of certain software costs;

A $1 million increase in interest income related to future customer collections for the 2007 tax year, under the provisions of SB 408;

A $4 million increase in non-utility income taxes associated with the above items; and

A $3 million decrease in income from non-qualified benefit plan trust assets.

Interest expense increased $5 million, or 7%, in 2007, primarily due to a higher level of outstanding long-term debt resulting from the issuance of additional First Mortgage Bonds during the year.

2006 Compared to 2005

PGE s net income was $71 million, or $1.14 per diluted share, for the year ended December 31, 2006 compared to $64 million, or $1.02 per diluted share, for the year ended December 31, 2005. The improved results were primarily attributable to higher energy sales, resulting from both an increase in customers served and weather conditions, and increased hydro availability, resulting from improved stream flows. Results for 2006 also included a $26 million after-tax reserve for a potential refund obligation to customers, reflecting the Company s estimate of the impact of SB 408. In addition, 2006 results reflect a $4 million after-tax decrease in earnings related to the higher cost of incremental replacement power during the extended, unplanned repair outage at Boardman. Results for 2005 include a $6 million after-tax provision related to the refund to customers of previously collected local income taxes.

Total revenues increased $74 million, or 5%, in 2006 from 2005 as a result of the following factors:

Total retail revenues increased $62 million, or 5%, due to the net effect of the following factors:

- A 3.7% average price increase related to higher power and fuel costs;

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- A 3.6% increase in total retail energy deliveries, resulting primarily from an approximate 13,500 increase in the average number of customers served during the year;
- A $40 million decrease related to SB 408, with an estimated customer refund reserve recorded in 2006. For further information, see Note 15, Utility Rate Treatment of Income Taxes, in the Notes to Consolidated Financial Statements;
- A $26 million reduction in the collection of regulatory assets (fully offset in Income from operations due to a corresponding decrease in Depreciation and amortization expense); and
- A $13 million decrease related to transition adjustment credits provided to direct access customers, reflecting the difference between the cost and market value of PGE s power supply portfolio, as provided by Oregon s electricity restructuring law.

Weather adjusted retail energy deliveries to PGE customers, including those purchasing energy from an ESS, increased 2.7% in 2006 compared to 2005, with deliveries to residential, commercial and industrial customers increasing by 2.4%, 3.0% and 2.6%, respectively.

Wholesale revenues increased $19 million, or 16%, primarily due to the net effect of the following factors:

- A 58% increase in energy sales; and
- A 26% reduction in average sales price, resulting from increased regional hydro availability.

Other operating revenues decreased $7 million, or 28%, as the result of 2006 losses from the sale of natural gas in excess of generating plant requirements.

Purchased power and fuel expenses increased $92 million, or 14%, in 2006 from 2005 as a result of the following factors:

Higher power purchases required to meet a 10% increase in total system load requirement;
An increase in the cost of replacing coal-fired generation at Boardman; and
Higher wholesale prices.

The following table indicates PGE s total system load (including both retail and wholesale) for the years 2006 and 2005.

	Megawatt-Hours (in thousands)	
	2006	**2005**
Generation	7,209	7,821
Term purchases	13,582	11,705
Spot purchases	2,229	1,361
Total system load	23,020	20,887

The average variable power cost of the above total system loads was $33.65 per MWh in 2006 and 31.34 per MWh in 2005. Averages exclude the effect of amounts related to regulatory power cost deferrals, unrealized gains on derivative instruments, and wholesale credit provisions.

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Generation activities - In 2006, PGE generated 37% of its retail load requirement compared to 42% in 2005. Short- and long-term purchases were utilized to meet the remaining load. The Company met 27% of its retail load requirement from thermal generation and 10% from hydro generation in 2006 compared to 34% and 8%, respectively, in 2005.

A 17% reduction in thermal production, related primarily to Boardman s outage from late October 2005 through June 2006, resulted in increased reliance on higher cost purchases in the wholesale market.

Partially offsetting the decrease in thermal production was a 28% increase in Company-owned hydro production, resulting from increased stream flows. Energy received under long-term agreements to purchase power from hydro facilities on the mid-Columbia River increased 13% in 2006 compared to 2005.

Production, distribution, administrative and other expenses increased $8 million, or 3%, in 2006 compared to 2005 primarily due to increased expenses related to maintenance and repair activities at PGE s thermal generating plants, storm-related service restoration costs, and increased tree trimming costs. Such increases were partially offset by reduced administrative and other expenses, related primarily to the settlement of certain asserted claims in 2005.

Depreciation and amortization expenses decreased $14 million, or 6%, in 2006 compared to 2005 due primarily to the net effect of the following factors:

- A $26 million decrease in amortization of regulatory assets (fully offset in Income from operations due to a corresponding decrease in Revenues);
- A $6 million increase in depreciation of transmission and distribution plant, due to higher plant balances in 2006;
- A $2 million increase in the deferral of certain tax credits;
- A $2 million increase in amortization of computer software; and
- A $2 million increase in other amortization, including amortization of hydro relicensing costs.

Income taxes decreased $8 million, or 17%, primarily due to lower taxable income and a reduction in state income taxes resulting from apportionment rule changes.

Other income increased $13 million in 2006 compared to 2005 due to the net effect of the following factors:

- A $10 million reserve established in 2005 for the refund to Multnomah County customers of previously collected income taxes;
- An $8 million increase in the allowance for equity funds used during construction, related primarily related to Port Westward; and
- A $3 million decrease in interest income on regulatory assets, due to declining balances as amounts are recovered from customers.

Interest expense increased $1 million, or 1%, in 2006 compared to 2005, primarily due to a higher level of outstanding long-term debt resulting from the issuance of additional First Mortgage Bonds during 2006.

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Capital Resources and Liquidity

Capital Requirements

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

	2008	2009	2010	2011	2012
Ongoing capital expenditures (a)	$ 229	$ 210 - 230	$ 215 - 235	$ 240 - 260	$ 225 - 245
Biglow Canyon -					
Phases II and III (b)	121		$ 500 - 600		
Hydro relicensing	55		$ 105 - 115		
Advanced Metering Infrastructure (c)	23		$ 100 - 110		
Boardman emissions controls (d)	-		$ 230 - 240		
Total capital expenditures	$ 428				
Long-term debt maturities	$ -	-	$ 186	-	$ 100

(a) Upgrades to transmission, distribution and existing generation, as well as new customer connections.
(b) Phases II and III timing subject to turbine availability and project economics.
(c) Under review by OPUC.
(d) See Air Quality Standards, below, for further discussion of emission controls.

Biglow Canyon - In accordance with PGE s plan to acquire additional wind generation, as outlined in its IRP, the Company is proceeding with construction of Biglow Canyon, located in Sherman County, Oregon.

Phase I of the project, with an installed capacity of 125 MW and a cost of $255 million (including AFDC), has been completed. Phases II and III of the project are currently in the advanced planning stages. In the second quarter of 2007, PGE paid $17 million to a vendor towards wind turbines for Phases II and III. The payment is non-refundable if PGE and the vendor do not execute a definitive agreement after good faith efforts to negotiate and execute such an agreement within a specified time period. The payment will be returned to PGE if the vendor fails to negotiate the definitive agreement in good faith. The estimated total cost of Phases II and III is $700 million to $800 million, including approximately $50 million AFDC, with Phase II expected to be completed by the end of 2009 and Phase III expected to be completed by the end of 2010. The cost of the project could vary depending upon the fluctuations of foreign currencies against the U.S. dollar. Total installed capacity of all three phases is expected to be between 400 and 450 MW.

Hydro relicensing - As required under the 50-year license that the FERC issued to PGE in 2004 for its Pelton/Round Butte project on the Deschutes River, PGE began construction of a selective water withdrawal system in late 2007 in an effort to restore fish passage on the upper portion of the river. The system will collect juvenile salmon and steelhead, allowing them to bypass the dam when migrating to the Pacific Ocean, and will regulate downstream water temperature. Completion of the system, at a total cost of approximately $105 million to $110 million, is expected in 2009. PGE s portion of the costs is expected to be approximately $80 million, including AFDC.

Advanced Metering Infrastructure - PGE plans to install, subject to OPUC approval, over 800,000 new customer meters that would enable daily, two-way remote communications with the Company. AMI, at an estimated capital cost of $130 million to $135 million, is expected to provide improved services, operational efficiencies, and a reduction in future expenses.

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Air Quality Standards - In accordance with new federal regional haze rules aimed at visibility impairment in several federally protected areas, the DEQ is conducting an assessment of emission sources pursuant to a BART process. Several other states are conducting a similar process. Those sources determined to cause, or contribute to, visibility impairment at protected areas will be subject to a BART Determination.

In addition, the federal government and the states in which PGE operates have adopted the following regulations concerning mercury emissions:

- In May 2005, the EPA adopted the Clean Air Mercury Rule that establishes a cumulative total (cap) of mercury emissions from all electric generating plants in the United States and assigns to each state a mercury emissions budget.

- The Montana Board of Environmental Review adopted final rules on mercury emissions from coal-fired generating units in Montana, including Colstrip, which set strict mercury emission limits by 2010.

- In December 2006, the Oregon Environmental Quality Commission adopted the Utility Mercury Rule, which requires installation of mercury control technology at Boardman that would reduce the plant s mercury emissions by 90% by July 1, 2012.

- In February 2008, the U.S. Court of Appeals for the District of Columbia Circuit published a unanimous decision vacating both the EPA s rule delisting coal- and oil-fired electric generating units from regulation under § 112 of the CAA and the Clean Air Mercury Rule. The Oregon Utility Mercury Rule was not directly affected by this decision; however, it contains significant components of the federal Clean Air Mercury Rule and thus it is reasonably likely that amendments will be required if the District of Columbia Circuit decision is not overturned.

In response to the EPA s regional haze rules, the Company volunteered to participate in a DEQ pilot project to analyze information about air emissions from Boardman. An exemption modeling analysis for identified sources, which began in September 2006, has indicated that the Boardman and Beaver generating plants may cause or contribute to visibility impairment in several federally protected areas. In November 2007, the Company submitted a BART Determination to the DEQ for Boardman that stated the BART for Boardman is a combination of New Low NO_x Burners, Modified Over Fire Air System, SNCR, and Semi-dry Flue Gas Desulphurization, and that mercury emission regulations should be addressed through a Mercury Sorbent Injection System. The total cost for these controls is estimated to be in the range of $300 million to $400 million (100% of total costs). While the Company believes that these controls meet BART requirements, the regulatory agencies could require Selective Catalytic Reduction rather than SNCR, which would increase the total estimated cost to a range of $470 million to $620 million (100% of total costs). The Company has no commitments in place at this time and cautions that the cost estimates are preliminary and subject to change. Final approval of the plan is expected to occur in the second half of 2009.

As the regulatory requirements are clarified by the relevant agencies and the related costs more closely estimated, the Company will further evaluate the economic prudency of these expenditures. In doing so, the Company will also consider additional costs such as taxes, emission fees and other costs that may be imposed under any future laws related to climate change. Such additional costs, as well as the requirement to install Selective Catalytic Reduction controls, could require an investment in excess of what the plant can economically support.

The ultimate impact that the above regulatory requirements and air emission controls will have on future operations, costs, or generating capacity of the Company s thermal generating plants is not yet determinable. PGE will seek to recover its share of any associated costs through the ratemaking process.

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On January 15, 2008, PGE received a notice of intent to sue from a coalition of environmental groups. The notice alleges violations of the Clean Air Act and the Oregon State Implementation Plan relating to the Boardman generation facility. The Company has not yet fully evaluated the claims referenced in the notice and cannot determine at this time its estimated exposure, if any. If the plaintiffs file their complaint and articulate their claims in greater detail, PGE will be better able to assess the likelihood, if any, that the claims will have a material adverse effect on the Company.

Transmission improvements - PGE and seven other utilities have initiated WECC Coordinated Planning and Technical Studies related to eight significant new high voltage transmission projects currently under consideration in the northwestern United States. The sponsors anticipate completion of the WECC Phase I Rating Studies by August 2008. The Southern Crossing Project, proposed by PGE, would expand the Company s transmission system across the Oregon Cascades with the construction of a new 500 kV transmission line. The project is designed to integrate existing Boardman and Coyote Springs generation resources, integrate up to 750 MW of proposed wind generation resources, and provide additional transmission capacity for future needs.

Liquidity

PGE s access to short-term debt markets provides sufficient liquidity to support current operating activities, including the purchase of electricity to meet load requirements and fuel for the Company s thermal generating plants. Long-term capital requirements are driven largely by expenditures for distribution, transmission, and generation facilities to support both new and existing customers, as well as debt retirement. PGE s liquidity and capital requirements can also be significantly affected by other working capital needs, including margin deposits related to wholesale trading activities, which can vary depending upon the Company s forward positions and the corresponding price curves.

PGE has performed an assessment of its investments held in trusts, which will be used to satisfy future obligations under the Company s pension and postretirement benefit plans and to satisfy future obligations to decommission its Trojan nuclear plant. The Company has determined that a decline in the fair value of its investments that may have subprime-related exposures would not be material.

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

	Years Ended December 31,		
	2007	**2006**	**2005**
Cash and cash equivalents, beginning of year	$ 12	$ 122	$ 204
Cash flows provided by (used in):			
Operating activities	344	106	372
Investing activities	(451)	(380)	(272)
Financing activities	168	164	(182)
Increase (decrease) in cash and cash equivalents	61	(110)	(82)
Cash and cash equivalents, end of year	$ 73	$ 12	$ 122

Cash Flows from Operating Activities - The $238 million increase in cash provided by operating activities in 2007 compared to 2006 was primarily attributable to:

A $115 million decrease in margin deposits with certain wholesale customers, due in part to the Boardman repair outage in 2006;

A $55 million decrease in income tax payments due to the payment of final taxes to PGE s former parent in 2006;

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A $33 million decrease in power purchases, due to the 2006 purchase of replacement power during Boardman s extended repair outage; and

A $28 million cash payment received from the California Power Exchange resulting from a settlement related to wholesale energy transactions in 2000-2001.

A significant portion of cash provided by operations consists of the recovery in revenue requirements of non-cash charges for depreciation and amortization related to utility plant. The $38 million reduction of these charges in 2007 was due primarily to reduced depreciation rates and authorized recovery of Trojan decommissioning costs, as approved by the OPUC in PGE s general rate case. The Company estimates recovery of depreciation and amortization charges to be approximately $210 million in 2008. Combined with all other sources, cash provided by operations is estimated to be approximately $380 million during 2008.

Cash Flows from Investing Activities - Cash flows from investing activities consist of new construction and improvements to PGE s distribution, transmission, and generation facilities. The $71 million increase in cash used in investing activities was primarily attributable to the net effect of:

A $169 million increase in expenditures for construction of Biglow Canyon;
A $108 million reduction in construction costs for Port Westward due to the completion of construction in early 2007; and
Increased expenditures related to the expansion of PGE s distribution system to support both new and existing customers within the Company s service territory.

The Company plans $428 million in total capital expenditures in 2008 related to Phases II and III of Biglow Canyon, hydro relicensing, ongoing capital expenditures and AMI.

Cash Flows from Financing Activities - Cash flows from financing activities provide supplemental cash for both operating and capital requirements. Cash provided by financing activities in 2007 was primarily attributable to the net effect of the following:

Issuance of $375 million of First Mortgage Bonds, at a rate of approximately 5.8%, for general corporate purposes, capital expenditures and repayment of existing debt;
Remarketing of $5.8 million of variable interest rate Port of Morrow Pollution Control Bonds;
Repayment of $81 million in short-term debt;
Payment of $58 million of common stock dividends;
Redemption of $50 million of 7.15% First Mortgage Bonds at maturity;
Redemption of remaining $16 million of 7.75% Series Cumulative Preferred Stock; and
Early redemption of $5.1 million of 7 1/8 % Port of St. Helens Pollution Control Bonds due in 2014.

PGE has received approval from the FERC to increase its short-term borrowings up to a total of $550 million through February 6, 2010, and has received approval from the OPUC to issue an additional $250 million in long-term debt.

Dividends on Common Stock

The following table indicates common stock dividends declared in 2007:

Declaration Date	Record Date	Payment Date	Dividends Declared per Common Share
February 22, 2007	March 26, 2007	April 16, 2007	$0.225
May 2, 2007	June 25, 2007	July 16, 2007	0.235
August 2, 2007	September 25, 2007	October 15, 2007	0.235
October 25, 2007	December 26, 2007	January 15, 2008	0.235

PGE expects to pay regular quarterly dividends on its common stock; however, the declaration of such dividends is at the discretion of the Company s Board of Directors and is not guaranteed. The amount of common dividends is dependent upon PGE s results of operations and financial condition, future capital expenditures and investments, any applicable regulatory and contractual restrictions, and other factors that the Board of Directors considers relevant. On February 20, 2008, the Board of Directors declared a dividend of $0.235 per share of common stock to stockholders of record on March 25, 2008, payable on or before April 15, 2008.

Debt and Equity Financings

PGE has a $400 million five-year revolving credit facility with a group of commercial and investment banks that supplements operating cash flow and provides a primary source of liquidity. The facility, which expires in 2012 and is unsecured, is used as backup for commercial paper borrowings and is available for general corporate purposes, with the maximum amount available to PGE for borrowings and/or the issuance of standby letters of credit.

PGE s ability to secure sufficient long-term capital at a reasonable cost is determined by its financial performance and outlook, capital expenditure requirements, and alternatives available to investors. The Company s ability to obtain and renew such financing depends on its credit ratings as well as on bank credit markets, both generally and for electric utilities in particular. Management believes that the availability of the credit facility and the expected ability to issue long-term debt and equity securities provide sufficient liquidity to meet the Company s anticipated capital and operating requirements. The Company anticipates issuing a total of approximately $300 million debt and $200 million equity in 2008 and 2009.

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 current debt maturities) of approximately 50%. Achievement of this objective while sustaining sufficient cash flow is necessary to maintain acceptable credit ratings and allow access to long-term capital at attractive interest rates. PGE s common equity ratios were 50% and 53% at December 31, 2007 and December 31, 2006, respectively.

For further information regarding PGE s credit facility and debt financing activities, see Note 9, Credit Facility and Debt, in the Notes to Consolidated Financial Statements.

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 (S&P). PGE s current credit ratings and outlook are as follows:

	Moody s	**S&P**
First Mortgage Bonds	Baa1	A
Senior unsecured debt	Baa2	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 counterparties to post additional performance assurance collateral. On December 31, 2007, PGE had posted approximately $33 million of collateral, consisting of $28 million in cash and $5 million in letters of credit, none of which is affiliated with master netting agreements. Based on the Company s energy portfolio, estimates of current energy market prices, and the current level of collateral outstanding, as of

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December 31, 2007, the approximate amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is approximately $55 million and decreases to approximately $8 million by December 31, 2008. The approximate amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade is approximately $83 million and decreases to approximately $8 million by December 31, 2008.

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.

The issuance of additional First Mortgage Bonds requires that PGE meet earnings coverage and security provisions set forth in the Company s Amended and Restated Articles of Incorporation and the Indenture of Mortgage and Deed of Trust securing the bonds. PGE estimates that on December 31, 2007 it could issue up to approximately $601 million of First Mortgage Bonds under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust. Any issuances would be subject to market conditions and amounts may be further limited by regulatory authorizations or by covenants and tests contained in other financing agreements. PGE also has the ability to release property from the lien of the Indenture of Mortgage and Deed of Trust on the basis of property additions, bond credits, and/or deposits of cash.

PGE s credit facility contains customary covenants and credit provisions, including a requirement that limits consolidated indebtedness, as defined in the facility, to 65% of total capitalization. At December 31, 2007, the Company s consolidated indebtedness to total capitalization ratio, as calculated under the facility, was 50%.

Contractual Obligations and Commercial Commitments

The following indicates PGE s contractual obligations as of December 31, 2007 (in millions):

	Payments Due*						
	Total	2008	2009	2010	2011	2012	There-after
Long-term debt	$ 1,313	$ -	$ -	$ 186	$ -	$ 100	$ 1,027
Interest on long-term debt	1,490	81	81	70	67	67	1,124
Operating leases	257	8	7	7	7	8	220
Purchase obligations	171	94	54	11	10	1	1
Purchased power and fuel:							
Electricity purchases	1,341	350	161	75	74	63	618
Capacity contracts	191	23	23	23	23	23	76
Natural gas agreements	194	63	24	23	18	15	51
Public Utility Districts	86	8	9	7	7	5	50
Coal and transportation agreements	30	15	3	3	3	3	3
Total	$ 5,073	$ 642	$ 362	$ 405	$ 209	$ 285	$ 3,170

* Future interest on long-term debt is calculated based on the assumption that all debt remains outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at December 31, 2007. Contributions to the Company s pension plan are estimated at zero for 2008 through 2012 and not determinable thereafter.

Other Financial Obligations

PGE has entered into long-term power purchase contracts with certain public utility districts in the state of Washington under which PGE has acquired a percentage of the output (Allocation) of four hydroelectric projects (the Rocky Reach, Priest Rapids, Wanapum and Wells hydroelectric projects).

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The Company is required to pay its proportionate share of the operating and debt service costs of the projects whether or not they are operable. The contracts further provide that, should any other purchaser of output default on payments as a result of bankruptcy or insolvency, PGE would be allocated a pro rata share of both the output and the operating and debt service costs of the defaulting purchaser. For the Rocky Reach, Wanapum and Wells projects, PGE would be allocated up to a cumulative maximum of 25% of the defaulting purchaser s percentage Allocation. For the Priest Rapids project, PGE would be allocated up to a cumulative maximum that would not adversely affect the tax exempt status of any outstanding debt.

For details of annual costs by project, including debt service, see Note 9, Commitments and Guarantees, in the Notes to Consolidated Financial Statements.

Off-Balance Sheet Arrangements

PGE is not engaged in any off-balance sheet arrangements through unconsolidated limited purpose entities.

Critical Accounting Policies and Estimates

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

Regulatory Accounting

As a regulated utility, PGE prepares its consolidated financial statements in accordance with the provisions of SFAS 71, *Accounting for the Effects of Certain Types of Regulation*. The application of SFAS 71 results in differences in the timing and recognition of certain revenues and expenses in comparison with businesses in other industries. Under the authority of the FERC and the OPUC, the Company has recorded certain regulatory assets and liabilities at December 31, 2007 in the amount of $304 million and $574 million, respectively, and regulatory assets and liabilities of $351 million and $523 million, respectively, at December 31, 2006. For further information, see Note 1, Summary of Significant Accounting Policies, in the Notes to Consolidated Financial Statements.

PGE is subject to jurisdiction of the OPUC, which reviews and approves the Company s retail rates, ensuring that they provide the Company an opportunity to earn a fair return on its investment. The Company s rates, as authorized by the OPUC, are based on the cost of service and are designed to recover operating expenses and capital costs associated with generation, transmission and distribution assets used to provide regulated service to customers. Although changes in such rates are subject to a formal ratemaking process, it is expected that the OPUC will continue to recognize all prudently-incurred costs and authorize rates that allow for their recovery.

If future recovery of costs ceases to be probable, however, PGE would be required to write off its regulatory assets and liabilities. In addition, if PGE determines that all or a portion of its utility operations no longer meet the criteria for continued application of SFAS 71, the Company would be required to adopt the provisions of SFAS 101, which would require the Company to write off those regulatory assets and liabilities related to operations that no longer meet requirements of SFAS 71. Discontinued application of SFAS 71 could have a material impact on the Company s results of operations and financial position.

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Asset Retirement Obligations

SFAS 143, as interpreted by FASB Interpretation No. 47, requires the recognition of Asset Retirement Obligations (AROs), measured at estimated fair value, for legal obligations related to dismantlement and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. Upon initial recognition of AROs that are measurable, the probability weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted risk-free rate, are recognized as both a liability and as an increase in the capitalized carrying amount of the related long-lived assets. Due to the long lead time involved, a market-risk premium cannot be determined for inclusion in future cash flows. Capitalized asset retirement costs are depreciated over the life of the related asset, with accretion of the ARO liability classified as an operating expense on the Statement of Income. On the Statement of Income, AROs related to Utility plant are included in Depreciation and Amortization expense, with those related to Other property included in Other Income (Deductions). In accordance with requirements of SFAS 143, accumulated asset retirement removal costs that do not qualify as AROs have been reclassified from Accumulated depreciation to Regulatory liabilities on the Consolidated Balance Sheets.

Contingencies

The Company has unresolved legal and regulatory issues for which there is inherent uncertainty with respect to the ultimate outcome of the respective matter. Contingencies are evaluated based on SFAS 5, *Accounting for Contingencies*, using the best information available. In accordance with SFAS 5, a material loss contingency is accrued and disclosed when it is probable that an asset has been impaired or a liability incurred and the amount of the loss can be reasonably estimated. If a range of probable loss is established, the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate. If the probable loss cannot be reasonably estimated, no accrual is recorded, but the loss contingency is disclosed to the effect that it cannot be reasonably estimated. Material loss contingencies are disclosed when it is reasonably possible that an asset has been impaired or a liability incurred. Reserves established reflect management s assessment of inherent risks, credit worthiness, and complexities involved in the collection process. No assurance can be given for the ultimate outcome of any particular contingency.

Price Risk Management

PGE engages in price risk management activities in its electric business, utilizing derivative instruments such as electricity forward, swap, and option contracts and natural gas forward, swap, option, and futures contracts to protect the Company against variability in expected future cash flows due to associated price risk and to minimize net power costs for retail customers. Derivative contracts are accounted for under SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended.

In its January 2007 general rate order, the OPUC approved a new PCAM by which PGE can adjust future rates to reflect a portion of the difference between each year s forecasted and actual NVPC. Effective December 2006, PGE began to apply SFAS 71 to all derivative instruments to reflect the effects of regulation. As a result, a regulatory asset or regulatory liability is recorded to offset changes in fair value of instruments not included in the Resource Valuation Mechanism (RVM). Prior to December 2006, changes in fair value for these instruments were not offset by a regulatory asset or regulatory liability unless those contracts were previously included in rates under the RVM or were expected to be included in future rates under the RVM. Effective January 17, 2007, a new Annual Power Cost Update Tariff replaced the RVM.

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Mark-to-Market

Marking a contract to market consists of reevaluating the market value at the end of each reporting period for the entire term of the contract and recording any change in value (difference between the contract price and current market price) in either earnings or other comprehensive income for the period. Valuation of these financial instruments reflects management s best estimates of market prices, including closing New York Mercantile Exchange (NYMEX) and over-the-counter quotations, time value of money, and volatility factors underlying the commitments.

Determining the fair value of these contracts requires the use of prices at which a buyer or seller could currently contract to purchase or sell a commodity at a future date (termed forward prices). Forward price curves are used to determine the current fair market price of a commodity to be delivered in the future. PGE s forward price curves are created by utilizing actively quoted market indicators received from electronic and telephone brokers, industry publications, NYMEX, and other sources, and are validated using independent publications. Estimates used in creating forward price curves can change with market conditions and can be materially affected by unpredictable factors such as weather and the economy. The difference between PGE s forward price curves and four independently published price curves averages 1%. The difference at any single location, delivery date and commodity is less than 5%.

For purchases and sales of forward physical or financial contracts, the mark-to-market value is the present value of the difference between PGE s contracted price and the forward price multiplied by the total quantity of the contract. For option contracts, a theoretical value is computed using standard financial models that utilize price volatility, price correlation, time to expiration, interest rate and price curves. The mark-to-market of these options is the difference between the premium paid or received and the theoretical value.

Pension Plan

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

PGE s pension discount rate is based on assumptions regarding rates of return on long-term high quality bonds. Assumptions regarding the expected rate of return on plan assets are based on historical and projected average rates of return for current asset classes in the plan investment portfolio. The expected rate of return reflects expected future returns for the portfolio, and was used in determining net periodic pension expense for the year. At December 31, 2007, the plan s assets were comprised of approximately 67% equity securities and 33% debt securities.

Changes in actuarial assumptions can also have a material effect on net periodic pension expense. A 0.25% reduction in the expected long-term rate of return on plan assets would have increased 2007 pension expense by approximately $1.2 million. A 0.25% reduction in the discount rate would have increased 2007 pension expense by approximately $1.5 million.

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Item 7A. Quantitative and Qualitative Disclosures About Market Risk

PGE is exposed to various forms of market risk (including changes in commodity prices, foreign currency exchange rates, and interest rates), as well as to credit risk. These changes may affect the Company s future financial results, as discussed below.

Commodity Price Risk

PGE s primary business is to provide electricity to its retail customers. The Company participates in the wholesale marketplace in order to balance its supply of power to meet the needs of its retail customers, manage risk, and administer its current long-term wholesale contracts. In early 2005, PGE discontinued its trading activities for non-retail purposes, with existing trading transactions settled by December 31, 2005. The Company uses purchased power contracts to supplement its thermal, hydroelectric, and wind generation to respond to fluctuations in the demand for electricity and variability in generating plant operations. In meeting these needs, PGE is exposed to market risk arising from the need to purchase power and to purchase fuel for its natural gas and coal fired generating units. The Company uses instruments such as forward contracts, which may involve physical delivery of an energy commodity; swap agreements, which may require payments to (or receipt of payments from) counterparties based on the differential between a fixed and variable price for the commodity; and options and futures contracts to mitigate risk that arises from market fluctuations of commodity prices.

Gains and losses from instruments that reduce commodity price risks are recognized when settled in Purchased power and fuel expense, or in Wholesale revenue. Valuation of these financial instruments reflects management s best estimates of market prices, including closing NYMEX and over-the-counter quotations, time value of money, and volatility factors underlying the commitments.

PGE actively manages its risk to ensure compliance with its risk management policies. The Company monitors open commodity positions in its energy portfolio using a value at risk methodology, which measures the potential impact of market movements over a one-day holding period using a variance/covariance approach at a 95% confidence interval. The portfolio is modeled using net open power and natural gas positions, with power averaged over peak and off-peak periods by month, and includes all financial and physical positions for the next 24 months, including estimates of retail load and plant generation. The risk factors include commodity prices for power and natural gas at various locations and do not include volumetric variability. Based on this methodology, the average, high, and low value at risk on the Company s energy portfolio in 2007 were $4.7 million, $7.6 million, and $1.6 million, respectively, and in 2006 were $5.7 million, $9.9 million, and $3.3 million, respectively.

PGE s energy portfolio activities are subject to regulation and related costs are recovered in retail prices approved by the OPUC. The timing differences between the recognition of gains and losses on certain derivative instruments and their realization and subsequent recovery in prices are deferred as regulatory assets and regulatory liabilities to reflect the effects of regulation under SFAS 71. As contracts are settled, these deferrals reverse. In PGE s value at risk methodology, no amounts are included for potential deferrals under SFAS 71.

Foreign Currency Exchange Rate Risk

PGE faces exposure to foreign currency risk associated with natural gas forward and swap contracts denominated in Canadian dollars in its energy portfolio. Foreign currency risk is the risk of changes in value of pending financial obligations in foreign currencies that could occur prior to the settlement of

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the obligation due to a change in the value of that foreign currency in relation to the U.S. dollar. PGE monitors its exposure to fluctuations in the Canadian exchange rate with an appropriate hedging strategy.

At December 31, 2007, a 10% change in the value of the Canadian dollar would result in an immaterial change in pre-tax income for transactions that will settle over the next 12 months.

Interest Rate Risk

To meet short-term cash requirements, PGE has established a program under which it may from time to time issue commercial paper for terms of up to 270 days; such issuances are supported by the Company s $400 million five-year unsecured revolving credit facility. Although any borrowings under the commercial paper program subject the Company to fluctuations in interest rates, reflecting current market conditions, individual instruments carry a fixed rate during their respective terms. PGE had no short-term debt outstanding at December 31, 2007.

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

The total fair value and carrying amounts (including current maturities) of PGE s long-term debt are as follows (in millions):

	Total Fair Value	Carrying Amounts by Maturity Date Total	2008	2009	2010	2011	2012	There-after
First Mortgage Bonds	$ 957	$ 970	$ -	$ -	$ -	$ -	$ 100	$ 870
Pollution Control Revenue Bonds *	198	195	-	-	37	-	-	158
Other	158	148	-	-	149	-	-	(1)
Total	$ 1,313	$ 1,313	$ -	$ -	$ 186	$ -	$ 100	$ 1,027

* Interest rates on $142 million of Pollution Control Revenue Bonds are fixed until 2009. In 2009, pursuant to terms of the bond agreements, PGE will re-market the bonds and re-set the interest rate and maturity date up to the year 2033. A 1% increase in the current interest rates would result in an approximate $1.4 million increase in annual interest expense.

For detail of debt by category, see Note 7, Credit Facility and Debt, in the Notes to Consolidated Financial Statements.

Credit Risk

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

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

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receivable related to retail electricity sales are provided for such risk. At December 31, 2007, the likelihood of significant losses associated with credit risk in trade accounts receivable is considered to be remote.

The following table presents PGE s credit exposure for commodity activities and their subsequent maturity as of December 31, 2007. The table reflects credit risk included in accounts receivable and price risk management assets, offset by related accounts payable and price risk management liabilities (dollars in millions):

				Maturity of Credit Risk Exposure					
Rating	Credit Risk Before Collateral	Percentage of Total Exposure	Credit Collateral	2008	2009	2010	2011	2012	There-after
Externally rated:									
Investment grade	$ 114	98%	$ 27	$ 51	$ 18	$ 17	$ 14	$ 12	$ 2
Non-Investment grade	1	1%	1	1	-	-	-	-	-
Internally rated:									
Investment grade	1	1%	-	1	-	-	-	-	-
Total	$ 116	100%	$ 28	$ 53	$ 18	$ 17	$ 14	$ 12	$ 2

Investment Grade includes those counterparties with a minimum credit rating on senior unsecured debt of Baa3 (as assigned by Moody s) or BBB- (as assigned by S&P), and also those counterparties whose obligations are guaranteed or secured by an investment grade entity. Non-Investment Grade includes those counterparties with below investment grade credit ratings on senior unsecured debt. For non-rated counterparties, PGE performs credit analysis to determine an internal credit rating that approximates investment or non-investment grade. Included in this analysis is a review of counterparty financial statements, specific business environment, access to capital, and indicators from debt and capital markets. The credit exposure includes activity for electricity and natural gas forward, swap, and option contracts. Posted collateral may be in the form of cash or letters of credit and may represent prepayment or credit exposure assurance. As of December 31, 2007, there was no posted collateral subject to be returned to a counterparty that is affiliated with master netting agreements.

Omitted from the market risk exposures above are long-term power purchase contracts with certain public utility districts in the State of Washington and with the City of Portland, Oregon. These contracts provide PGE with a percentage share of hydro facility output in exchange for an equivalent percentage share of operating and debt service costs. These contracts expire at varying dates through 2018. Management believes that circumstances that could result in the nonperformance by these counterparties are remote.

Risk Management Committee

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

For further information on price risk management activities, see Note 10, Price Risk Management, in the Notes to Consolidated Financial Statements.

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Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of

Portland General Electric Company

Portland, Oregon

We have audited the accompanying consolidated balance sheets of Portland General Electric Company and subsidiaries (the Company) as of December 31, 2007 and 2006, and the related consolidated statements of income, shareholders equity, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedule listed in Item 15(a). We also have audited the Company s internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company s management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and the financial statement schedule and an opinion on the Company s internal control over financial reporting based on our audits.

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

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

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Portland General Electric Company and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As discussed in Notes 1 and 2 to the consolidate financial statements, on December 31, 2006 the Company changed its method of accounting for defined benefit and other postretirement plans upon the adoption of Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans*.

/s/ Deloitte & Touche LLP

Portland, Oregon

February 27, 2008

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PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

(Dollars in millions, except per share amounts)

Years Ended December 31	**2007**	**2006**	**2005**
Revenues	$ 1,743	$ 1,520	$ 1,446
Operating expenses:			
Purchased power and fuel	879	763	671
Production and distribution	150	140	128
Administrative and other	184	164	168
Depreciation and amortization	181	219	233
Taxes other than income taxes	80	75	74
Income taxes	71	38	46
Total operating expenses	1,545	1,399	1,320
Income from operations	198	121	126
Other income (deductions):			
Allowance for equity funds used during construction	16	16	8
Miscellaneous	8	1	(5)
Income taxes	(3)	2	3
Total other income	21	19	6
Interest expense	74	69	68
Net income	$ 145	$ 71	$ 64
Common Stock:			
Weighted-average shares outstanding (in thousands):			
Basic	62,512	62,501	62,500
Diluted	62,534	62,505	62,500
Earnings per share - basic and diluted	$ 2.33	$ 1.14	$ 1.02
Dividends declared per share	$ 0.93	$ 0.675	$ *

* Not meaningful as PGE was a wholly-owned subsidiary of Enron.

The accompanying notes are an integral part of these consolidated financial statements.

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PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(In millions, except share amounts)

At December 31	2007	2006
ASSETS		
Electric utility plant, net:		
Electric utility plant at cost (includes construction work in progress of $126 and $412)	$ 5,024	$ 4,582
Less: accumulated depreciation and amortization	(1,958)	(1,864)
Electric utility plant, net	3,066	2,718
Other property and investments:		
Nuclear decommissioning trust, at market value	46	42
Non-qualified benefit plan trust	69	70
Miscellaneous	19	26
Total other property and investments	134	138
Current assets:		
Cash and cash equivalents	73	12
Accounts and notes receivable (less allowance for uncollectible accounts of $5 and $45)	178	177
Unbilled revenues	92	88
Assets from price risk management activities	64	93
Inventories, at average cost	64	64
Other current assets	67	93
Total current assets	538	527
Regulatory assets	304	351
Other noncurrent assets	66	33
Total assets	$ 4,108	$ 3,767
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common stock, no par value, 80,000,000 shares authorized; 62,529,787 and 62,504,767 shares issued and outstanding at December 31, 2007 and 2006, respectively	$ 646	$ 643
Accumulated other comprehensive loss	(4)	(6)
Retained earnings	674	587
Total shareholders equity	1,316	1,224
Long-term debt	1,313	937
Total capitalization	2,629	2,161
Commitments and Contingencies (see Notes)		
Current liabilities:		
Accounts payable and other accruals	227	212
Liabilities from price risk management activities	101	155
Accrued taxes	23	14

Short-term borrowings		-		81
Long-term debt due within one year		-		66
Other current liabilities		40		34
Total current liabilities		391		562
Regulatory liabilities		574		523
Deferred income taxes		279		251
Non-qualified benefit plan liabilities		86		84
Trojan asset retirement obligation		62		108
Accumulated asset retirement obligation		29		26
Other noncurrent liabilities		58		52
Total liabilities		1,479		1,606
Total capitalization and liabilities	$	4,108	$	3,767

The accompanying notes are an integral part of these consolidated financial statements.

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PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS EQUITY

(Dollars in millions)

	Common Stock		Accumulated Other Comprehensive	Retained	Total Shareholders
	Shares	Amount	Loss	Earnings	Equity
Balances at December 31, 2004	62,500,000	$ 642	$ (6)	$ 644	$ 1,280
Dividends declared	-	-	-	(150)	(150)
Net income	-	-	-	64	64
Other comprehensive income	-	-	3	-	3
Balances at December 31, 2005	62,500,000	642	(3)	558	1,197
Vesting of restricted stock units	4,767	-	-	-	-
Stock-based compensation	-	1	-	-	1
Dividends declared	-	-	-	(42)	(42)
Net income	-	-	-	71	71
Other comprehensive income	-	-	1	-	1
Initial adjustment to adopt SFAS 158	-	-	(4)	-	(4)
Balances at December 31, 2006	62,504,767	643	(6)	587	1,224
Vesting of restricted stock units	16,841	-	-	-	-
Shares issued pursuant to employee stock purchase plan	8,179	-	-	-	-
Stock-based compensation	-	3	-	-	3
Dividends declared	-	-	-	(58)	(58)
Net income	-	-	-	145	145
Other comprehensive income	-	-	2	-	2
Balances at December 31, 2007	62,529,787	$ 646	$ (4)	$ 674	$ 1,316

The accompanying notes are an integral part of these consolidated financial statements.

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PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In millions)

Years Ended December 31	**2007**	**2006**	**2005**
Net income	$ 145	$ 71	$ 64
Other comprehensive income (loss) items, net of taxes:			
Unrealized gains (losses) on cash flow hedges:			
Unrealized holding net gains (losses), net of taxes of $2 in 2007, $16 in 2006, and $(18) in 2005	(2)	(26)	28
Reclassification to net income for contract settlements, net of taxes of $(1) in 2007, $7 in 2006, and $(3) in 2005	2	(11)	4
Reclassification to net income due to discontinuance of cash flow hedges, net of taxes of $1 in 2005	-	-	(1)
Reclassification of unrealized gains (losses) to SFAS 71 regulatory asset (liability), net of taxes of $(1) in 2007, $(24) in 2006, and $19 in 2005	-	37	(29)
Total unrealized gains on cash flow hedges	-	-	2
Pension and other postretirement plans funded position, net of taxes of $(12)	20	-	-
Reclassification of defined benefit pension plan and other benefits to SFAS 71 regulatory asset, net of taxes of $12	(18)	-	-
Minimum pension liability adjustment	-	1	1
Total other comprehensive income items, net of taxes	2	1	3
Comprehensive income	$ 147	$ 72	$ 67

The accompanying notes are an integral part of these consolidated financial statements.

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PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)

Years Ended December 31	**2007**	**2006**	**2005**
Cash flows from operating activities:			
Net income	$ 145	$ 71	$ 64
Reconciliation of net income to net cash provided by operating activities:			
Depreciation and amortization	181	219	233
Net assets from price risk management activities	(26)	132	(40)
Regulatory deferrals - price risk management activities	26	(132)	36
Deferred income taxes	22	(38)	(53)
Allowance for equity funds used during construction	(16)	(16)	(8)
Senate Bill 408 deferrals	(16)	42	-
Power cost deferrals	(9)	-	18
Other non-cash income and expenses, net	1	-	16
Changes in working capital:			
Net margin deposit activity	21	(94)	35
(Increase) decrease in receivables	(4)	17	(29)
Increase (decrease) in payables	19	(88)	82
Other working capital items, net	(2)	(11)	4
Other, net	2	4	14
Net cash provided by operating activities	344	106	372
Cash flows from investing activities:			
Capital expenditures	(455)	(371)	(255)
Purchases of nuclear decommissioning trust securities	(23)	(37)	(34)
Sales of nuclear decommissioning trust securities	21	21	21
Proceeds from sale of assets	-	6	-
Other, net	6	1	(4)
Net cash used in investing activities	(451)	(380)	(272)
Cash flows from financing activities:			
Issuance of long-term debt	381	275	-
Short-term borrowings, net	(81)	81	-
Repayment of long-term debt	(71)	(162)	(32)
Dividends paid	(58)	(28)	(150)
Debt issuance costs	(3)	(2)	-
Net cash provided by (used in) financing activities	168	164	(182)
Increase (decrease) in cash and cash equivalents	61	(110)	(82)
Cash and cash equivalents, beginning of year	12	122	204
Cash and cash equivalents, end of year	$ 73	$ 12	$ 122

Supplemental disclosures of cash flow information:

Cash paid during the year:						
Interest, net of amounts capitalized	$	58	$	55	$	58
Income taxes		46		101		88
Non-cash investing and financing activities:						
Accrued capital additions		27		20		9
Common stock dividends declared but not paid		15		14		-

The accompanying notes are an integral part of these consolidated financial statements.

Portland General Electric Company and Subsidiaries

Notes to Consolidated Financial Statements

Nature of Operations

Portland General Electric Company (PGE, or the Company) is a single, vertically integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the State of Oregon. The Company also sells electricity and natural gas in the wholesale market to utilities, brokers, and power marketers located throughout the western United States. PGE operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. PGE s corporate headquarters is located in Portland, Oregon and its service area is located entirely within Oregon. PGE s service area includes 52 incorporated cities, of which Portland and Salem are the largest, within a state-approved service area allocation of approximately 4,000 square miles. At the end of 2007, PGE s service area population was approximately 1.6 million, comprising about 43% of the state s population. The Company served approximately 804,000 retail customers at December 31, 2007.

Note 1 - Summary of Significant Accounting Policies

Consolidation Principles

The consolidated financial statements include the accounts of PGE and its wholly-owned subsidiaries. The Company s ownership share of direct expenses and costs related to jointly-owned generating plants are also included in the consolidated financial statements. Intercompany balances and transactions have been eliminated.

Basis of Accounting

PGE and its subsidiaries financial statements conform to accounting principles generally accepted in the United States. In addition, PGE s accounting policies are in accordance with the requirements and the rate making practices of regulatory authorities having jurisdiction.

Use of Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosures of contingent liabilities, at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Contingencies

Contingencies are evaluated based on Statement of Financial Accounting Standards No. (SFAS) 5, *Accounting for Contingencies*, using the best information available. A material loss contingency is accrued and disclosed when it is probable that an asset has been impaired or a liability incurred and the amount of the loss can be reasonably estimated. If a range of possible loss is established, the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate. If the probable loss cannot be reasonably estimated, no accrual is recorded, but the loss contingency is disclosed to the effect that the probable loss cannot be reasonably estimated. A material loss contingency will be disclosed when it is reasonably possible that an asset has been impaired or a liability incurred. Gain contingencies are recognized upon realization and are disclosed when material.

Reclassifications

Certain amounts in prior year financial statements have been reclassified for comparative purposes. Specifically, Allowance for equity funds used during construction and Senate Bill 408 deferrals,

previously classified within Other non-cash income and expenses, net on the Consolidated Statements of Cash Flows, are now reported separately. These reclassifications had no effect on PGE s previously reported consolidated financial position, results of operations, or cash flows.

Revenue Recognition

Retail revenues are recognized when monthly billings are made for energy sold to customers and delivered to those customers that purchase their energy from Energy Service Suppliers (ESSs). In addition, estimated unbilled revenues are accrued for services provided to retail customers from the meter read date to month-end. Unbilled revenues are calculated based upon each month s actual net system load, the number of days from meter-reading date to month-end, and current retail customer prices. Estimated provisions for uncollectible accounts receivable related to retail electricity sales, charged to Administrative and other expense, are recorded in the same period as the related revenues, with an offsetting credit to the allowance for uncollectible accounts. Such estimates are based on management s assessment of the probable collection of customer accounts, aging of accounts receivable, bad debt write-offs, actual customer billings, and other factors.

Wholesale revenues are recognized as energy is delivered to the Company s wholesale customers (primarily utilities and energy marketers) during the month. Provisions related to wholesale accounts receivable and unsettled positions, charged to Purchased power and fuel expense, are based on a periodic review and evaluation that includes counterparty non-performance risk and contractual rights of offset when applicable. Actual amounts written off are charged to the allowance for uncollectible accounts.

In certain situations, PGE defers the recognition of revenues until the period in which the related costs are incurred, in accordance with the provisions of SFAS 71, *Accounting for the Effects of Certain Types of Regulation*.

Purchased Power

In addition to power purchases and certain price risk management activities (described under Price Risk Management in this Note), certain other activities are reflected in Purchased power and fuel expense. These consist of: 1) amounts related to certain power cost adjustments and deferrals; 2) amounts recorded under PGE s long-term power exchange contracts that help meet seasonal peaking requirements (for further information, see Purchased Power in Note 9, Commitments and Guarantees); and, 3) provisions related to wholesale accounts receivable and unsettled positions (described under Revenue Recognition in this Note).

Price Risk Management

PGE engages in price risk management activities in its electric business, utilizing derivative instruments such as forward, swap, and option contracts for electricity and natural gas, and futures contracts for natural gas. Under SFAS 133, *Accounting for Derivative Instruments and Hedging Activities (as amended)*, derivative instruments are recorded on the Consolidated Balance Sheets as Assets and Liabilities from price risk management activities measured at fair value, unless they qualify for the normal purchases and normal sales exception, with changes in fair value recognized currently in earnings unless hedge accounting applies.

Certain electricity forward contracts that were entered into in anticipation of serving the Company s regulated retail load meet the requirements for treatment under the normal purchases and normal sales exception under SFAS 133, as amended by SFAS 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*. Other activities consist of certain electricity forwards and natural gas forwards and swaps that qualify as cash flow hedges of forecasted transactions, and electricity options, certain electricity forwards, certain natural gas swaps and forward contracts for acquiring Canadian dollars. Such activities are utilized to protect against variability in expected future cash flows due to associated price risk and to minimize net power costs for retail customers.

The Public Utility Commission of Oregon (OPUC), which regulates PGE s retail electricity business, recognizes derivative contracts only at the time of settlement. Contracts that qualify for the normal purchases and normal sales exception are not required to be recorded at fair value. Unrealized gains and losses from contracts that qualify as cash flow hedges are recorded net in Other comprehensive income (OCI) and contracts designated as non-hedges are recorded net in Purchased power and fuel expense on the Statements of Income. The timing difference between the recognition of unrealized gains and losses on derivative instruments and their realization and subsequent recovery in rates is recorded as a regulatory asset or regulatory liability to reflect the effects of regulation under SFAS 71.

Prior to December 2006, PGE recorded a regulatory asset or regulatory liability under SFAS 71 to offset unrealized gains and losses on certain contracts recorded prior to settlement to the extent that such contracts were included in the Company s Resource Valuation Mechanism (RVM). The regulatory asset or regulatory liability is reflected within Regulatory assets or Regulatory liabilities, respectively, on the Consolidated Balance Sheets. Upon settlement, the regulatory asset or regulatory liability is reversed. In its January 17, 2007 general rate order, the OPUC approved a new Power Cost Adjustment Mechanism (PCAM) by which PGE can adjust future rates to reflect a portion of the difference between each year s forecasted and actual net variable power costs (NVPC). As a result, a regulatory asset or regulatory liability is recorded to offset changes in fair value of derivative instruments not included in the RVM. Effective with the January 17, 2007 order, a new Annual Power Cost Update Tariff replaced the RVM.

Sales and purchases involving electricity derivative activities that are physically settled are recorded in Revenues and Purchased power and fuel expense, respectively. Electricity derivative activities that are booked out (not physically settled) are recorded on a net basis in Purchased power and fuel expense, pursuant to the requirements of Emerging Issues Task Force Issue No. (EITF) 03-11, *Reporting Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes as Defined in Issue 02-3.* For further information, see Note 10.

Stock-Based Compensation

Stock-based compensation is accounted for in accordance with SFAS 123 (revised 2004), *Share-based Payments* (SFAS 123R), which requires the measurement and recognition of compensation expense for all share-based payment awards, including restricted stock units, based on the estimated fair value of the awards. Under SFAS 123R, the fair value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite service period. PGE attributes the value of stock-based compensation to expense on a straight-line basis. For further information, see Note 5.

Counterparty and Customer Deposits

In the course of its wholesale activities, PGE both receives and deposits performance assurance cash collateral, with required amounts based upon provisions contained in certain wholesale power agreements with counterparties. Amounts deposited with counterparties under such agreements are reflected as margin deposits and classified in Other current assets in the Consolidated Balance Sheets and were $28 million and $46 million at December 31, 2007 and 2006, respectively. Amounts received from counterparties under such agreements are reflected as customer deposits and are classified in Other current liabilities in the Consolidated Balance Sheets and were $8 million and $5 million at December 31, 2007 and 2006, respectively, which includes certain retail and transmission customer deposits received.

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Capitalization of Property, Plant and Equipment

Additions to utility plant are capitalized at their original cost, consistent with accounting and regulatory guidelines. Costs include direct labor, materials and supplies, and contractor costs, as well as indirect costs such as engineering, supervision, employee benefits, and allowance for funds used during construction. Plant replacements are capitalized, with minor items charged to expense as incurred. The costs to purchase/develop software applications are capitalized in accordance with American Institute of Certified Public Accountants Statement of Position 98-1, *Accounting for the Costs of Computer Software Developed or Obtained for Internal Use*. Costs of relicensing the Company s hydroelectric projects are capitalized and amortized over the related license period.

Utility plant consists of the following (in millions):

	December 31, 2007	December 31, 2006
Production	$ 1,944	$ 1,414
Transmission	329	283
Distribution	2,184	2,059
General	252	242
Intangible	189	172
Construction work in progress	126	412
Total electric utility plant	$ 5,024	$ 4,582

Depreciation and Amortization of Property, Plant and Equipment

Depreciation is computed using the straight-line method, based upon original cost and includes an estimate for cost of removal and expected salvage. Depreciation expense as a percent of the related average depreciable plant in service was approximately 3.9% in 2007, 4.3% in 2006, and 4.4% in 2005. Estimated asset retirement removal costs included in depreciation expense were $43 million, $68 million, and $64 million in 2007, 2006, and 2005, respectively. The reductions in 2007 are related to PGE s most recent depreciation study, as described below.

Periodic studies are conducted to update depreciation parameters (i.e. retirement dispersion patterns, average service lives, and net salvage rates), including estimates of Asset Retirement Obligations (AROs) and asset retirement removal costs. The studies are conducted every five years and are filed with the OPUC for approval and inclusion in a future rate proceeding. The results of the most recent depreciation study, filed in November 2005, were incorporated into customer rates that became effective on January 17, 2007.

Thermal production plants are depreciated using a life-span methodology which ensures that plant investment is recovered by the forecasted retirement date. These dates range from 2020 to 2042. Depreciation is provided on the Company s other classes of plant in service over their estimated average service lives, which are as follows: Hydro, 88 years; Wind, 27 years; Transmission, 48 years; Distribution, 38 years; and General, 14 years.

The original cost of depreciable property units, net of any related salvage value, is charged to accumulated depreciation when property is retired and removed from service. Cost of removal expenditures are charged to asset retirement obligations for assets with AROs and to accumulated asset retirement removal costs, included in Regulatory liabilities, for assets without AROs. For further information, see Note 12.

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Intangible plant consists primarily of computer software development costs, which are amortized over either five or ten years, and hydro relicensing costs, which are amortized over the applicable license term. Amortization expense for 2007, 2006, and 2005, was $15 million, $15 million, and $13 million, respectively. Accumulated amortization was $96 million and $82 million at December 31, 2007 and December 31, 2006, respectively.

Major Maintenance Expenses

Costs of periodic major maintenance inspections and overhauls at the Company s generating plants are charged to operating expense as incurred. Due to the variability of major maintenance expenses at the Coyote Springs combustion turbine generating plant, PGE s retail customer prices include the recovery of an annual amount, as authorized by the OPUC. Differences between amounts authorized in prices and actual Coyote Springs maintenance expenses are deferred as regulatory assets or regulatory liabilities pursuant to SFAS 71.

Allocations and Loadings

PGE utilizes a series of cost distributions and loadings to allocate certain administrative and overhead costs between capital and operating accounts, based primarily on construction activities of the Company.

Allowance for Funds Used During Construction (AFDC)

AFDC represents the pre-tax cost of borrowed funds used for construction purposes and a reasonable rate for equity funds. It is capitalized as part of the cost of plant and is credited to income but does not represent current cash earnings. The average rate used by PGE in 2007 was 8%, while the rates for 2006 and 2005 were 9%. AFDC from borrowed funds was $10 million in 2007, $8 million in 2006, and $4 million in 2005 and is reflected in the Consolidated Statements of Income as a reduction to interest expense. AFDC from equity funds was $16 million in 2007, $16 million in 2006, and $8 million in 2005 and is reflected as a component of Other income (deductions).

Debt Issuance Costs

Underwriting, legal, and other direct costs related to the issuance of debt securities are deferred and amortized to interest expense equitably over the life of the security. Unamortized debt issuance costs at December 31, 2007 and 2006 were $16 million and $15 million, respectively, and are included within Other noncurrent assets on the Consolidated Balance Sheets.

Income Taxes

PGE files consolidated federal and state income tax returns. The Company s policy is to collect for tax liabilities from subsidiaries that generate taxable income and to reimburse subsidiaries for tax benefits utilized in its tax return. Deferred income taxes are recorded for temporary differences between financial and income tax reporting. Investment tax credits utilized have been deferred and are being amortized to income over a period which will end in 2011, which corresponds with the lives of the related properties. Interest and penalties related to any future income tax deficiencies will be recorded within Interest expense and Other income (deductions), respectively, in the Consolidated Statements of Income.

Cash and Cash Equivalents

Highly liquid investments with maturities of three months or less at the date of acquisition are classified as cash equivalents. Cash equivalents consist of money market funds and total $59 million and zero at December 31, 2007 and 2006.

Non-Qualified Benefit Plan Trust

The non-qualified benefit plan trust is comprised of insurance contracts and investments in money market, bond, and other equity investments. The cash surrender value of insurance contracts is reported as an asset at the end of the reporting period, with changes in such values between reporting periods recognized as income or expense of the period. For further information, see Note 2. The cash surrender values of insurance contracts, the majority of which are held in the trust, were $22 million and $23 million at December 31, 2007 and 2006, respectively. The investments in marketable securities are classified as trading and recorded at fair value on the Consolidated Balance Sheets. Realized and unrealized gains and losses on these investments are determined using average cost and are included in Other income (deductions) on the Consolidated Statements of Income. Investments in marketable securities and cash totaled $47 million at December 31, 2007 and 2006.

Accumulated Other Comprehensive Income

SFAS 130, *Reporting Comprehensive Income,* establishes standards for the reporting of comprehensive income and its components. Accumulated other comprehensive income (AOCI) is comprised of the difference between the pension and other postretirement plans obligations recognized in earnings to date, and the funded position at December 31, 2007 and 2006. With the adoption of SFAS 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans* (SFAS 158) on December 31, 2006, PGE recorded an initial adjustment to reflect the provisions of SFAS 158.

Inventories

PGE s inventories are recorded at cost, which includes the purchase price (less discounts), applicable taxes, transportation and handling, etc. The average cost method is utilized to price inventory as fuel is burned at the generating plants and as materials and supplies are issued for operations, maintenance and capital activities. General storeroom operation costs, including procurement, management, and storage, are recorded in the unallocated stores account and distributed equitably as materials and supplies are issued.

Inventories consist of the following (in millions):

	December 31,	
	2007	**2006**
Coal	$ 16	$ 20
Fuel oil	10	10
Natural gas	3	3
Materials and supplies	32	28
Unallocated stores account	3	3
Total	$ 64	$ 64

Asset Retirement Obligations

Asset retirement obligations are accounted for in accordance with SFAS 143, *Accounting for Asset Retirement Obligations,* which requires that the fair value of a liability for an ARO be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. Because of the long lead time involved until future decommissioning activities occur, the Company uses present value techniques as quoted market prices and a market-risk premium are not available. The present value of estimated future removal expenditures, which is revised periodically, is recorded as an ARO on the Consolidated Balance Sheets, with actual expenditures charged to the ARO as incurred. For further information, see Notes 12 and 13.

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Regulatory Assets and Liabilities

As a rate-regulated enterprise, the Company applies SFAS 71, *Accounting for the Effects of Certain Types of Regulation* (SFAS 71). Regulatory assets represent probable future revenue associated with certain costs that will be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are to be credited to customers through the ratemaking process. Accounting under SFAS 71 is appropriate as long as rates are established by or subject to approval by independent third-party regulators; rates are designed to recover the specific enterprise s cost of service; and in view of demand for service, it is reasonable to assume that rates set at levels that will recover costs can be charged to and collected from customers.

As of December 31, 2007, the majority of PGE s regulatory assets and liabilities are reflected in customer rates and are amortized over the period in which they are included in billings to customers. Items not currently reflected in rates are pending before the regulatory body as discussed below. Based on such rates, PGE estimates that it will collect substantially all of is regulatory assets, and refund its regulatory liabilities (excluding those related to asset retirement obligations and removal costs), within the next 12 years.

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

	December 31,	
	2007	**2006**
Regulatory assets:		
Income taxes recoverable (1)	$ 87	$ 74
Pension and other postretirement plans (1)	57	87
Price risk management (1)	37	62
Boardman power cost deferral (2)	31	6
Debt reacquisition costs (1)	28	30
Trojan decommissioning costs	16	66
Oregon Senate Bill 408 (SB 408) - 2007 (2)	16	-
Residential Exchange Program (2)	9	-
Regulatory restructuring costs (2)	5	11
Beaver 8 (2)	5	7
Miscellaneous (3)	13	8
Total regulatory assets	$ 304	$ 351
Regulatory liabilities:		
Accumulated asset retirement removal costs	$ 451	$ 411
Oregon Senate Bill 408 (SB 408) - 2006 (2)	42	42
Asset retirement obligations	28	27
Trojan ISFSI pollution control tax credits (2)	13	10
Power Cost Adjustment Mechanism (PCAM) (2)	16	-
Residential Exchange Program (2)	-	14
Miscellaneous (4)	24	19
Total regulatory liabilities	$ 574	$ 523

(1) At December 31, 2007, PGE had regulatory assets not earning a return on investment of $212 million.
(2) A return on the unamortized balance of these items is recorded at PGE s authorized cost of capital (9.083% through 2006 and 8.29% beginning on January 17, 2007).
(3) Of the total miscellaneous unamortized balances, a return is recorded on $3 million at both December 31, 2007 and 2006 at PGE s authorized cost of capital, as indicated in (2) above.
(4) Of the total miscellaneous unamortized balances, a return is recorded on $12 million and $15 million at December 31, 2007 and 2006, respectively, at PGE s authorized cost of capital, as indicated in (2) above.

Circumstances that could result in the discontinuance of SFAS 71 include (1) increased competition that restricts the Company s ability to establish prices to recover specific costs, and (2) a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. PGE periodically reviews the criteria of SFAS 71 to ensure that its continued application is appropriate. Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, management believes that the Company s regulatory assets are probable of future recovery.

Income taxes recoverable - The amount represents tax benefits previously flowed to customers through rates for temporary differences between book and tax reporting. The balance is reduced as temporary differences reverse and the increase in current tax expense is recovered in customer rates. PGE expects recovery over the next 17 years.

Pension and other postretirement plans - On December 31, 2006, PGE adopted SFAS 158, which requires that the funded status of pension and other postretirement plans be recognized, with the resulting adjustment recorded to the ending balance of AOCI on the Consolidated Balance Sheets. Postretirement costs are covered in rates charged to customers. The OPUC issued an accounting order that authorizes PGE to record a regulatory asset equal to the pre-tax charge against AOCI that would otherwise be required by recognition of the pension funded status under SFAS 158. As pension expense is recognized in future years, the regulatory asset will be reduced. PGE expects recovery over the average service life of its employees. For further information, see Note 2.

Price risk management - SFAS 133 requires that unrealized gains and losses on derivative instruments that do not qualify for the normal purchase and normal sale exception be recorded in earnings or OCI in the current period. To reflect the effects of regulation under SFAS 71, timing differences between the recognition of unrealized gains and losses on derivative instruments and their realization and subsequent recovery in rates are recorded as regulatory assets or regulatory liabilities. Amounts recorded by PGE at December 31, 2007 and 2006 offset the effects of such gains and losses, which are caused by changes in fair values of related energy contracts. Recorded amounts are reversed as such contracts are settled. PGE expects recovery over the next 4 years. For further information, see Note 10.

Boardman power cost deferral - In October 2005, the Boardman Coal Plant (Boardman) was taken out of service for repair of the plant s steam turbine rotor and remained out of service during the first half of 2006 for additional repairs. PGE incurred significant incremental power costs during this period to replace the plant s generation. In November 2005, PGE filed with the OPUC an application to defer for later ratemaking treatment excess power costs associated with Boardman s turbine rotor repair outage. Based upon prior OPUC actions, the stated position of the OPUC staff in the proceeding, and considering both applicable accounting guidance and the impact of SB 408 on any benefit received by the Company, PGE recorded a deferral in the amount of $6 million at December 31, 2006. On February 12, 2007, the OPUC issued an order granting a portion of PGE s request and authorizing the Company to defer $26.4 million, subject to a prudency review process. PGE recorded the deferral of $20.4 million in the first quarter 2007. On October 9, 2007, PGE filed a request with the OPUC to amortize the deferral of $26.4 million of replacement power costs, plus interest until the amortization period begins (accrued interest is $5.0 million as of December 31, 2007), associated with the outage of Boardman from November 18, 2005 through February 5, 2006. In its filing, the Company proposed that the amortization be offset with certain credits due to customers, with no price impact anticipated. PGE s request is subject to both a prudency review with respect to the outage and to a regulated earnings test.

Debt reacquisition costs - As authorized by the OPUC, costs related to the reacquisition of debt securities, including unamortized debt issuance costs related to such debt securities, are deferred and amortized to interest expense equitably over the life of the replacement or retired issue as applicable. PGE expects recovery over the next 25 years.

Trojan decommissioning costs - PGE s retail prices include recovery of costs to decommission Trojan. These amounts represent the estimated present value of future decommissioning expenditures to be recovered from customers. For further information, see Note 13.

SB 408 - This Oregon law attempts to more closely match income tax amounts forecasted to be collected in revenues with the amount of income taxes paid to governmental entities by investor-owned utilities or their consolidated group. The Company has established a regulatory liability for future refunds to customers related to the 2006 reporting year. PGE filed its report on October 15, 2007 with the OPUC reflecting the amount of taxes paid by the Company, as well as the amount of taxes authorized to be collected in rates. The report is being reviewed as part of a formal process, with the OPUC expected to issue an order in April 2008. The Company has reached agreement with OPUC Staff and certain interveners that the appropriate refund due customers is $37.2 million plus accrued interest, based on the OPUC s administrative rules that govern the calculation of the refund amount. This regulatory liability includes $17 million paid to Enron Corp. for net current taxes payable for the first quarter of 2006 when PGE was included in its former parent s consolidated group for filing consolidated federal and state income tax returns. Under OPUC rules, refunds to customers for the 2006 reporting year will begin on June 1, 2008. For 2007, a regulatory asset was established for collection from customers. For further information, see Note 15.

Residential Exchange Program - The Residential Exchange Program, which is administered by the Bonneville Power Administration (BPA), provides access to the benefits of federal power to residential and small farm customers of the region s investor-owned utilities. In 2000, PGE entered into a settlement agreement with the BPA related to the Residential Exchange Program covering the period October 1, 2001 through September 30, 2011. The benefits that PGE receives under the agreement with the BPA are passed through directly to residential and small farm customers in the form of monthly billing credits. Based upon decisions in the U.S. Ninth Circuit Court of Appeals, the BPA, on May 21, 2007, notified PGE and six other investor-owned utilities that it was immediately suspending the Residential Exchange Program payments. In its notice, the BPA indicated that the suspension will continue at least until any petitions for rehearing on the decisions are finally resolved. The $9 million regulatory asset represents Residential Exchange Program credits that were passed through to eligible customers but not received from the BPA.

Regulatory restructuring costs - The OPUC authorized PGE to defer certain costs related to implementation of Oregon s electricity restructuring law. Of the $24 million total implementation costs, $7 million was fully recovered over a five-year period that ended December 31, 2007, and $17 million is being recovered over a five-year period that began on January 1, 2004, with a remaining balance of $5 million at December 31, 2007.

Beaver 8 - In December 2004, the OPUC issued an order that adopted a stipulation in which parties agreed that PGE may recover from customers approximately $14 million associated with a 24.7 MW combustion turbine (referred to as Beaver 8) installed at the Company s Beaver generating plant site in 2001. Of this amount, $10 million (plus accrued interest) was deferred for recovery from customers over a five-year period beginning January 1, 2005, with the remaining $4 million to be recovered through depreciation charges included in general prices.

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Accumulated asset retirement removal costs - Asset retirement removal costs that do not qualify as AROs are a component of depreciation expense allowed in customer rates. Accumulated asset retirement removal costs are recorded as a regulatory liability as they are collected in rates, and are reduced by actual removal costs as incurred, in accordance with SFAS 143 and SFAS 71. This amount is also included as a reduction to PGE s rate base for ratemaking purposes.

Asset retirement obligations - SFAS 143 requires the recognition of AROs, measured at estimated fair value, for legal obligations related to dismantlement and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. Pursuant to regulation, AROs of rate-regulated long-lived assets are included as an allowable cost in rates charged to customers. Any differences in the timing of recognition of costs for financial reporting and ratemaking purposes are deferred as a regulatory asset or regulatory liability under SFAS 71. Asset retirement obligations are included in PGE s rate base for ratemaking purposes. For further information, see Note 13.

Trojan ISFSI pollution control tax credits - In December 2004, PGE received final certification from the Oregon Environmental Quality Commission (OEQC) related to $21.1 million in Oregon pollution control tax credits that were generated from PGE s investment in an Independent Spent Fuel Storage Installation (ISFSI) at Trojan. OEQC rules require that the tax credits be spread over a ten-year period, beginning in 2004. The OPUC approved the deferral of the tax credits for future ratemaking treatment.

Power Cost Adjustment Mechanism (PCAM) - A new PCAM was approved by the OPUC, effective January 17, 2007. Under the PCAM, PGE can adjust future prices to reflect a portion of the difference between each year s forecasted NVPC included in prices (the baseline), and actual NVPC. Under the PCAM, PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and that included in base prices by application of an asymmetrical deadband within which PGE absorbs cost increases or decreases, with a 90/10 sharing of costs and benefits between customers and the Company outside of the deadband. For 2007, the deadband ranged from $11.7 million below, to $23.4 million above, the baseline. PGE s actual NVPC as determined under the PCAM for 2007 were less than the established baseline by $29.4 million, thus an estimated refund to customers of $16.5 million, including accrued interest, was recorded as a regulatory liability and is reflected as an increase to Purchased power and fuel expense. A final determination of any customer refund or collection will be determined by the OPUC through a public filing and review.

New Accounting Standards

SFAS 157, *Fair Value Measurements* (SFAS 157), was issued in September 2006 and is effective for fiscal years beginning after November 15, 2007. (In February 2008, the FASB deferred the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis). SFAS 157 provides enhanced guidance for the use of fair value to measure assets and liabilities. It also requires expanded disclosure regarding the extent to which fair value is used for such measurements, information used to measure fair value, and the effect of fair value measurements on earnings. Provisions of SFAS 157 apply whenever other accounting standards require (or permit) assets or liabilities to be measured at fair value, but does not expand the use of fair value in any new circumstances. PGE believes that the adoption of SFAS 157 will not have a material impact on its consolidated financial position or consolidated results of operations.

SFAS 159, *The Fair Value Option for Financial Assets and Financial Liabilities* (SFAS 159), was issued in February 2007 and is effective for fiscal years beginning after November 15, 2007. SFAS 159 provides entities the option to report most financial assets and liabilities at fair value, with changes in fair value recorded in earnings. It also establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. PGE believes that the adoption of SFAS 159 will not have a material impact on its consolidated financial position or consolidated results of operations.

FASB Staff Position No. FIN 39-1, *Amendment of FASB Interpretation No. 39* (FSP FIN 39-1) was issued April 30, 2007 and modifies FIN 39, *Offsetting of Amounts Related to Certain Contracts*, and permits reporting entities to offset the receivable or payable recognized for derivative instruments that have been offset under a master netting arrangement. FSP FIN 39-1 requires financial statement disclosure of a reporting entity s accounting policy (to offset or not to offset) as well as amounts recognized for the right to reclaim cash collateral, or the obligation to return cash collateral, that have been offset against net derivative positions. FSP FIN 39-1 is effective for fiscal years beginning after November 15, 2007, with early application permitted. The effects of applying FSP FIN 39-1 shall be presented as a change in accounting principle through retrospective application for all financial statements presented unless it is impracticable to do so. PGE is in the process of determining the impact the application of FSP FIN 39-1 will have on its consolidated financial position, but believes the adoption of FSP FIN 39-1 will not have a material impact on its consolidated results of operations.

EITF 06-11, *Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards* (EITF 06-11) was ratified by the Emerging Issues Task Force at its June 27, 2007 meeting. EITF 06-11 clarifies how an entity should (1) recognize the income tax benefit received on dividends that are paid to employees holding equity-classified nonvested shares and (2) charged to retained earnings under SFAS 123R. EITF 06-11 applies prospectively to the income tax benefits that result from dividends on equity-classified employee share-based payment awards that are declared in fiscal years beginning after December 15, 2007, and interim periods within those fiscal years. PGE believes the adoption of EITF 06-11 will not have a material impact on its consolidated financial position or consolidated results of operations.

Note 2 - Employee Benefits

Pension and Other Postretirement Plans

Defined Benefit Pension Plan - PGE sponsors a non-contributory defined benefit pension plan, of which substantially all members are current or former PGE employees. The assets of the pension plan are held in a trust. Pension plan calculations include several assumptions which are reviewed annually and are updated as appropriate.

PGE made no contributions to the pension plan in 2006 and 2007 and does not currently expect to make any contribution in 2008. The measurement date for the pension plan is December 31.

Non-Qualified Benefit Plans - The Non-Qualified Benefit Plans in the accompanying table consist primarily of obligations for a Supplemental Executive Retirement Plan (SERP). The SERP was closed to new participants in 1997. Investments in a non-qualified benefit plan trust, consisting of trust owned life insurance policies (TOLI) and marketable securities, are intended to be the primary source for funding these plans. Trust assets of $25 million as of December 31, 2007 and 2006 are included in the accompanying table for informational purposes only and are not considered segregated and restricted as defined by SFAS 158. The investments in marketable securities, consisting of money market, bond, and equity mutual funds, are classified as trading and recorded at fair value. The measurement date for the non-qualified plans is December 31.

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Other Benefits - PGE also participates in non-contributory postretirement health and life insurance plans (Other Benefits in the table). Employees are covered under a Defined Dollar Medical Benefit Plan which limits PGE s obligation by establishing a maximum benefit per employee. Contributions made to a voluntary employees beneficiary association trust are used to fund these plans. Costs of these plans, based upon an actuarial study, are included in rates charged to customers. Post-retirement benefit plan calculations include several assumptions which are reviewed annually with PGE s consulting actuaries and trust investment consultants and updated as appropriate.

PGE has also established Health Retirement Accounts (HRAs) for its employees. Contributions are made to trust accounts to provide for claims by retirees for qualified medical costs. The 2004 bargaining unit agreement provides that participants accounts are credited with 58% of the value of the employee s accumulated sick time as of April 30, 2004 and 100% of their earned time off accumulated at the time of retirement. Between July 1, 2007 and June 30, 2008, the Company will make additional contributions to the trust of $0.25 per compensable hour for each participant, increasing to $0.50 per compensable hour through February 28, 2009. The Company also grants a fixed dollar amount for all active non-bargaining employees, which will become available for qualified medical expenses upon their retirement.

No contributions were made to the postretirement or non-bargaining HRA plans in 2007. Contributions totaling $1 million were made to the bargaining unit HRA in 2007, with similar contributions expected in 2008. No contributions are currently expected to be made to the other postretirement plans in 2008. The measurement date for the postretirement plans is December 31.

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The following table provides a reconciliation of changes in the Plans benefit obligations and fair value of assets, a statement of the funded status, and components of net periodic benefit cost (dollars in millions):

	Defined Benefit Pension Plan 2007	Defined Benefit Pension Plan 2006	Non-Qualified Benefit Plans 2007	Non-Qualified Benefit Plans 2006	Other Benefits 2007	Other Benefits 2006
Reconciliation of benefit obligation:						
Benefit obligation at January 1	$ 492	$ 483	$ 26	$ 24	$ 58	$ 59
Service cost	13	13	-	-	2	1
Interest cost	27	27	1	2	4	3
Plan amendments	-	-	-	-	5	-
Participants contributions	-	-	-	-	1	1
Actuarial (gain) loss	(31)	(6)	(2)	2	3	(2)
Prior service cost	-	-	1	-	-	-
Benefit payments	(26)	(25)	(2)	(2)	(5)	(4)
Benefit obligation at December 31	$ 475	$ 492	$ 24	$ 26	$ 68	$ 58
Reconciliation of fair value of plan assets:						
Fair value of plan assets at January 1	$ 503	$ 469	$ 25	$ 24	$ 28	$ 27
Actual return on plan assets	41	59	2	3	2	3
Company contributions	-	-	-	-	1	1
Participants contributions	-	-	-	-	1	1
Benefit payments	(26)	(25)	(2)	(2)	(5)	(4)
Fair value of plan assets at December 31	$ 518	$ 503	$ 25	$ 25	$ 27	$ 28
Funded (unfunded) status at December 31	$ 43	$ 11	$ 1	$ (1)	$ (41)	$ (30)
Accumulated benefit obligation at December 31	$ 420	$ 436	$ 20	$ 20	N/A	N/A
Amounts in the Consolidated Balance Sheets consist of:						
Noncurrent asset	$ 43	$ 11	$ -	$ -	$ -	$ -
Current liability	-	-	(1)	(2)	-	-
Noncurrent liability	-	-	(23)	(24)	(41)	(30)
Net asset (liability)	$ 43	$ 11	$ (24)	$ (26)	$ (41)	$ (30)
Amounts recognized in comprehensive income consist of:						
Net actuarial loss/(gain)	$ (30)	$ *	$ (2)	$ -	$ 3	$ *
Prior service cost	-	*	1	-	5	*
Amortization of net actuarial loss	(3)	*	(1)	-	-	*
Amortization of prior service cost	(1)	*	-	-	(3)	*
Amortization of transition obligation	-	*	-	-	(1)	*
Minimum pension liability adjustment	N/A	*	N/A	(1)	N/A	*
Net amount recognized	$ (34)**	$ *	$ (2)	$ (1)	$ 4**	$ *
Amounts in AOCI consist of:						
Net actuarial loss	$ 36	$ 69	$ 7	$ 9	$ 10	$ 7
Prior service cost	3	4	-	-	8	6
Transition obligation	-	-	-	-	-	1
Net amount	$ 39 **	$ 73 **	$ 7	$ 9	$ 18**	$ 14**

Assumptions:

Discount rate used to calculate benefit obligation	6.50 %	5.75 %	6.50 %	5.75 %	5.75 % - 6.25 %	5.75 %
Weighted-average rate of increase in future compensation levels	4.42%	4.44%	N/A	N/A	5.07 %	5.07%
Long-term rate of return on assets	9.00%	9.00%	N/A	N/A	8.14 %	8.17%

* No activity in 2006, as SFAS 158 required an implementation adjustment to ending AOCI.

** Subsequently transferred to Regulatory assets.

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	Defined Benefit Pension Plan			Non-Qualified Benefit Plans			Other Benefits		
	2007	2006	2005	2007	2006	2005	2007	2006	2005
Components of net periodic benefit cost:									
Service cost	$ 13	$ 13	$ 12	$ -	$ -	$ -	$ 2	$ 1	$ 1
Interest cost on benefit obligation	27	27	25	1	1	1	4	3	3
Expected return on plan assets	(42)	(41)	(41)	-	-	-	(2)	(2)	(2)
Amortization of transition obligation	-	-	-	-	-	-	1	1	1
Amortization of prior service cost	1	1	2	-	-	1	3	1	1
Amortization of net actuarial loss	3	4	2	1	1	-	-	1	1
Actual return on plan assets	-	-	-	(2)	(2)	(1)	-	-	43

Total investments in unconsolidated affiliated companies	$ 246	$ 246

In February 2015, we sold our 35 percent equity interest in the third party logistics business, formerly Caterpillar Logistics Services LLC, to an affiliate of The Goldman Sachs Group, Inc. and investment funds affiliated with Rhône Capital LLC for $177 million, which was comprised of $167 million in cash and a $10 million note receivable included in Long-term receivables - trade and other in the Consolidated Statement of Financial Position. As a result of the sale, we recognized a pretax gain of $120 million (included in Other income (expense)) and derecognized the carrying value of our noncontrolling interest of $57 million, which was previously included in Other assets in the Consolidated Statement of Financial Position. The gain on the disposal is included as a reconciling item between Segment profit and Consolidated profit before taxes. The sale of this investment supports Caterpillar's increased focus on growth opportunities in its core businesses.

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7. Intangible assets and goodwill

A. Intangible assets

Intangible assets are comprised of the following:

(Millions of dollars)	Weighted Amortizable Life (Years)	Gross Carrying Amount	Accumulated Amortization	Net
	March 31, 2016			
Customer relationships	15	$2,525	$ (859)	$1,666
Intellectual property	11	1,629	(663)	966
Other	14	176	(67)	109
Total finite-lived intangible assets	14	$4,330	$ (1,589)	$2,741
	December 31, 2015			
Customer relationships	15	$2,489	$ (809)	$1,680
Intellectual property	11	1,660	(626)	1,034
Other	12	174	(67)	107
Total finite-lived intangible assets	14	$4,323	$ (1,502)	$2,821

Amortization expense for the three months ended March 31, 2016 and 2015 was $82 million and $87 million, respectively. Amortization expense related to intangible assets is expected to be:

(Millions of dollars)

Remaining Nine Months of 2016	2017	2018	2019	2020	Thereafter
$247	$330	$321	$320	$312	$1,211

B. Goodwill

No goodwill was impaired during the three months ended March 31, 2016 or 2015.

As discussed in Note 15, effective January 1, 2016, we revised our reportable segments in line with the changes to our organization structure. As a result of these changes, $118 million of goodwill was reassigned to Energy & Transportation from All Other segments.

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The changes in carrying amount of goodwill by reportable segment for the three months ended March 31, 2016 were as follows:

(Millions of dollars)	December 31, 2015	Acquisitions	Other Adjustments [1]	March 31, 2016
Construction Industries				
Goodwill	$ 285	$ —	$ 15	$ 300
Impairments	(22)	—	—	(22)
Net goodwill	263	—	15	278
Resource Industries				
Goodwill	4,145	—	57	4,202
Impairments	(580)	—	—	(580)
Net goodwill	3,565	—	57	3,622
Energy & Transportation				
Goodwill	2,738	—	18	2,756
All Other [2]				
Goodwill	49	—	5	54
Consolidated total				
Goodwill	7,217	—	95	7,312
Impairments	(602)	—	—	(602)
Net goodwill	$ 6,615	$ —	$ 95	$ 6,710

[1] Other adjustments are comprised primarily of foreign currency translation.
[2] Includes All Other operating segments (See Note 15).

8. Investments in debt and equity securities

We have investments in certain debt and equity securities, primarily at Insurance Services, that have been classified as available-for-sale and recorded at fair value. In addition, Insurance Services has an equity security investment in a real estate investment trust (REIT) which is recorded at fair value based on the net asset value (NAV) of the investment. These investments are primarily included in Other assets in the Consolidated Statement of Financial Position. Unrealized gains and losses arising from the revaluation of debt and equity securities are included, net of applicable deferred income taxes, in equity (Accumulated other comprehensive income (loss) in the Consolidated Statement of Financial Position). Realized gains and losses on sales of investments are generally determined using the specific identification method for debt and equity securities and are included in Other income (expense) in the Consolidated Statement of Results of Operations.

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The cost basis and fair value of debt and equity securities were as follows:

(Millions of dollars)	March 31, 2016 Cost Basis	March 31, 2016 Unrealized Pretax Net Gains (Losses)	March 31, 2016 Fair Value	December 31, 2015 Cost Basis	December 31, 2015 Unrealized Pretax Net Gains (Losses)	December 31, 2015 Fair Value
Government debt						
U.S. treasury bonds	$12	$ —	$12	$9	$ —	$9
Other U.S. and non-U.S. government bonds	72	—	72	71	1	72
Corporate bonds						
Corporate bonds	707	13	720	701	7	708
Asset-backed securities	126	1	127	129	—	129
Mortgage-backed debt securities						
U.S. governmental agency	283	5	288	291	1	292
Residential	11	—	11	12	—	12
Commercial	58	2	60	59	2	61
Equity securities						
Large capitalization value	242	35	277	243	30	273
Real estate investment trust (REIT)	50	1	51	25	—	25
Smaller company growth	37	15	52	37	17	54
Total	$1,598	$ 72	$1,670	$1,577	$ 58	$1,635

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Available-for-sale investments in an unrealized loss position that are not other-than-temporarily impaired:

	March 31, 2016					
	Less than 12 months [1]		12 months or more [1]		Total	
(Millions of dollars)	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
Corporate bonds						
Corporate bonds	$64	$ 1	$27	$ —	$91	$ 1
Asset-backed securities	15	—	9	1	24	1
Equity securities						
Large capitalization value	76	9	5	1	81	10
Small company growth	10	2	1	—	11	2
Total	$165	$ 12	$42	$ 2	$207	$ 14

	December 31, 2015					
	Less than 12 months [1]		12 months or more [1]		Total	
(Millions of dollars)	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
Corporate bonds						
Corporate bonds	$242	$ 3	$27	$ 1	$269	$ 4
Asset-backed securities	84	1	10	1	94	2
Mortgage-backed debt securities						
U.S. governmental agency	135	1	57	1	192	2
Equity securities						
Large capitalization value	97	8	2	—	99	8
Smaller company growth	14	1	—	—	14	1
Total	$572	$ 14	$96	$ 3	$668	$ 17

[1] Indicates length of time that individual securities have been in a continuous unrealized loss position.

Corporate Bonds. The unrealized losses on our investments in corporate bonds and asset-backed securities relate to changes in interest rates and credit-related yield spreads since time of purchase. We do not intend to sell the investments and it is not likely that we will be required to sell the investments before recovery of their amortized cost basis. We do not consider these investments to be other-than-temporarily impaired as of March 31, 2016.

Equity Securities. The unrealized losses on our investments in equity securities relate to inherent risks of individual holdings and/or their respective sectors. We do not consider these investments to be other-than-temporarily impaired as of March 31, 2016.

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The cost basis and fair value of the available-for-sale debt securities at March 31, 2016, by contractual maturity, is shown below. Expected maturities will differ from contractual maturities because borrowers may have the right to prepay and creditors may have the right to call obligations.

(Millions of dollars)	March 31, 2016 Cost Basis	Fair Value
Due in one year or less	$168	$169
Due after one year through five years	667	679
Due after five years through ten years	54	55
Due after ten years	28	28
U.S. governmental agency mortgage-backed securities	283	288
Residential mortgage-backed securities	11	11
Commercial mortgage-backed securities	58	60
Total debt securities – available-for-sale	$1,269	$1,290

Sales of Securities:

(Millions of dollars)	Three Months Ended March 31 2016	2015
Proceeds from the sale of available-for-sale securities	$49	$ 83
Gross gains from the sale of available-for-sale securities	$1	$ 5
Gross losses from the sale of available-for-sale securities	$1	$ 1

9. Postretirement benefits

A. Pension and postretirement benefit costs

At December 31, 2015, we changed our method for calculating the service and interest cost components of net periodic benefit cost. Historically, these components were determined utilizing a single weighted-average discount rate based on the yield curve used to measure the benefit obligation at the beginning of the period. Beginning in 2016, we elected to utilize a full yield curve approach in the estimation of service and interest costs by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to the relevant projected cash flows. We made this change to provide a more precise measurement of service and interest costs by improving the correlation between the projected cash flows to the corresponding spot rates along the yield curve. This change will have no impact on our year-end pension and other postretirement liabilities and has been accounted for prospectively as a change in accounting estimate beginning in the first quarter of 2016. The discount rates used to measure the 2016 service and interest cost components of net periodic benefit cost are provided in the table below. Under the previous method the discount rate used for these components of cost would have been 4.2 percent for U.S. pensions, 3.2 percent for non-U.S. pensions and 4.1 percent for other postretirement benefits (OPEB). Compared to the method used in 2015, this change lowered pension and OPEB expense by $45 million and increased profit per share by $0.06 for the three months ended March 31, 2016.

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(Millions of dollars)	U.S. Pension Benefits		Non-U.S. Pension Benefits		Other Postretirement Benefits	
	March 31		March 31		March 31	
	2016	2015	2016	2015	2016	2015
For the three months ended:						
Components of net periodic benefit cost:						
Service cost	$30	$46	$23	$29	$20	$25
Interest cost	129	151	30	39	33	46
Expected return on plan assets	(189)	(224)	(58)	(69)	(11)	(14)
Amortization of prior service cost (credit) [1]	—	—	—	—	(15)	(13)
Net periodic benefit cost (benefit)	(30)	(27)	(5)	(1)	27	44
Curtailments and termination benefits [2]	—	—	—	—	(2)	—
Total cost (benefit) included in operating profit	$(30)	$(27)	$(5)	$(1)	$25	$44
Weighted-average assumptions used to determine net cost:						
Discount rate used to measure service cost	4.5 %	3.8 %	2.9 %	3.3 %	4.4 %	3.9 %
Discount rate used to measure interest cost	3.4 %	3.8 %	2.8 %	3.3 %	3.3 %	3.9 %
Expected rate of return on plan assets	6.9 %	7.4 %	6.1 %	6.8 %	7.5 %	7.8 %
Rate of compensation increase	4.0 %	4.0 %	3.5 %	4.0 %	4.0 %	4.0 %

1 Prior service cost (credit) for both pension and other postretirement benefits are generally amortized using the straight-line method over the average remaining service period of active employees expected to receive benefits from the plan. For pension plans in which all or almost all of the plan's participants are inactive and other postretirement benefit plans in which all or almost all of the plan's participants are fully eligible for benefits under the plan, prior service cost (credit) are amortized using the straight-line method over the remaining life expectancy of those participants.

2 Curtailments and termination benefits were recognized in Other operating (income) expenses in the Consolidated Statement of Results of Operations.

We made $63 million of contributions to our pension plans during the three months ended March 31, 2016. We currently anticipate full-year 2016 contributions of approximately $150 million, all of which are required. We made $77 million of contributions to our pension plans during the three months ended March 31, 2015.

B. Defined contribution benefit costs

Total company costs related to our defined contribution plans were as follows:

(Millions of dollars)	Three Months Ended March 31	
	2016	2015
U.S. Plans	$85	$83
Non-U.S. Plans	18	18

$103	$101

10. Guarantees and product warranty

Caterpillar dealer performance guarantees

We have provided an indemnity to a third-party insurance company for potential losses related to performance bonds issued on behalf of Caterpillar dealers. The bonds have varying terms and are issued to insure governmental agencies against nonperformance by certain dealers. We also provided guarantees to third-parties related to the performance of contractual obligations by certain Caterpillar dealers. These guarantees have varying terms and cover potential financial losses incurred by the third-parties resulting from the dealers' nonperformance.

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Customer loan guarantees
We provide loan guarantees to third-party lenders for financing associated with machinery purchased by customers. These guarantees have varying terms and are secured by the machinery. In addition, Cat Financial participates in standby letters of credit issued to third parties on behalf of their customers. These standby letters of credit have varying terms and beneficiaries and are secured by customer assets.

Supplier consortium performance guarantee
We have provided a guarantee to one of our customers in Brazil related to the performance of contractual obligations by a supplier consortium to which one of our Caterpillar subsidiaries is a member. The guarantee covers potential damages (some of them capped) incurred by the customer resulting from the supplier consortium's non-performance. The guarantee will expire when the supplier consortium performs all its contractual obligations, which is expected to be completed in 2025.

Third party logistics business lease guarantees
We have provided guarantees to third-party lessors for certain properties leased by a third party logistics business, formerly Caterpillar Logistics Services LCC, in which we sold our 35 percent equity interest in the first quarter of 2015 (see Note 6). The guarantees are for the possibility that the third party logistics business would default on real estate lease payments. The guarantees were granted at lease inception and generally will expire at the end of the lease terms.

No significant loss has been experienced or is anticipated under any of these guarantees. At March 31, 2016 and December 31, 2015, the related liability was $12 million. The maximum potential amount of future payments (undiscounted and without reduction for any amounts that may possibly be recovered under recourse or collateralized provisions) we could be required to make under the guarantees are as follows:

(Millions of dollars)	March 31, 2016	December 31, 2015
Caterpillar dealer performance guarantees	$ 224	$ 216
Customer loan guarantees	61	47
Supplier consortium performance guarantee	299	286
Third party logistics business lease guarantees	107	107
Other guarantees	26	25
Total guarantees	$ 717	$ 681

Cat Financial provides guarantees to repurchase certain loans of Caterpillar dealers from a special-purpose corporation (SPC) that qualifies as a variable interest entity. The purpose of the SPC is to provide short-term working capital loans to Caterpillar dealers. This SPC issues commercial paper and uses the proceeds to fund its loan program. Cat Financial has a loan purchase agreement with the SPC that obligates Cat Financial to purchase certain loans that are not paid at maturity. Cat Financial receives a fee for providing this guarantee, which provides a source of liquidity for the SPC. Cat Financial is the primary beneficiary of the SPC as its guarantees result in Cat Financial having both the power to direct the activities that most significantly impact the SPC's economic performance and the obligation to absorb losses, and therefore Cat Financial has consolidated the financial statements of the SPC. As of March 31, 2016 and December 31, 2015, the SPC's assets of $1,230 million and $1,211 million, respectively, are primarily comprised of loans to dealers and the SPC's liabilities of $1,229 million and $1,210 million, respectively, are primarily comprised of commercial paper. The assets of the SPC are not available to pay Cat Financial's creditors. Cat Financial may be obligated to perform under the guarantee if the SPC experiences losses. No loss has been experienced or is anticipated under this loan purchase agreement.

Our product warranty liability is determined by applying historical claim rate experience to the current field population and dealer inventory. Generally, historical claim rates are based on actual warranty experience for each product by machine model/engine size by customer or dealer location (inside or outside North America). Specific rates are developed for each product shipment month and are updated monthly based on actual warranty claim experience.

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(Millions of dollars)	2016
Warranty liability, January 1	$1,354
Reduction in liability (payments)	(220)
Increase in liability (new warranties)	219
Warranty liability, March 31	$1,353

(Millions of dollars)	2015
Warranty liability, January 1	$1,426
Reduction in liability (payments)	(874)
Increase in liability (new warranties)	802
Warranty liability, December 31	$1,354

11. Profit per share

Computations of profit per share: (Dollars in millions except per share data)	Three Months Ended March 31	
	2016	2015
Profit for the period (A) [1]	$271	$1,245
Determination of shares (in millions):		
Weighted-average number of common shares outstanding (B)	582.8	604.9
Shares issuable	4.9	7.8

on exercise of stock awards, net of shares assumed to be purchased out of proceeds at average market price		
Average common shares outstanding for fully diluted computation (C) [2]	587.7	612.7
Profit per share of common stock:		
Assuming no dilution (A/B)	$ 0.46	$ 2.06
Assuming full dilution (A/C) [2]	$ 0.46	$ 2.03
Shares outstanding as of March 31 (in millions)	583.9	603.6

[1] Profit attributable to common stockholders.
[2] Diluted by assumed exercise of stock-based compensation awards using the treasury stock method.

SARs and stock options to purchase 29,093,289 and 22,360,627 common shares were outstanding for the three months ended March 31, 2016 and 2015, respectively, which were not included in the computation of diluted earnings per share because the effect would have been anti-dilutive.

In January 2014, the Board authorized the repurchase of up to $10.0 billion of Caterpillar common stock, which will expire on December 31, 2018. During the first quarter of 2015, a total of approximately 4.8 million shares of our common stock were repurchased through the open market at an aggregate cost to Caterpillar of $400 million. Through the end of the first quarter of 2016, approximately $4.5 billion of the $10.0 billion authorization was spent.

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12. Accumulated other comprehensive income (loss)

Comprehensive income and its components are presented in the Consolidated Statement of Comprehensive Income. Changes in Accumulated other comprehensive income (loss), net of tax, included in the Consolidated Statement of Changes in Stockholders' Equity, consisted of the following:

(Millions of dollars)	Foreign currency translation	Pension and other postretirement benefits	Derivative financial instruments	Available-for-sale securities	Total
Three Months Ended March 31, 2016					
Balance at December 31, 2015	$ (1,953)	$ (69)	$ (50)	$ 37	$ (2,035)
Other comprehensive income (loss) before reclassifications	408	118	9	6	541
Amounts reclassified from accumulated other comprehensive (income) loss	—	(10)	9	2	1
Other comprehensive income (loss)	408	108	18	8	542
Balance at March 31, 2016	$ (1,545)	$ 39	$ (32)	$ 45	$ (1,493)
Three Months Ended March 31, 2015					
Balance at December 31, 2014	$ (992)	$ (31)	$ (119)	$ 83	$ (1,059)
Other comprehensive income (loss) before reclassifications	(786)	—	(14)	8	(792)
Amounts reclassified from accumulated other comprehensive (income) loss	—	(9)	24	(2)	13
Other comprehensive income (loss)	(786)	(9)	10	6	(779)
Balance at March 31, 2015	$ (1,778)	$ (40)	$ (109)	$ 89	$ (1,838)

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The effect of the reclassifications out of Accumulated other comprehensive income (loss) on the Consolidated Statement of Results of Operations is as follows:

(Millions of dollars)	Classification of income (expense)	Three Months Ended March 31 2016	2015
Pension and other postretirement benefits:			
Amortization of prior service credit (cost)	Note 9 [1]	$15	$13
Tax (provision) benefit		(5)	(4)
Reclassifications net of tax		$10	$9
Derivative financial instruments:			
Foreign exchange contracts	Other income (expense)	$(10)	$(35)
Interest rate contracts	Interest expense excluding Financial Products	(2)	(2)
Interest rate contracts	Interest expense of Financial Products	(2)	(1)
Reclassifications before tax		(14)	(38)
Tax (provision) benefit		5	14
Reclassifications net of tax		$(9)	$(24)
Available-for-sale securities:			
Realized gain (loss)	Other income (expense)	$(3)	$3
Tax (provision) benefit		1	(1)
Reclassifications net of tax		$(2)	$2
Total reclassifications from Accumulated other comprehensive income (loss)		$(1)	$(13)

[1] Amounts are included in the calculation of net periodic benefit cost. See Note 9 for additional information.

13. Environmental and legal matters

The Company is regulated by federal, state and international environmental laws governing our use, transport and disposal of substances and control of emissions. In addition to governing our manufacturing and other operations, these laws often impact the development of our products, including, but not limited to, required compliance with air emissions standards applicable to internal combustion engines. We have made, and will continue to make, significant research and development and capital expenditures to comply with these emissions standards.

We are engaged in remedial activities at a number of locations, often with other companies, pursuant to federal and state laws. When it is probable we will pay remedial costs at a site, and those costs can be reasonably estimated, the investigation, remediation, and operating and maintenance costs are accrued against our earnings. Costs are accrued based on consideration of currently available data and information with respect to each individual site, including available technologies, current applicable laws and regulations, and prior remediation experience. Where no amount within a range of estimates is more likely, we accrue the minimum. Where multiple potentially responsible parties are involved, we consider our proportionate share of the probable costs. In formulating the estimate of probable costs, we do not consider amounts expected to be recovered from insurance companies or others. We reassess these accrued amounts on a quarterly basis. The amount recorded for environmental remediation is not material and is included in Accrued expenses. We believe there is no more than a remote chance that a material amount for remedial activities at any individual site, or at all the sites in the aggregate, will be required.

On January 8, 2015, the Company received a grand jury subpoena from the U.S. District Court for the Central District of Illinois. The subpoena requests documents and information from the Company relating to, among other things, financial information concerning U.S. and non-U.S. Caterpillar subsidiaries (including undistributed profits of non-U.S.

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subsidiaries and the movement of cash among U.S. and non-U.S. subsidiaries). The Company has received additional subpoenas relating to this investigation requesting additional documents and information relating to, among other things, the purchase and resale of replacement parts by Caterpillar Inc. and non-U.S. Caterpillar subsidiaries, dividend distributions of certain non-U.S. Caterpillar subsidiaries, and Caterpillar SARL and related structures. The Company is cooperating with this investigation. The Company is unable to predict the outcome or reasonably estimate any potential loss; however, we currently believe that this matter will not have a material adverse effect on the Company's consolidated results of operations, financial position or liquidity.

On September 10, 2014, the SEC issued to Caterpillar a subpoena seeking information concerning the Company's accounting for the goodwill relating to its acquisition of Bucyrus International Inc. in 2011 and related matters. The Company has received additional subpoenas relating to this investigation, and the Company is cooperating with the SEC regarding its ongoing investigation. The Company is unable to predict the outcome or reasonably estimate any potential loss; however, we currently believe that this matter will not have a material adverse effect on the Company's consolidated results of operations, financial position or liquidity.

On March 20, 2014, Brazil's Administrative Council for Economic Defense (CADE) published a Technical Opinion which named 18 companies and over 100 individuals as defendants, including two subsidiaries of Caterpillar Inc., MGE - Equipamentos e Serviços Ferroviários Ltda. (MGE) and Caterpillar Brasil Ltda. The publication of the Technical Opinion opened CADE's official administrative investigation into allegations that the defendants participated in anticompetitive bid activity for the construction and maintenance of metro and train networks in Brazil. While companies cannot be held criminally liable for anticompetitive conduct in Brazil, criminal charges have been brought against two current employees of MGE and one former employee of MGE involving the same conduct alleged by CADE. The Company has responded to all requests for information from the authorities. The Company is unable to predict the outcome or reasonably estimate the potential loss; however, we currently believe that this matter will not have a material adverse effect on the Company's consolidated results of operations, financial position or liquidity.

On October 24, 2013, Progress Rail received a grand jury subpoena from the U.S. District Court for the Central District of California. The subpoena requests documents and information from Progress Rail, United Industries Corporation, a wholly-owned subsidiary of Progress Rail, and Caterpillar Inc. relating to allegations that Progress Rail conducted improper or unnecessary railcar inspections and repairs and improperly disposed of parts, equipment, tools and other items. In connection with this subpoena, Progress Rail was informed by the U.S. Attorney for the Central District of California that it is a target of a criminal investigation into potential violations of environmental laws and alleged improper business practices. The Company is cooperating with the authorities and is currently in discussions regarding a potential resolution of the matter. Although the Company believes a loss is probable, we currently believe that this matter will not have a material adverse effect on the Company's consolidated results of operations, financial position or liquidity.

In addition, we are involved in other unresolved legal actions that arise in the normal course of business. The most prevalent of these unresolved actions involve disputes related to product design, manufacture and performance liability (including claimed asbestos and welding fumes exposure), contracts, employment issues, environmental matters or intellectual property rights. The aggregate range of reasonably possible losses in excess of accrued liabilities, if any, associated with these unresolved legal actions is not material. In some cases, we cannot reasonably estimate a range of loss because there is insufficient information regarding the matter. However, we believe there is no more than a remote chance that any liability arising from these matters would be material. Although it is not possible to predict with certainty the outcome of these unresolved legal actions, we believe that these actions will not individually or in the aggregate have a material adverse effect on our consolidated results of operations, financial position or liquidity.

14. Income taxes

The provision for income taxes in the first quarter reflects an estimated annual tax rate of 25 percent, compared to 29.5 percent for the first quarter of 2015 and 25.5 percent for the full-year 2015 excluding a $42 million discrete tax charge. The full-year rate for 2015 of 25.5 percent was lower than the first-quarter 2015 rate, primarily due to changes in the geographic mix of profits from a tax perspective along with the impact of the permanent renewal of the U.S. research and development tax credit in the fourth quarter.

On January 30, 2015, we received a Revenue Agent's Report (RAR) from the Internal Revenue Service (IRS) indicating the end of the field examination of our U.S. tax returns for 2007 to 2009 including the impact of a loss carryback to 2005. The RAR proposed tax increases and penalties for these years of approximately $1 billion primarily related to two significant areas that we are vigorously contesting through the IRS Appeals process. In the first area, the IRS has proposed to tax in the United States profits earned from certain parts transactions by one of our non-U.S. subsidiaries, Caterpillar SARL (CSARL), based on the IRS examination team's application of the "substance-over-form" or "assignment-of-income" judicial doctrines. We believe that the relevant transactions complied with applicable tax laws and did not violate judicial doctrines. We have filed U.S. tax returns on this same basis for years after 2009. In the second area, the IRS disallowed approximately $125 million of foreign tax credits that arose as a result of certain financings unrelated to CSARL. Based on the information currently available, we do not anticipate a significant increase or decrease to our unrecognized tax benefits for these matters within the next 12 months. We currently believe the ultimate disposition of these matters will not have a material adverse effect on our consolidated financial position, liquidity or results of operations.

15. Segment information

A. Basis for segment information

Our Executive Office is comprised of five Group Presidents, a Senior Vice President, an Executive Vice President and a CEO. Group Presidents are accountable for a related set of end-to-end businesses that they manage. The Senior Vice President leads the Caterpillar Enterprise System Group and the Executive Vice President leads the Law and Public Policy Division. The CEO allocates resources and manages performance at the Group President level. As such, the CEO serves as our Chief Operating Decision Maker and operating segments are primarily based on the Group President reporting structure.

Three of our operating segments, Construction Industries, Resource Industries and Energy & Transportation are led by Group Presidents. One operating segment, Financial Products, is led by a Group President who also has responsibility for Corporate Services. Corporate Services is a cost center primarily responsible for the performance of certain support functions globally and to provide centralized services; it does not meet the definition of an operating segment. One Group President leads two smaller operating segments that are included in the All Other operating segments. The Caterpillar Enterprise System Group and Law and Public Policy Division are cost centers and do not meet the definition of an operating segment.

Effective January 1, 2016, we made the following changes to segment reporting. These changes were made to reflect changes in organizational accountabilities and refinements to our internal reporting.

- Responsibility for remanufacturing of Cat engines and components and remanufacturing services for other companies moved from the All Other operating segments to Energy & Transportation.
- Responsibility for business strategy, product management, development, manufacturing, marketing and product support for forestry and paving products moved from the All Other operating segments to Construction Industries.
- Responsibility for business strategy, product management, development, manufacturing, marketing and product support for industrial and waste products moved from the All Other operating segments to Resource Industries.
- Responsibility for sales and product support of on-highway vocational trucks for North America moved from the All Other operating segments to Energy & Transportation.
- Internal charges for component manufacturing and logistics services provided by All Other operating segments to Construction Industries, Resource Industries and Energy & Transportation in excess of cost have been adjusted to approximate cost, resulting in a reduction in profit in the All Other operating segments and corresponding increases in profit in the other three segments.
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Costs that previously had been included in Corporate costs, primarily for company-wide strategies such as information technology and manufacturing process transformation, have been included in the ME&T operating segments that benefit from the costs.

Segment information for 2015 has been retrospectively adjusted to conform to the 2016 presentation.

B. Description of segments

We have six operating segments, of which four are reportable segments. Following is a brief description of our reportable segments and the business activities included in the All Other operating segments:

Construction Industries: A segment primarily responsible for supporting customers using machinery in infrastructure, forestry and building construction applications. Responsibilities include business strategy, product design, product management and development, manufacturing, marketing and sales and product support. The product portfolio includes backhoe loaders, small wheel loaders, small track-type tractors, skid steer loaders, multi-terrain loaders, mini excavators, compact wheel loaders, telehandlers, select work tools, small, medium and large track excavators, wheel excavators, medium wheel loaders, compact track loaders, medium track-type tractors, track-type loaders, motor graders, pipelayers, forestry products, paving products and related parts. In addition, Construction Industries has responsibility for an integrated manufacturing cost center. Inter-segment sales are a source of revenue for this segment.

Resource Industries: A segment primarily responsible for supporting customers using machinery in mining, quarry, waste, and material handling applications. Responsibilities include business strategy, product design, product management and development, manufacturing, marketing and sales and product support. The product portfolio includes large track-type tractors, large mining trucks, hard rock vehicles, longwall miners, electric rope shovels, draglines, hydraulic shovels, track and rotary drills, highwall miners, large wheel loaders, off-highway trucks, articulated trucks, wheel tractor scrapers, wheel dozers, landfill compactors, soil compactors, material handlers, continuous miners, scoops and haulers, hardrock continuous mining systems, select work tools, machinery components, electronics and control systems and related parts. Resource Industries also manages areas that provide services to other parts of the company, including integrated manufacturing and research and development. Inter-segment sales are a source of revenue for this segment.

Energy & Transportation: A segment primarily responsible for supporting customers using reciprocating engines, turbines, diesel-electric locomotives and related parts across industries serving power generation, industrial, oil and gas and transportation applications, including marine and rail-related businesses. Responsibilities include business strategy, product design, product management, development, manufacturing, marketing, sales and product support of turbines and turbine-related services, reciprocating engine powered generator sets, integrated systems used in the electric power generation industry, reciprocating engines and integrated systems and solutions for the marine and oil and gas industries; reciprocating engines supplied to the industrial industry as well as Cat machinery; the remanufacturing of Cat engines and components and remanufacturing services for other companies; the business strategy, product design, product management, development, manufacturing, remanufacturing, leasing and service of diesel-electric locomotives and components and other rail-related products and services and product support of on-highway vocational trucks for North America. Inter-segment sales are a source of revenue for this segment.

Financial Products Segment: Provides financing to customers and dealers for the purchase and lease of Caterpillar and other equipment, as well as some financing for Caterpillar sales to dealers. Financing plans include operating and finance leases, installment sale contracts, working capital loans and wholesale financing plans. The segment also provides various forms of insurance to customers and dealers to help support the purchase and lease of our equipment.

All Other operating segments: Primarily includes activities such as: the business strategy, product management, development, and manufacturing of filters and fluids, undercarriage, tires and rims, ground engaging tools, fluid transfer products, precision seals and rubber, and sealing and connecting components primarily for Cat products; parts distribution; distribution services responsible for dealer development and administration including a wholly-owned dealer in Japan, dealer portfolio management and ensuring the most efficient and effective distribution of machines, engines and parts; digital investments for new customer and dealer solutions that integrate data analytics with state-of-the art digital technologies while transforming the buying experience. Results for the All Other operating segments are included as a reconciling item between reportable segments and consolidated external reporting.

C. Segment measurement and reconciliations

There are several methodology differences between our segment reporting and our external reporting. The following is a list of the more significant methodology differences:

- Machinery, Energy & Transportation segment net assets generally include inventories, receivables, property, plant and equipment, goodwill, intangibles, accounts payable, and customer advances. Liabilities other than accounts payable and customer advances are generally managed at the corporate level and are not included in segment operations. Financial Products Segment assets generally include all categories of assets.

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- Segment inventories and cost of sales are valued using a current cost methodology.

- Goodwill allocated to segments is amortized using a fixed amount based on a 20 year useful life. This methodology difference only impacts segment assets; no goodwill amortization expense is included in segment profit. In addition, only a portion of goodwill for certain acquisitions made in 2011 or later has been allocated to segments.

- The present value of future lease payments for certain Machinery, Energy & Transportation operating leases is included in segment assets. The estimated financing component of the lease payments is excluded.

- Currency exposures for Machinery, Energy & Transportation are generally managed at the corporate level and the effects of changes in exchange rates on results of operations within the year are not included in segment profit. The net difference created in the translation of revenues and costs between exchange rates used for U.S. GAAP reporting and exchange rates used for segment reporting is recorded as a methodology difference.

- Stock-based compensation expense is not included in segment profit.

- Postretirement benefit expenses are split; segments are generally responsible for service and prior service costs, with the remaining elements of net periodic benefit cost included as a methodology difference.

- Machinery, Energy & Transportation segment profit is determined on a pretax basis and excludes interest expense and other income/expense items. Financial Products Segment profit is determined on a pretax basis and includes other income/expense items.

Reconciling items are created based on accounting differences between segment reporting and our consolidated external reporting. Please refer to pages 35 to 39 for financial information regarding significant reconciling items. Most of our reconciling items are self-explanatory given the above explanations. For the reconciliation of profit, we have grouped the reconciling items as follows:

- Corporate costs: These costs are related to corporate requirements primarily for compliance and legal functions for the benefit of the entire organization.

- Restructuring costs: Primarily costs for employee separation costs, long-lived asset impairments and contract terminations. These costs are included in Other Operating (Income) Expenses. Restructuring costs also include other exit-related costs primarily for accelerated depreciation, equipment relocation, inventory write-downs and sales discounts and payments to dealers and customers related to discontinued products. A table, Reconciliation of Restructuring costs on page 37, has been included to illustrate how segment profit would have been impacted by the restructuring costs. See Note 18 for more information.

- Methodology differences: See previous discussion of significant accounting differences between segment reporting and consolidated external reporting.

- Timing: Timing differences in the recognition of costs between segment reporting and consolidated external reporting. For example, certain costs are reported on the cash basis for segment reporting and the accrual basis for consolidated external reporting.

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Reportable Segments
Three Months Ended March 31
(Millions of dollars)

2016	External sales and revenues	Inter-segment sales and revenues	Total sales and revenues	Depreciation and amortization	Segment profit	Segment assets at March 31	Capital expenditures
Construction Industries	$4,043	$ 8	$4,051	$ 113	$440	$ 5,840	$ 28
Resource Industries	1,449	71	1,520	155	(96)	8,448	35
Energy & Transportation	3,278	632	3,910	166	410	8,131	147
Machinery, Energy & Transportation	$8,770	$ 711	$9,481	$ 434	$754	$ 22,419	$ 210
Financial Products Segment	743	—	743	205	168	37,236	297
Total	$9,513	$ 711	$10,224	$ 639	$922	$ 59,655	$ 507

2015	External sales and revenues	Inter-segment sales and revenues	Total sales and revenues	Depreciation and amortization	Segment profit	Segment assets at December 31	Capital expenditures
Construction Industries	$5,014	$ 23	$5,037	$ 140	$745	$ 6,176	$ 40
Resource Industries	1,971	87	2,058	147	96	8,931	35
Energy & Transportation	4,915	794	5,709	167	1,024	8,769	159
Machinery, Energy & Transportation	$11,900	$ 904	$12,804	$ 454	$1,865	$ 23,876	$ 234
Financial Products Segment	795	—	795	215	227	35,729	294
Total	$12,695	$ 904	$13,599	$ 669	$2,092	$ 59,605	$ 528

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Reconciliation of Sales and revenues:

(Millions of dollars)	Machinery, Energy & Transportation	Financial Products	Consolidating Adjustments	Consolidated Total
Three Months Ended March 31, 2016				
Total external sales and revenues from reportable segments	$ 8,770	$ 743	$ —	$ 9,513
All Other operating segments	38	—	—	38
Other	(28)	16	(78) [1]	(90)
Total sales and revenues	$ 8,780	$ 759	$ (78)	$ 9,461
Three Months Ended March 31, 2015				
Total external sales and revenues from reportable segments	$ 11,900	$ 795	$ —	$ 12,695
All Other operating segments	72	—	—	72
Other	(11)	18	(72) [1]	(65)
Total sales and revenues	$ 11,961	$ 813	$ (72)	$ 12,702

[1] Elimination of Financial Products revenues from Machinery, Energy & Transportation.

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Reconciliation of Consolidated profit before taxes:

(Millions of dollars)	Machinery, Energy & Transportation	Financial Products	Consolidated Total
Three Months Ended March 31, 2016			
Total profit from reportable segments	$ 754	$ 168	$ 922
All Other operating segments	(7)	—	(7)
Cost centers	25	—	25
Corporate costs	(159)	—	(159)
Timing	32	—	32
Restructuring costs	(159)	(2)	(161)
Methodology differences:			
Inventory/cost of sales	(3)	—	(3)
Postretirement benefit expense	55	—	55
Stock-based compensation expense	(97)	(4)	(101)
Financing costs	(135)	—	(135)
Equity in (profit) loss of unconsolidated affiliated companies	2	—	2
Currency	(40)	—	(40)
Other income/expense methodology differences	(56)	—	(56)
Other methodology differences	(14)	5	(9)
Total consolidated profit before taxes	$ 198	$ 167	$ 365
Three Months Ended March 31, 2015			
Total profit from reportable segments	$ 1,865	$ 227	$ 2,092
All Other operating segments	(7)	—	(7)
Cost centers	18	—	18
Corporate costs	(140)	—	(140)
Timing	19	—	19
Restructuring costs	(35)	—	(35)
Methodology differences:			—
Inventory/cost of sales	(35)	—	(35)
Postretirement benefit expense	69	—	69
Stock-based compensation expense	(129)	(6)	(135)
Financing costs	(136)	—	(136)
Equity in (profit) loss of unconsolidated affiliated companies	(2)	—	(2)
Currency	10	—	10
Other income/expense methodology differences	59	—	59
Other methodology differences	(18)	8	(10)
Total consolidated profit before taxes	$ 1,538	$ 229	$ 1,767

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Reconciliation of Restructuring costs:

As noted above, restructuring costs are a reconciling item between Segment profit and Consolidated profit before taxes. Had we included the amounts in the segments' results, the profit would have been as shown below:
Reconciliation of Restructuring costs:

(Millions of dollars)	Segment profit	Restructuring costs	Segment profit with restructuring costs
Three Months Ended March 31, 2016			
Construction Industries	$ 440	$ (22)	$ 418
Resource Industries	(96)	(25)	(121)
Energy & Transportation	410	(100)	310
Financial Products Segment	168	(2)	166
All Other operating segments	(7)	(5)	(12)
Total	$ 915	$ (154)	$ 761
Three Months Ended March 31, 2015			
Construction Industries	$ 745	$ (23)	$ 722
Resource Industries	96	(8)	88
Energy & Transportation	1,024	(3)	1,021
Financial Products Segment	227	—	227
All Other operating segments	(7)	(1)	(8)
Total	$ 2,085	$ (35)	$ 2,050

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Reconciliation of Assets:

(Millions of dollars)	Machinery, Energy & Transportation	Financial Products	Consolidating Adjustments	Consolidated Total
March 31, 2016				
Total assets from reportable segments	$ 22,419	$37,236	$ —	$ 59,655
All Other operating segments	1,411	—	—	1,411
Items not included in segment assets:				
Cash and short-term investments	4,744	—	—	4,744
Intercompany receivables	2,107	—	(2,107)	—
Investment in Financial Products	4,194	—	(4,194)	—
Deferred income taxes	3,156	—	(750)	2,406
Goodwill and intangible assets	4,080	—	—	4,080
Property, plant and equipment – net and other assets	2,015	—	—	2,015
Operating lease methodology difference	(201)	—	—	(201)
Inventory methodology differences	(2,263)	—	—	(2,263)
Intercompany loan included in Financial Products' assets	—	—	(1,000)	(1,000)
Liabilities included in segment assets	7,922	—	—	7,922
Other	(313)	(83)	(66)	(462)
Total assets	$ 49,271	$37,153	$ (8,117)	$ 78,307
December 31, 2015				
Total assets from reportable segments	$ 23,876	$35,729	$ —	$ 59,605
All Other operating segments	1,405	—	—	1,405
Items not included in segment assets:				
Cash and short-term investments	5,340	—	—	5,340
Intercompany receivables	1,087	—	(1,087)	—
Investment in Financial Products	3,888	—	(3,888)	—
Deferred income taxes	3,208	—	(793)	2,415
Goodwill and intangible assets	3,571	—	—	3,571
Property, plant and equipment – net and other assets	1,585	—	—	1,585
Operating lease methodology difference	(213)	—	—	(213)
Inventory methodology differences	(2,646)	—	—	(2,646)
Liabilities included in segment assets	8,017	—	—	8,017
Other	(567)	(93)	(77)	(737)
Total assets	$ 48,551	$35,636	$ (5,845)	$ 78,342

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Reconciliations of Depreciation and amortization:

(Millions of dollars)	Machinery, Energy & Transportation	Financial Products	Consolidated Total
Three Months Ended March 31, 2016			
Total depreciation and amortization from reportable segments	$ 434	$ 205	$ 639
Items not included in segment depreciation and amortization:			
All Other operating segments	52	—	52
Cost centers	40	—	40
Other	(1)	10	9
Total depreciation and amortization	$ 525	$ 215	$ 740
Three Months Ended March 31, 2015			
Total depreciation and amortization from reportable segments	$ 454	$ 215	$ 669
Items not included in segment depreciation and amortization:			
All Other operating segments	49	—	49
Cost centers	37	—	37
Other	(10)	8	(2)
Total depreciation and amortization	$ 530	$ 223	$ 753

Reconciliations of Capital expenditures:

(Millions of dollars)	Machinery, Energy & Transportation	Financial Products	Consolidating Adjustments	Consolidated Total
Three Months Ended March 31, 2016				
Total capital expenditures from reportable segments	$ 210	$ 297	$ —	$ 507
Items not included in segment capital expenditures:				
All Other operating segments	16	—	—	16
Cost centers	12	—	—	12
Timing	217	—	—	217
Other	(76)	73	(9)	(12)
Total capital expenditures	$ 379	$ 370	$ (9)	$ 740
Three Months Ended March 31, 2015				
Total capital expenditures from reportable segments	$ 234	$ 294	$ —	$ 528
Items not included in segment capital expenditures:				
All Other operating segments	25	—	—	25
Cost centers	19	—	—	19
Timing	253	—	—	253
Other	(54)	63	(8)	1
Total capital expenditures	$ 477	$ 357	$ (8)	$ 826

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16. Cat Financial financing activities

Allowance for credit losses

The allowance for credit losses is an estimate of the losses inherent in Cat Financial's finance receivable portfolio and includes consideration of accounts that have been individually identified as impaired, as well as pools of finance receivables where it is probable that certain receivables in the pool are impaired but the individual accounts cannot yet be identified. In identifying and measuring impairment, management takes into consideration past loss experience, known and inherent risks in the portfolio, adverse situations that may affect the borrower's ability to repay, estimated value of underlying collateral and current economic conditions.

Accounts are identified for individual review based on past-due status and using information available about the customer, such as financial statements, news reports and published credit ratings, as well as general information regarding industry trends and the economic environment in which Cat Financial's customers operate. The allowance for credit losses attributable to finance receivables that are individually evaluated and determined to be impaired is based either on the present value of expected future cash flows discounted at the receivables' effective interest rate or the fair value of the collateral for collateral-dependent receivables. In determining collateral value, Cat Financial estimates the current fair market value of the collateral less selling costs. Cat Financial also considers credit enhancements such as additional collateral and contractual third-party guarantees. The allowance for credit losses attributable to the remaining accounts not yet individually identified as impaired is estimated based on loss forecast models utilizing probabilities of default, our estimate of the loss emergence period and the estimated loss given default. In addition, qualitative factors not able to be fully captured in the loss forecast models including industry trends, macroeconomic factors and model imprecision are considered in the evaluation of the adequacy of the allowance for credit losses. These qualitative factors are subjective and require a degree of management judgment.

Cat Financial's allowance for credit losses is segregated into two portfolio segments:

- Customer - Finance receivables with retail customers.
- Dealer - Finance receivables with Caterpillar dealers.

A portfolio segment is the level at which the company develops a systematic methodology for determining its allowance for credit losses.

Cat Financial further evaluates portfolio segments by the class of finance receivables, which is defined as a level of information (below a portfolio segment) in which the finance receivables have the same initial measurement attribute and a similar method for assessing and monitoring credit risk. Typically, Cat Financial's finance receivables within a geographic area have similar credit risk profiles and methods for assessing and monitoring credit risk. Cat Financial's classes, which align with management reporting for credit losses, are as follows:

- North America - Finance receivables originated in the United States or Canada.
- Europe - Finance receivables originated in Europe, Africa, Middle East and the Commonwealth of Independent States.
- Asia Pacific - Finance receivables originated in Australia, New Zealand, China, Japan, South Korea and Southeast Asia.
- Mining - Finance receivables related to large mining customers worldwide.
- Latin America - Finance receivables originated in Central and South American countries and Mexico.
- Caterpillar Power Finance - Finance receivables related to marine vessels with Caterpillar engines worldwide and Caterpillar electrical power generation, gas compression and co-generation systems and non-Caterpillar equipment that is powered by these systems worldwide.

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An analysis of the allowance for credit losses was as follows:

(Millions of dollars)	March 31, 2016		
Allowance for Credit Losses:	Customer	Dealer	Total
Balance at beginning of year	$327	$9	$336
Receivables written off	(38)	—	(38)
Recoveries on receivables previously written off	7	—	7
Provision for credit losses	29	(1)	28
Other	5	—	5
Balance at end of period	$330	$8	$338
Individually evaluated for impairment	$58	$—	$58
Collectively evaluated for impairment	272	8	280
Ending Balance	$330	$8	$338
Recorded Investment in Finance Receivables:			
Individually evaluated for impairment	$606	$—	$606
Collectively evaluated for impairment	18,955	3,592	22,547
Ending Balance	$19,561	$3,592	$23,153

(Millions of dollars)	December 31, 2015		
Allowance for Credit Losses:	Customer	Dealer	Total
Balance at beginning of year	$388	$10	$398
Receivables written off	(196)	—	(196)
Recoveries on receivables previously written off	41	—	41
Provision for credit losses	119	(1)	118
Other	(25)	—	(25)
Balance at end of year	$327	$9	$336
Individually evaluated for impairment	$65	$—	$65
Collectively evaluated for impairment	262	9	271
Ending Balance	$327	$9	$336
Recorded Investment in Finance Receivables:			
Individually evaluated for impairment	$601	$—	$601
Collectively evaluated for impairment	18,788	3,570	22,358
Ending Balance	$19,389	$3,570	$22,959

Credit quality of finance receivables

At origination, Cat Financial evaluates credit risk based on a variety of credit quality factors including prior payment experience, customer financial information, credit-rating agency ratings, loan-to-value ratios and other internal metrics. On an ongoing basis, Cat Financial monitors credit quality based on past-due status and collection experience as there is a meaningful correlation between the past-due status of customers and the risk of loss.

In determining past-due status, Cat Financial considers the entire finance receivable balance past due when any installment is over 30 days past due. The tables below summarize the recorded investment of finance receivables by aging category.

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(Millions of dollars)	March 31, 2016 31-60 Days Past Due	61-90 Days Past Due	91+ Days Past Due	Total Past Due	Current	Total Finance Receivables	91+ Still Accruing
Customer							
North America	$62	$29	$30	$ 121	$7,993	$ 8,114	$ 5
Europe	15	11	64	90	2,364	2,454	12
Asia Pacific	34	22	29	85	1,593	1,678	12
Mining	16	13	62	91	1,691	1,782	1
Latin America	54	114	243	411	1,916	2,327	1
Caterpillar Power Finance	5	14	28	47	3,159	3,206	—
Dealer							
North America	—	—	—	—	2,226	2,226	—
Europe	—	—	—	—	145	145	—
Asia Pacific	—	—	—	—	604	604	—
Mining	—	—	—	—	4	4	—
Latin America	—	—	—	—	610	610	—
Caterpillar Power Finance	—	—	—	—	3	3	—
Total	$186	$203	$456	$ 845	$22,308	$ 23,153	$ 31

(Millions of dollars)	December 31, 2015 31-60 Days Past Due	61-90 Days Past Due	91+ Days Past Due	Total Past Due	Current	Total Finance Receivables	91+ Still Accruing
Customer							
North America	$45	$ 12	$30	$ 87	$7,850	$ 7,937	$ 4
Europe	18	7	44	69	2,358	2,427	9
Asia Pacific	21	12	21	54	1,647	1,701	6
Mining	6	1	68	75	1,793	1,868	1
Latin America	45	31	199	275	1,998	2,273	—
Caterpillar Power Finance	—	1	35	36	3,147	3,183	2
Dealer							
North America	—	—	—	—	2,209	2,209	—
Europe	—	—	—	—	149	149	—
Asia Pacific	—	—	—	—	552	552	—
Mining	—	—	—	—	4	4	—
Latin America	—	—	—	—	653	653	—
Caterpillar Power Finance	—	—	—	—	3	3	—
Total	$135	$ 64	$397	$ 596	$22,363	$ 22,959	$ 22

Impaired finance receivables

For all classes, a finance receivable is considered impaired, based on current information and events, if it is probable that Cat Financial will be unable to collect all amounts due according to the contractual terms. Impaired finance receivables include finance receivables that have been restructured and are considered to be troubled debt restructurings.

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There were no impaired finance receivables as of March 31, 2016 or December 31, 2015, for the Dealer portfolio segment. Cat Financial's recorded investment in impaired finance receivables and the related unpaid principal balances and allowance for the Customer portfolio segment were as follows:

(Millions of dollars)	March 31, 2016			December 31, 2015		
	Recorded Investment	Unpaid Principal Balance	Related Allowance	Recorded Investment	Unpaid Principal Balance	Related Allowance
Impaired Finance Receivables With No Allowance Recorded						
North America	$20	$ 20	$ —	$12	$ 12	$ —
Europe	39	39	—	41	41	—
Asia Pacific	4	4	—	1	1	—
Mining	79	79	—	84	84	—
Latin America	27	27	—	28	28	—
Caterpillar Power Finance	268	267	—	242	241	—
Total	$437	$ 436	$ —	$408	$ 407	$ —
Impaired Finance Receivables With An Allowance Recorded						
North America	$15	$ 13	$ 4	$14	$ 13	$ 4
Europe	11	11	6	11	10	5
Asia Pacific	35	35	5	34	34	4
Mining	11	11	4	11	11	3
Latin America	53	53	22	53	53	21
Caterpillar Power Finance	44	44	17	70	70	28
Total	$169	$ 167	$ 58	$193	$ 191	$ 65
Total Impaired Finance Receivables						
North America	$35	$ 33	$ 4	$26	$ 25	$ 4
Europe	50	50	6	52	51	5
Asia Pacific	39	39	5	35	35	4
Mining	90	90	4	95	95	3
Latin America	80	80	22	81	81	21
Caterpillar Power Finance	312	311	17	312	311	28
Total	$606	$ 603	$ 58	$601	$ 598	$ 65

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(Millions of dollars)	Three Months Ended March 31, 2016 Average Recorded Investment	Three Months Ended March 31, 2016 Interest Income Recognized	Three Months Ended March 31, 2015 Average Recorded Investment	Three Months Ended March 31, 2015 Interest Income Recognized
Impaired Finance Receivables With No Allowance Recorded				
North America	$ 14	$ —	$ 14	$ —
Europe	40	—	44	—
Asia Pacific	2	—	3	—
Mining	81	1	102	2
Latin America	27	—	32	—
Caterpillar Power Finance	253	3	135	1
Total	$ 417	$ 4	$ 330	$ 3
Impaired Finance Receivables With An Allowance Recorded				
North America	$ 14	$ —	$ 6	$ —
Europe	12	—	14	—
Asia Pacific	33	1	26	—
Mining	11	—	63	1
Latin America	51	1	46	1
Caterpillar Power Finance	59	—	128	—
Total	$ 180	$ 2	$ 283	$ 2
Total Impaired Finance Receivables				
North America	$ 28	$ —	$ 20	$ —
Europe	52	—	58	—
Asia Pacific	35	1	29	—
Mining	92	1	165	3
Latin America	78	1	78	1
Caterpillar Power Finance	312	3	263	1
Total	$ 597	$ 6	$ 613	$ 5

Recognition of income is suspended and the finance receivable is placed on non-accrual status when management determines that collection of future income is not probable (generally after 120 days past due). Recognition is resumed and previously suspended income is recognized when the finance receivable becomes current and collection of remaining amounts is considered probable. Payments received while the finance receivable is on non-accrual status are applied to interest and principal in accordance with the contractual terms.

As of March 31, 2016 and December 31, 2015, there were no finance receivables on non-accrual status for the Dealer portfolio segment.

The investment in customer finance receivables on non-accrual status was as follows:

(Millions of dollars)	March 31, 2016	December 31, 2015
North America	$ 40	$ 31
Europe	56	39
Asia Pacific	18	15

Mining	135	106
Latin America	262	217
Caterpillar Power Finance	57	77
Total	$ 568	$ 485

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Troubled Debt Restructurings

A restructuring of a finance receivable constitutes a troubled debt restructuring (TDR) when the lender grants a concession it would not otherwise consider to a borrower experiencing financial difficulties. Concessions granted may include extended contract maturities, inclusion of interest only periods, below market interest rates, extended skip payment periods and reduction of principal and/or accrued interest.

There were no finance receivables modified as TDRs during the three months ended March 31, 2016 or 2015 for the Dealer portfolio segment. Finance receivables in the Customer portfolio segment modified as TDRs during the three months ended March 31, 2016 and 2015, were as follows:

	Three Months Ended March 31, 2016			Three Months Ended March 31, 2015		
(Millions of dollars)	Number of Contracts	Pre-TDR Recorded Investment	Post-TDR Recorded Investment	Number of Contracts	Pre-TDR Recorded Investment	Post-TDR Recorded Investment
North America	11	$ 10	$ 10	3	$ 1	$ 1
Asia Pacific	4	3	3	—	—	—
Latin America	2	—	—	—	—	—
Caterpillar Power Finance	4	39	27	2	83	80
Total [1]	21	$ 52	$ 40	5	$ 84	$ 81

TDRs in the Customer portfolio segment with a payment default during the three months ended March 31, 2016 and 2015, which had been modified within twelve months prior to the default date, were as follows:

	Three Months Ended March 31, 2016		Three Months Ended March 31, 2015	
(Millions of dollars)	Number of Contracts	Post-TDR Recorded Investment	Number of Contracts	Post-TDR Recorded Investment
North America	4	$ —	4	$ 1
Europe	13	1	—	—
Asia Pacific	3	—	—	—
Latin America	1	—	1	—
Total	21	$ 1	5	$ 1

17. Fair value disclosures

A. Fair value measurements

The guidance on fair value measurements defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants. This guidance also specifies a fair value hierarchy based upon the observability of inputs used in valuation techniques. Observable inputs (highest level) reflect market data obtained from independent sources, while unobservable inputs (lowest level) reflect internally developed market assumptions. In accordance with this guidance, fair value measurements are classified under the following hierarchy:

- Level 1 – Quoted prices for identical instruments in active markets.
- Level 2 – Quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations in which all significant inputs or significant value-drivers are observable in active markets.
- Level 3 – Model-derived valuations in which one or more significant inputs or significant value-drivers are unobservable.

When available, we use quoted market prices to determine fair value, and we classify such measurements within Level 1. In some cases where market prices are not available, we make use of observable market based inputs to calculate fair value, in which case the measurements are classified within Level 2. If quoted or observable market prices are not available, fair value is based upon valuations in which one or more significant inputs are unobservable, including internally developed models that use, where possible, current market-based parameters such as interest rates, yield curves and currency rates. These measurements are classified within Level 3.

Fair value measurements are classified according to the lowest level input or value-driver that is significant to the valuation. A measurement may therefore be classified within Level 3 even though there may be significant inputs that are readily observable.

Fair value measurement includes the consideration of nonperformance risk. Nonperformance risk refers to the risk that an obligation (either by a counterparty or Caterpillar) will not be fulfilled. For financial assets traded in an active market (Level 1 and certain Level 2), the nonperformance risk is included in the market price. For certain other financial assets and liabilities (certain Level 2 and Level 3), our fair value calculations have been adjusted accordingly.

Investments in debt and equity securities
Investments in certain debt and equity securities, primarily at Insurance Services, have been classified as available-for-sale and recorded at fair value. Fair values for our U.S. treasury bonds and large capitalization value and smaller company growth equity securities are based upon valuations for identical instruments in active markets. Fair values for other government bonds, corporate bonds and mortgage-backed debt securities are based upon models that take into consideration such market-based factors as recent sales, risk-free yield curves and prices of similarly rated bonds.

In addition, Insurance Services has an equity investment in a real estate investment trust (REIT) which is recorded at fair value based on the net asset value (NAV) of the investment.

See Note 8 for additional information on our investments in debt and equity securities.

Derivative financial instruments
The fair value of interest rate swap derivatives is primarily based on models that utilize the appropriate market-based forward swap curves and zero-coupon interest rates to determine discounted cash flows. The fair value of foreign currency and commodity forward, option and cross currency contracts is based on a valuation model that discounts cash flows resulting from the differential between the contract price and the market-based forward rate.

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Assets and liabilities measured on a recurring basis at fair value, primarily related to Financial Products, included in our Consolidated Statement of Financial Position as of March 31, 2016 and December 31, 2015 are summarized below:

	March 31, 2016			
(Millions of dollars)	Level 1	Level 2	Level 3	Total Assets / Liabilities, at Fair Value
Assets				
Available-for-sale securities				
Government debt				
U.S. treasury bonds	$12	$—	$ —	$ 12
Other U.S. and non-U.S. government bonds	—	72	—	72
Corporate bonds				
Corporate bonds	—	720	—	720
Asset-backed securities	—	127	—	127
Mortgage-backed debt securities				
U.S. governmental agency	—	288	—	288
Residential	—	11	—	11
Commercial	—	60	—	60
Equity securities				
Large capitalization value	277	—	—	277
Smaller company growth	52	—	—	52
Total available-for-sale securities	341	1,278	—	1,619
REIT	—	—	51	51
Derivative financial instruments, net	—	111	—	111
Total Assets	$341	$1,389	$ 51	$ 1,781

	December 31, 2015			
(Millions of dollars)	Level 1	Level 2	Level 3	Total Assets / Liabilities, at Fair Value
Assets				
Available-for-sale securities				
Government debt				
U.S. treasury bonds	$9	$—	$ —	$ 9
Other U.S. and non-U.S. government bonds	—	72	—	72
Corporate bonds				
Corporate bonds	—	708	—	708
Asset-backed securities	—	129	—	129
Mortgage-backed debt securities				
U.S. governmental agency	—	292	—	292
Residential	—	12	—	12
Commercial	—	61	—	61
Equity securities				
Large capitalization value	273	—	—	273
Smaller company growth	54	—	—	54
Total available-for-sale securities	336	1,274	—	1,610

REIT	—	—	25	25
Derivative financial instruments, net	—	49	—	49
Total Assets	$336	$1,323	$ 25	$ 1,684

The fair value of our REIT investment is measured based on NAV, which is considered a Level 3 input. A roll-forward for the three months ended March 31, 2016 of our REIT investment, which was purchased during the fourth quarter of 2015, is as follows.

(Millions of dollars)	REIT
Balance at December 31, 2015	$ 25
Purchases of securities	25
Sale of securities	—
Gains (losses) included in Accumulated other comprehensive income (loss)	1
Balance at March 31, 2016	$ 51

In addition to the amounts above, Cat Financial impaired loans are subject to measurement at fair value on a nonrecurring basis and are classified as Level 3 measurements. A loan is considered impaired when management determines that collection of contractual amounts due is not probable. In these cases, an allowance for credit losses may be established based either on the present value of expected future cash flows discounted at the receivables' effective interest rate, or the fair value of the collateral for collateral-dependent receivables. In determining collateral value, Cat Financial estimates the current fair market value of the collateral less selling costs. Cat Financial had impaired loans with a fair value of $69 million and $91 million as of March 31, 2016 and December 31, 2015, respectively.

B. Fair values of financial instruments

In addition to the methods and assumptions we use to record the fair value of financial instruments as discussed in the Fair value measurements section above, we used the following methods and assumptions to estimate the fair value of our financial instruments:

Cash and short-term investments
Carrying amount approximated fair value.

Restricted cash and short-term investments
Carrying amount approximated fair value. Restricted cash and short-term investments are included in Prepaid expenses and other current assets in the Consolidated Statement of Financial Position.

Finance receivables
Fair value was estimated by discounting the future cash flows using current rates, representative of receivables with similar remaining maturities.

Wholesale inventory receivables
Fair value was estimated by discounting the future cash flows using current rates, representative of receivables with similar remaining maturities.

Short-term borrowings
Carrying amount approximated fair value.

Long-term debt
Fair value for fixed and floating rate debt was estimated based on quoted market prices.

Guarantees
The fair value of guarantees is based upon our estimate of the premium a market participant would require to issue the same guarantee in a stand-alone arms-length transaction with an unrelated party. If quoted or observable market prices are not available, fair value is based upon internally developed models that utilize current market-based assumptions.

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Please refer to the table below for the fair values of our financial instruments.

(Millions of dollars)	Fair Value of Financial Instruments March 31, 2016 Carrying Amount	Fair Value	December 31, 2015 Carrying Amount	Fair Value	Fair Value Levels	Reference
Assets						
Cash and short-term investments	$5,886	$5,886	$6,460	$6,460	1	
Restricted cash and short-term investments	65	65	52	52	1	
Investments in debt and equity securities	1,670	1,670	1,635	1,635	1, 2 & 3	Note 8
Finance receivables – net (excluding finance leases[1])	16,753	16,826	16,515	16,551	3	Note 16
Wholesale inventory receivables – net (excluding finance leases [1])	1,704	1,669	1,821	1,775	3	Note 16
Foreign currency contracts – net	66	66	13	13	2	Note 4
Interest rate swaps – net	52	52	48	48	2	Note 4
Liabilities						
Short-term borrowings	7,817	7,817	6,967	6,967	1	
Long-term debt (including amounts due within one year)						
Machinery, Energy & Transportation	9,482	11,234	9,477	10,691	2	
Financial Products	21,064	21,596	21,569	21,904	2	
Commodity contracts – net	7	7	12	12	2	Note 4
Guarantees	12	12	12	12	3	Note 10

1 Total excluded items have a net carrying value at March 31, 2016 and December 31, 2015 of $6,409 million and $6,452 million, respectively.

18. Restructuring costs

Our accounting for employee separations is dependent upon how the particular program is designed. For voluntary programs, eligible separation costs are recognized at the time of employee acceptance unless the acceptance requires explicit approval by the company. For involuntary programs, eligible costs are recognized when management has approved the program, the affected employees have been properly notified and the costs are estimable.

For the three months ended March 31, 2016, we recognized $161 million of restructuring costs. The costs included $82 million of long-lived asset impairments, $31 million of employee separation costs and $11 million of other restructuring costs and were recognized in Other operating (income) expenses in the Consolidated Statement of Results of Operations. In addition, for the three months ended March 31, 2016, we incurred costs related to our restructuring programs of $37 million. These costs were primarily for accelerated depreciation and inventory write-downs and were recognized primarily in Cost of goods sold. The restructuring costs in 2016 were related to our decision to discontinue production of on-highway vocational trucks and other restructuring actions across the company, most of which were related to our September 2015 announcement regarding significant restructuring and cost reduction actions to lower our operating costs in response to weak economic and business conditions. For the three months ended March 31, 2015, we recognized $35 million of restructuring costs, which included $34 million of employee separation costs and $1 million of long-lived asset impairments. For the first three months of 2015, the restructuring costs were primarily related to facility closures and workforce reductions in Europe.

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Restructuring costs for the year ended December 31, 2015 were $898 million which included $641 million of employee separation costs, $127 million of long-lived asset impairments and $82 million of defined benefit retirement plan curtailment losses and were recognized in Other operating (income) expense. In addition, in 2015 we incurred costs related to our restructuring programs of $48 million. These costs were primarily for accelerated depreciation and inventory write-downs and were recognized primarily in Cost of goods sold. The restructuring costs in 2015 were related to several restructuring programs across the company.

Restructuring costs are a reconciling item between Segment profit and Consolidated profit before taxes. See Note 15 for more information.

The following table summarizes the 2015 and 2016 employee separation activity:

(Millions of dollars)	Total
Liability balance at December 31, 2014	$ 182
Increase in liability (separation charges)	641
Reduction in liability (payments)	(340)
Liability balance at December 31, 2015	$ 483
Increase in liability (separation charges)	31
Reduction in liability (payments)	(405)
Liability balance at March 31, 2016	$ 109

As part of our September 2015 announcement, we offered a voluntary retirement enhancement program to qualifying U.S. employees, various voluntary separation programs outside of the U.S. and implemented additional involuntary separation programs throughout the company. We have eliminated approximately 5,300 positions since then. As of December 31, 2015, we incurred $379 million of employee separation costs and $82 million of defined benefit retirement plan curtailment losses related to these programs. Additionally, we incurred $31 million of employee separation costs in the first quarter of 2016. Substantially all of the employee separation costs included in the December 31, 2015 liability balance were paid in the first quarter of 2016. Most of the March 31, 2016 liability balance is expected to be paid in 2016.

In February 2016, we made the decision to discontinue production of on-highway vocational trucks. Based on the current business climate in the truck industry and a thorough evaluation of the business, the company decided it would withdraw from this market. We estimate restructuring costs incurred under the restructuring plan to be $120 million. For the three months ended March 31, 2016, we recognized $74 million of restructuring costs primarily for long-lived asset impairments related to this restructuring plan. The remaining costs are expected to be recognized in 2016.

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

Overview

First-quarter 2016 sales and revenues were $9.461 billion, a 26 percent decrease from first-quarter 2015 sales and revenues of $12.702 billion. Sales declined across the company with substantial reductions in construction, oil and gas, mining and rail reflecting continued weak conditions in many of the industries we serve. Profit per share for the first quarter of 2016 was $0.46, a 77 percent decrease from first-quarter 2015 profit per share of $2.03. Profit was $271 million in the first quarter of 2016, a decrease of 78 percent from $1.245 billion in the first quarter of 2015. Profit declined primarily due to lower sales volume.

Highlights for the first quarter of 2016 include:

- First-quarter sales and revenues were $9.461 billion, compared with $12.702 billion in the first quarter of 2015. Sales decreased in Energy & Transportation, Construction Industries and Resource Industries. Financial Products' revenues also decreased.

- Restructuring costs were $161 million in the first quarter of 2016 with an after-tax impact of $0.21 per share, compared with restructuring costs of $35 million in the first quarter of 2015 with an after-tax impact of $0.04 per share.

- Profit per share was $0.46 in the first quarter of 2016 and excluding restructuring costs of $0.21 per share was $0.67 per share. Profit in the first quarter of 2015 was $2.03 per share and excluding restructuring costs of $0.04 per share was $2.07 per share.

- Machinery, Energy & Transportation (ME&T) operating cash flow was $218 million in the first quarter of 2016, compared to $1.042 billion in the first quarter of 2015.

- ME&T debt-to-capital ratio was 37.7 percent at March 31, 2016 compared to 39.0 percent at the end of 2015.

Restructuring Costs

In the first quarter of 2016, we continued our focus on structural cost reduction to help improve our long-term results. Restructuring costs of $161 million were related to our decision to discontinue production of on-highway vocational trucks and other restructuring actions across the company. For 2016, we anticipate these restructuring actions will result in costs of about $550 million.

Notes:

- Effective January 1, 2016, we made several changes that impacted the accounting for pension and other post-employment benefits. See Retirement Benefits discussion on page 66. We also made changes to organizational accountabilities and internal reporting that impacted segment results. Our 2015 financial information has been recast to be consistent with the 2016 presentation.
- Glossary of terms is included on pages 58-60; first occurrence of terms shown in bold italics.
- Information on non-GAAP financial measures is included on page 67.

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Consolidated Results of Operations

THREE MONTHS ENDED MARCH 31, 2016 COMPARED WITH THREE MONTHS ENDED MARCH 31, 2015

CONSOLIDATED SALES AND REVENUES

The chart above graphically illustrates reasons for the change in Consolidated Sales and Revenues between the first quarter of 2015 (at left) and the first quarter of 2016 (at right). Items favorably impacting sales and revenues appear as upward stair steps with the corresponding dollar amounts above each bar, while items negatively impacting sales and revenues appear as downward stair steps with dollar amounts reflected in parentheses above each bar. Caterpillar management utilizes these charts internally to visually communicate with the company's Board of Directors and employees.

Sales and Revenues

Total sales and revenues were $9.461 billion in the first quarter of 2016, compared with $12.702 billion in the first quarter of 2015, a decline of $3.241 billion, or 26 percent. The decrease was primarily due to lower sales volume. While sales for both new equipment and aftermarket parts declined in all segments, most of the decrease was for new equipment. The unfavorable impact of price realization and currency also contributed to the decline. We expect the relative strength of the U.S. dollar will negatively impact sales in 2016.

Dealer machine and engine inventories increased about $300 million in the first quarter of 2016 and about $900 million in the first quarter of 2015. For the full year of 2016, we expect dealers will continue to reduce inventories. Dealers are independent, and there could be many reasons for changes in their inventory levels. In general, dealers adjust inventory based on their expectations of future demand and product delivery times. Dealers' demand expectations take into account seasonal changes, macroeconomic conditions and other factors. Delivery times can vary based on availability of product from Caterpillar factories and product distribution centers.

Sales declined in all regions. In North America, sales decreased 26 percent due to both lower end-user demand, primarily in Energy & Transportation, and the unfavorable impact of changes in dealer inventories, primarily in Construction Industries. In EAME, sales declined 24 percent, primarily in Africa/Middle East due to weak economic conditions resulting from low oil and other commodity prices. Asia/Pacific sales declined 23 percent, primarily due to lower end-user demand for Energy & Transportation applications and products used in mining. Sales decreased 43 percent in Latin America, primarily due to widespread economic weakness across the region. The most significant decreases were in Brazil and Mexico.

Sales decreased in all segments. Energy & Transportation's sales declined 33 percent largely due to lower end-user demand for oil and gas and transportation applications. Construction Industries' sales decreased 19 percent, primarily due to the unfavorable impact of changes in dealer inventories, lower demand from end users and unfavorable price realization. Resource Industries' sales declined 26 percent, mostly due to continued low end-user demand. Financial Products' segment revenues were down 7 percent, primarily due to lower average earning assets and lower average financing rates.

CONSOLIDATED OPERATING PROFIT

The chart above graphically illustrates reasons for the change in Consolidated Operating Profit between the first quarter of 2015 (at left) and the first quarter of 2016 (at right). Items favorably impacting operating profit appear as upward stair steps with the corresponding dollar amounts above each bar, while items negatively impacting operating profit appear as downward stair steps with dollar amounts reflected in parentheses above each bar. Caterpillar management utilizes these charts internally to visually communicate with the company's Board of Directors and employees. The bar entitled Other includes consolidating adjustments and Machinery, Energy & Transportation other operating (income) expenses.

Operating profit for the first quarter of 2016 was $494 million, compared with $1.702 billion in the first quarter of 2015. The decrease of $1.208 billion was primarily due to lower sales volume, including an unfavorable mix of products, resulting from continued weak commodity prices globally and economic weakness in developing countries. In addition, price realization and restructuring costs were unfavorable. These items were partially offset by favorable period costs and variable manufacturing costs.

The unfavorable price realization resulted from competitive market conditions and an unfavorable geographic mix of sales. We continue to see competitive pressure that started in the last half of 2015 driven by excess industry capacity, unfavorable currency pressure, as the impact of the stronger dollar benefited competitors based outside the United States, and an overall weak economic environment. We expect the current competitive pressure to continue for the remainder of the year, particularly in Construction Industries and Resource Industries. However, we expect that most of the year-over-year weakness will occur in the first half of 2016, as price realization was more negative in the second half of 2015 compared to the first half.

Variable manufacturing costs were favorable, primarily due to improved material costs. Period costs were lower, primarily resulting from substantial restructuring and cost reduction actions and lower short-term incentive compensation expense. The reductions impacted period manufacturing costs and selling, general and administrative expenses (SG&A). Research and development expenses (R&D) were about flat.

Restructuring costs of $161 million in the first quarter of 2016 were related to our decision to discontinue production of on-highway vocational trucks and other restructuring actions across the company. In the first quarter of 2015, restructuring costs were $35 million.

Short-term incentive compensation expense is directly related to financial and operational performance, measured against targets set annually. First-quarter 2016 expense was about $120 million. First-quarter 2015 expense was about $215 million.

Other Profit/Loss Items

Other income/expense in the first quarter of 2016 was zero, compared with income of $194 million in the first quarter of 2015. The unfavorable change was primarily due to the absence of a gain of $120 million on the sale of the remaining 35 percent interest in our former third-party logistics business. In addition, the net impact from currency translation and hedging gains and losses was unfavorable. There were net losses in the first quarter of 2016, compared to net gains in the first quarter of 2015.

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The provision for income taxes in the first quarter reflects an estimated annual tax rate of 25 percent, compared to 29.5 percent for the first quarter of 2015 and 25.5 percent for the full-year 2015 excluding a $42 million discrete tax charge. The full-year rate for 2015 of 25.5 percent was lower than the first-quarter 2015 rate, primarily due to changes in the geographic mix of profits from a tax perspective along with the impact of the permanent renewal of the U.S. research and development tax credit in the fourth quarter.

Segment Information

Sales and Revenues by Geographic Region

(Millions of dollars)	Total	% Change	North America	% Change	Latin America	% Change	EAME	% Change	Asia/ Pacific	% Change
First Quarter 2016										
Construction Industries [1]	$4,043	(19)%	$2,058	(18)%	$231	(52)%	$847	(17)%	$907	(9)%
Resource Industries [2]	1,449	(26)%	604	(23)%	268	(14)%	262	(43)%	315	(23)%
Energy & Transportation [3]	3,278	(33)%	1,566	(34)%	200	(53)%	982	(21)%	530	(40)%
All Other Segments [4]	38	(47)%	15	(42)%	1	(75)%	9	(63)%	13	(28)%
Corporate Items and Eliminations	(28)	—	(24)		(1)		(2)		(1)	
Machinery, Energy & Transportation Sales	8,780	(27)%	4,219	(26)%	699	(43)%	2,098	(24)%	1,764	(23)%
Financial Products Segment	743	(7)%	459	2 %	87	(19)%	98	(10)%	99	(23)%
Corporate Items and Eliminations	(62)		(34)		(14)		(4)		(10)	
Financial Products Revenues	681	(8)%	425	— %	73	(25)%	94	(10)%	89	(24)%
Consolidated Sales and Revenues	$9,461	(26)%	$4,644	(24)%	$772	(41)%	$2,192	(23)%	$1,853	(23)%
First Quarter 2015										
Construction Industries [1]	$5,014		$2,520		$480		$1,017		$997	
Resource Industries [2]	1,971		789		311		462		409	
Energy & Transportation [3]	4,915		2,368		425		1,244		878	
All Other Segments [4]	72		26		4		24		18	
Corporate Items and Eliminations	(11)		(16)		1		1		3	
Machinery, Energy & Transportation Sales	11,961		5,687		1,221		2,748		2,305	
Financial Products Segment	795		451		107		109		128	
Corporate Items and Eliminations	(54)		(28)		(10)		(5)		(11)	
Financial Products Revenues	741		423		97		104		117	

Consolidated Sales and Revenues	$12,702	$6,110	$1,318	$2,852	$2,422

[1] Does not include inter-segment sales of $8 million and $23 million in first quarter 2016 and 2015, respectively.
[2] Does not include inter-segment sales of $71 million and $87 million in first quarter 2016 and 2015, respectively.
[3] Does not include inter-segment sales of $632 million and $794 million in first quarter 2016 and 2015, respectively.
[4] Does not include inter-segment sales of $92 million and $103 million in first quarter 2016 and 2015, respectively.

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Sales and Revenues by Segment

(Millions of dollars)	First Quarter 2015	Sales Volume	Price Realization	Currency	Other	First Quarter 2016	$ Change	% Change
Construction Industries	$5,014	$(701)	$ (172)	$ (98)	$—	$4,043	$(971)	(19)%
Resource Industries	1,971	(463)	(38)	(21)	—	1,449	(522)	(26)%
Energy & Transportation	4,915	(1,543)	(24)	(70)	—	3,278	(1,637)	(33)%
All Other Segments	72	(33)	—	(1)	—	38	(34)	(47)%
Corporate Items and Eliminations	(11)	(19)	—	2	—	(28)	(17)	
Machinery, Energy & Transportation Sales	11,961	(2,759)	(234)	(188)	—	8,780	(3,181)	(27)%
Financial Products Segment	795	—	—	—	(52)	743	(52)	(7)%
Corporate Items and Eliminations	(54)	—	—	—	(8)	(62)	(8)	
Financial Products Revenues	741	—	—	—	(60)	681	(60)	(8)%
Consolidated Sales and Revenues	$12,702	$(2,759)	$ (234)	$ (188)	$(60)	$9,461	$(3,241)	(26)%

Operating Profit / (Loss) by Segment

(Millions of dollars)	First Quarter 2016	First Quarter 2015	$ Change	% Change
Construction Industries	$ 440	$745	$(305)	(41)%
Resource Industries	(96)	96	(192)	(200)%
Energy & Transportation	410	1,024	(614)	(60)%
All Other Segments	(7)	(7)	—	—%
Corporate Items and Eliminations	(357)	(319)	(38)	
Machinery, Energy & Transportation	390	1,539	(1,149)	(75)%
Financial Products Segment	168	227	(59)	(26)%
Corporate Items and Eliminations	(1)	3	(4)	
Financial Products	167	230	(63)	(27)%
Consolidating Adjustments	(63)	(67)	4	
Consolidated Operating Profit / (Loss)	$ 494	$1,702	$(1,208)	(71)%

Construction Industries

Construction Industries’ sales were $4.043 billion in the first quarter of 2016, a decrease of $971 million, or 19 percent, from the first quarter of 2015. The decrease in sales was due to lower volume, unfavorable price realization and the unfavorable impact of currency. While sales declined for both new equipment and aftermarket parts, substantially all of the decrease was for new equipment.

About half of the sales volume decline was due to the unfavorable impact of changes in dealer inventories. Dealers increased inventories in both the first quarter of 2016 and the first quarter of 2015; however, the increase was greater in the first quarter of 2015. In addition, deliveries to end users were lower.

Price realization was unfavorable $172 million due to competitive market conditions including the impact of the stronger dollar, which benefited competitors based outside the United States.

The unfavorable impact of currency was due to the strengthening of the U.S. dollar compared to most other currencies.

Sales decreased in all regions.

In North America, the sales decline was primarily due to dealers increasing inventories more significantly in the first quarter of 2015 than the first quarter of 2016. In addition, although residential and nonresidential construction activity is improving, sales to end users were lower than the first quarter of 2015. We believe declines in construction activity related to oil and gas have resulted in the availability of existing construction equipment for other purposes. We expect this trend will continue to negatively impact our sales volume in 2016. Unfavorable price realization resulted from competitive market conditions.

In Latin America, end-user demand was down across the region, with the most significant declines in Brazil due to depressed economic conditions and in Mexico due to weak construction activity.

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Lower sales in EAME were primarily due to unfavorable price realization and lower end-user demand. Price realization was unfavorable across the region due to competitive market conditions. The decline in end-user demand was most significant in oil-producing economies that depend on oil revenues to fund expenditures for roads and other infrastructure projects. In addition, sales declined in South Africa where we believe an uncertain regulatory and political environment contributed to lower end-user demand.

Sales in Asia/Pacific were down as a result of the unfavorable impact of changes in dealer inventories, which were about flat in the first quarter of 2016 and increased in the first quarter of 2015. Deliveries to end users were up slightly, primarily in China. It is unclear whether this is a trend that will continue.

Construction Industries' profit was $440 million in the first quarter of 2016, compared with $745 million in the first quarter of 2015. The decrease in profit was primarily due to lower sales volume, including an unfavorable mix of products and unfavorable price realization resulting from competitive market conditions. The decline was partially offset by favorable costs, primarily due to restructuring and cost reduction actions and lower material costs.

Resource Industries

Resource Industries' sales were $1.449 billion in the first quarter of 2016, a decrease of $522 million, or 26 percent, from the first quarter of 2015. The decline was primarily due to lower sales volume. Sales were lower for both new equipment and aftermarket parts.

The sales decrease was primarily due to lower end-user demand across all regions. In addition, the sales decline in EAME was partially due to the unfavorable impact of changes in dealer inventories, as dealers lowered inventories in the first quarter of 2016, compared to increasing inventories in the first quarter of 2015.

Commodity prices improved from their recent lows, but excess supply remains. It is not clear at this time that the current prices are either sustainable or sufficient to drive increased demand for equipment. Difficult financial conditions for many mining customers around the world persist. Mining customers continued to focus on improving productivity in existing mines and reducing their total capital expenditures, as they have for several years. As a result, sales and new orders in Resource Industries continue to be weak.

Resource Industries incurred a loss of $96 million in the first quarter of 2016, compared with profit of $96 million in the first quarter of 2015. The unfavorable change was due to lower sales volume and negative price realization. This was partially offset by improved period manufacturing and SG&A expenses due to restructuring and cost reduction actions.

Energy & Transportation

Energy & Transportation's sales were $3.278 billion in the first quarter of 2016, a decrease of $1.637 billion, or 33 percent, from the first quarter of 2015. The decrease was primarily the result of lower sales volume. Sales decreased in all applications with more than 80 percent of the decline in oil and gas and transportation.

Oil and Gas - Sales continued to decrease in much of the world due to low oil prices. Although oil prices were low in the first quarter of 2015, our sales benefited from a strong order backlog. The sales decline was most significant in equipment used for gas compression, well servicing and production, with the most significant impact in North America. The decline in sales of equipment for gas compression was primarily in reciprocating engines.

While oil prices have improved since the beginning of 2016, it is not clear at this time that the current price level is either sustainable or sufficient to drive increased demand for equipment. We monitor a number of factors in addition to oil prices that shape our expectations, including recent order rates, quotation activity, our current backlog, trends in retail statistics and discussions with our customers. Based on all of these factors, we do not see the current oil price driving a turnaround in demand for our products in 2016.

Transportation - Sales decreased in all geographic regions. The most significant decline was in North America, primarily due to significant weakness in the rail industry. We believe our sales into the rail industry are being negatively impacted by significantly lower carload volumes. In addition, the first quarter of 2015 benefited from deliveries of locomotives that began production in 2014. In Asia/Pacific, the decrease was due to the absence of a large locomotive sale in the first quarter of 2015 and a decline for equipment used in marine applications.

Power Generation - Sales decreased significantly in Latin America and North America, slightly in EAME and were about flat in Asia/Pacific. The decline is primarily due to weak economic conditions in Latin America and the absence of several large projects in North America.

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Industrial - Sales were lower in Asia/Pacific, Latin America and North America and about flat in EAME. The decline in sales was primarily due to lower end-user demand for most industrial applications.

Energy & Transportation’s profit was $410 million in the first quarter of 2016, compared with $1.024 billion in the first quarter of 2015. The decline was due to a decrease in sales volume, partially offset by lower costs primarily due to restructuring and cost reduction actions and favorable material costs.

Financial Products Segment

Financial Products’ revenues were $743 million in the first quarter of 2016, a decrease of $52 million, or 7 percent, from the first quarter of 2015. The decline was primarily due to lower average earning assets and lower average financing rates. Average earning assets were down in Asia/Pacific, Latin America and EAME, partially offset by higher average earning assets in North America. Average financing rates decreased across all regions.

Financial Products’ profit was $168 million in the first quarter of 2016, compared with $227 million in the first quarter of 2015. The decrease was primarily due to a $17 million decrease in net yield on average earning assets reflecting geographic mix changes and currency impacts, an $11 million increase in the provision for credit losses at Cat Financial and a $10 million unfavorable impact from lower average earning assets.

At the end of the first quarter of 2016, past dues at Cat Financial were 2.78 percent, compared with 3.08 percent at the end of the first quarter of 2015 and 2.14 percent at the end of 2015. There is some seasonality in past due percentages and it is common to see an increase in the first quarter. Write-offs, net of recoveries, were $31 million for the first quarter of 2016, compared with $12 million for the first quarter of 2015. The increase in write-offs, net of recoveries, was primarily driven by the Caterpillar Power Finance and North American portfolios.

As of March 31, 2016, Cat Financial's allowance for credit losses totaled $340 million, or 1.21 percent of net finance receivables, compared with $392 million, or 1.38 percent of net finance receivables at March 31, 2015. The allowance for credit losses at year-end 2015 was $338 million, or 1.22 percent of net finance receivables.

Corporate Items and Eliminations

Expense for corporate items and eliminations was $358 million in the first quarter of 2016, an increase of $42 million from the first quarter of 2015. Corporate items and eliminations include: corporate-level expenses; restructuring costs; timing differences, as some expenses are reported in segment profit on a cash basis; retirement benefit costs other than service cost; currency differences for ME&T, as segment profit is reported using annual fixed exchange rates; cost of sales methodology differences as segments use a current cost methodology; and inter-segment eliminations.

The increase in expense from the first quarter of 2015 was primarily due to a $126 million increase in restructuring costs, partially offset by lower stock-based compensation expense and methodology differences.

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RESTRUCTURING COSTS

For the three months ended March 31, 2016, we recognized $161 million of restructuring costs. The costs included $82 million of long-lived asset impairments, $31 million of employee separation costs and $11 million of other restructuring costs and were recognized in Other operating (income) expenses in the Consolidated Statement of Results of Operations. In addition, for the three months ended March 31, 2016, we incurred costs related to our restructuring programs of $37 million. These costs were primarily for accelerated depreciation and inventory write-downs and were recognized primarily in Cost of goods sold. The restructuring costs in 2016 were related to our decision to discontinue production of on-highway vocational trucks and other restructuring actions across the company, most of which were related to our September 2015 announcement regarding significant restructuring and cost reduction actions to lower our operating costs in response to weak economic and business conditions. For the three months ended March 31, 2015, we recognized $35 million of restructuring costs, which included $34 million of employee separation costs and $1 million of long-lived asset impairments. For the first three months of 2015, the restructuring costs were primarily related to facility closures and workforce reduction in Europe.

Restructuring costs for the year ended December 31, 2015 were $898 million which included $641 million of employee separation costs, $127 million of long-lived asset impairments and $82 million of defined benefit retirement plan curtailment losses and were recognized in Other operating (income) expense. In addition, in 2015 we incurred costs related to our restructuring programs of $48 million. These costs were primarily for accelerated depreciation and inventory write-downs and were recognized primarily in Cost of goods sold. The restructuring costs in 2015 were related to several restructuring programs across the company.

Restructuring costs are a reconciling item between Segment profit and Consolidated profit before taxes.

The following table summarizes the 2015 and 2016 employee separation activity:

(Millions of dollars)	Total
Liability balance at December 31, 2014	$ 182
Increase in liability (separation charges)	641
Reduction in liability (payments)	(340)
Liability balance at December 31, 2015	$ 483
Increase in liability (separation charges)	31
Reduction in liability (payments)	(405)
Liability balance at March 31, 2016	$ 109

As part of our September 2015 announcement, we offered a voluntary retirement enhancement program to qualifying U.S. employees, various voluntary separation programs outside of the U.S. and implemented additional involuntary separation programs throughout the company. We have eliminated approximately 5,300 positions since then. As of December 31, 2015, we incurred $379 million of employee separation costs and $82 million of defined benefit retirement plan curtailment losses related to these programs. Additionally, we incurred $31 million of employee separation costs in the first quarter of 2016. Substantially all of the employee separation costs included in the

December 31, 2015 liability balance were paid in the first quarter of 2016. Most of the March 31, 2016 liability balance is expected to be paid in 2016.

In February 2016, we made the decision to discontinue production of on-highway vocational trucks. Based on the current business climate in the truck industry and a thorough evaluation of the business, the company decided it would withdraw form this market. We estimate restructuring costs incurred under the restructuring plan to be $120 million. For the three months ended March 31, 2016, we recognized $74 million of restructuring costs primarily for long-lived asset impairments related to this restructuring plan. The remaining costs are expected to be recognized in 2016.

Additional restructuring actions are being contemplated including the consolidation and closures of manufacturing facilities occurring through 2018. For full-year 2016, we expect restructuring costs will be about $550 million. We expect that restructuring actions will result in a benefit to operating costs, primarily SG&A expenses and Cost of goods sold of about $700 million in 2016 compared with 2015.

GLOSSARY OF TERMS

1. All Other Segments - Primarily includes activities such as: the business strategy, product management, development, and manufacturing of filters and fluids, undercarriage, tires and rims, ground engaging tools, fluid transfer products, precision seals and rubber, and sealing and connecting components primarily for Cat products; parts distribution; distribution services

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responsible for dealer development and administration including a wholly owned dealer in Japan, dealer portfolio management and ensuring the most efficient and effective distribution of machines, engines and parts; digital investments for new customer and dealer solutions that integrate data analytics with state-of-the art digital technologies while transforming the buying experience.

2. Consolidating Adjustments - Elimination of transactions between Machinery, Energy & Transportation and Financial Products.
3. Construction Industries - A segment primarily responsible for supporting customers using machinery in infrastructure, forestry and building construction applications. Responsibilities include business strategy, product design, product management and development, manufacturing, marketing and sales and product support. The product portfolio includes backhoe loaders, small wheel loaders, small track-type tractors, skid steer loaders, multi-terrain loaders, mini excavators, compact wheel loaders, telehandlers, select work tools, small, medium and large track excavators, wheel excavators, medium wheel loaders, compact track loaders, medium track-type tractors, track-type loaders, motor graders, pipelayers, forestry and paving products.
4. Currency - With respect to sales and revenues, currency represents the translation impact on sales resulting from changes in foreign currency exchange rates versus the U.S. dollar. With respect to operating profit, currency represents the net translation impact on sales and operating costs resulting from changes in foreign currency exchange rates versus the U.S. dollar. Currency includes the impact on sales and operating profit for the Machinery, Energy & Transportation lines of business only; currency impacts on Financial Products' revenues and operating profit are included in the Financial Products' portions of the respective analyses. With respect to other income/expense, currency represents the effects of forward and option contracts entered into by the company to reduce the risk of fluctuations in exchange rates (hedging) and the net effect of changes in foreign currency exchange rates on our foreign currency assets and liabilities for consolidated results (translation).
5. Debt-to-Capital Ratio - A key measure of Machinery, Energy & Transportation's financial strength used by management. The metric is defined as Machinery, Energy & Transportation's short-term borrowings, long-term debt due within one year and long-term debt due after one year (debt) divided by the sum of Machinery, Energy & Transportation's debt and stockholders' equity. Debt also includes Machinery, Energy & Transportation's long-term borrowings from Financial Products.
6. EAME - A geographic region including Europe, Africa, the Middle East and the Commonwealth of Independent States (CIS).
7. Earning Assets - Assets consisting primarily of total finance receivables net of unearned income, plus equipment on operating leases, less accumulated depreciation at Cat Financial.
8. Energy & Transportation - A segment primarily responsible for supporting customers using reciprocating engines, turbines, diesel-electric locomotives and related parts across industries serving power generation, industrial, oil and gas and transportation applications, including marine and rail-related businesses. Responsibilities include business strategy, product design, product management and development, manufacturing, marketing and sales and product support of turbines and turbine-related services, reciprocating engine powered generator sets, integrated systems used in the electric power generation industry, reciprocating engines and integrated systems and solutions for the marine and oil and gas industries; reciprocating engines supplied to the industrial industry as well as Cat machinery; the remanufacturing of Cat® engines and components and remanufacturing services for other companies; the business strategy, product design, product management and development, manufacturing, remanufacturing, leasing and service of diesel-electric locomotives and components and other rail-related products and services and product support of on-highway vocational trucks for North America.
9. Financial Products Segment - Provides financing to customers and dealers for the purchase and lease of Cat and other equipment, as well as some financing for Caterpillar sales to dealers. Financing plans include operating and finance leases, installment sale contracts, working capital loans and wholesale financing plans. The segment also provides various forms of insurance to customers and dealers to help support the purchase and lease of our equipment. Financial Products Segment profit is determined on a pretax basis and includes other income/expense items.
10. Latin America - A geographic region including Central and South American countries and Mexico.

11. Machinery, Energy & Transportation (ME&T) - Represents the aggregate total of Construction Industries, Resource Industries, Energy & Transportation and All Other Segments and related corporate items and eliminations.
12. Machinery, Energy & Transportation Other Operating (Income) Expenses - Comprised primarily of gains/losses on disposal of long-lived assets, gains/losses on divestitures and legal settlements and accruals. Restructuring costs classified as other operating expenses on the Results of Operations are presented separately on the Operating Profit Comparison.
13. Pension and other postemployment benefit (OPEB) costs - Costs for the company's defined benefit pension and postretirement benefit plans.

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14. Period Costs - Includes period manufacturing costs, selling, general and administrative (SG&A) and research and development (R&D) expenses excluding the impact of currency. Period manufacturing costs support production but are defined as generally not having a direct relationship to short-term changes in volume. Examples include machinery and equipment repair, depreciation on manufacturing assets, facility support, procurement, factory scheduling, manufacturing planning and operations management. SG&A and R&D costs are not linked to the production of goods or services and include marketing, legal and financial services and the development of new and significant improvements in products or processes.
15. Price Realization - The impact of net price changes excluding currency and new product introductions. Price realization includes geographic mix of sales, which is the impact of changes in the relative weighting of sales prices between geographic regions.
16. Resource Industries - A segment primarily responsible for supporting customers using machinery in mining, quarry, waste, and material handling applications. Responsibilities include business strategy, product design, product management and development, manufacturing, marketing and sales and product support. The product portfolio includes large track-type tractors, large mining trucks, hard rock vehicles, longwall miners, electric rope shovels, draglines, hydraulic shovels, track and rotary drills, highwall miners, large wheel loaders, off-highway trucks, articulated trucks, wheel tractor scrapers, wheel dozers, landfill compactors, soil compactors, material handlers, continuous miners, scoops and haulers, hardrock continuous mining systems, select work tools, machinery components and electronics and control systems. Resource Industries also manages areas that provide services to other parts of the company, including integrated manufacturing and research and development.
17. Restructuring Costs - Primarily costs for employee separation costs, long-lived asset impairments and contract terminations. These costs are included in Other Operating (Income) Expenses. Restructuring costs also include other exit-related costs primarily for accelerated depreciation and equipment relocation (primarily included in Cost of goods sold) and sales discounts and payments to dealers and customers related to discontinued products (included in Sales of ME&T).
18. Sales Volume - With respect to sales and revenues, sales volume represents the impact of changes in the quantities sold for Machinery, Energy & Transportation as well as the incremental revenue impact of new product introductions, including emissions-related product updates. With respect to operating profit, sales volume represents the impact of changes in the quantities sold for Machinery, Energy & Transportation combined with product mix as well as the net operating profit impact of new product introductions, including emissions-related product updates. Product mix represents the net operating profit impact of changes in the relative weighting of Machinery, Energy & Transportation sales with respect to total sales.
19. Variable Manufacturing Costs - Represents volume-adjusted costs excluding the impact of currency. Variable manufacturing costs are defined as having a direct relationship with the volume of production. This includes material costs, direct labor and other costs that vary directly with production volume such as freight, power to operate machines and supplies that are consumed in the manufacturing process.

LIQUIDITY AND CAPITAL RESOURCES

Sources of funds

We generate significant capital resources from operating activities, which are the primary source of funding for our Machinery, Energy & Transportation operations. Funding for these businesses is also available from commercial paper and long-term debt issuances. Financial Products' operations are funded primarily from commercial paper, term debt issuances and collections from the existing portfolio. Despite continued weaknesses in many of the industries we serve, we had positive operating cash flow in the first quarter of 2016 within both our Machinery, Energy & Transportation and Financial Products' operations. On a consolidated basis, we ended the first quarter of 2016 with $5.89 billion of cash, a decrease of $574 million from year-end 2015. We intend to maintain a strong cash and liquidity position. Our cash balances are held in numerous locations throughout the world with approximately $4.8 billion held by our non-U.S. subsidiaries. Amounts held by non-U.S. subsidiaries are available for general corporate

use. However, if all of the cash held by non-U.S. subsidiaries were repatriated to the United States, a portion would be subject to additional U.S. tax.
Consolidated operating cash flow for the first quarter of 2016 was $489 million, down from $1.27 billion for the same period last year. The decrease was primarily due to lower profit before tax within the Machinery, Energy & Transportation business as well as higher employee separation payments in the first quarter of 2016 versus the first quarter of 2015. These employee separation payments were primarily related to the voluntary retirement enhancement program offered in the United States and announced in September 2015. Partially offsetting these items were lower short-term incentive compensation payments in 2016 compared to the same period a year ago. See further discussion of operating cash flow under Machinery, Energy & Transportation and Financial Products.

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Total debt as of March 31, 2016 was $38.36 billion, an increase of $350 million from year-end 2015. Debt related to Financial Products increased $341 million, primarily due to weakening of the U.S. dollar during the first quarter of 2016. Debt related to Machinery, Energy & Transportation increased $9 million in the first quarter of 2016.
We have three global credit facilities with a syndicate of banks totaling $10.50 billion (Credit Facility) available in the aggregate to both Caterpillar and Cat Financial for general liquidity purposes. Based on management's allocation decision, which can be revised from time to time, the portion of the Credit Facility available to Machinery, Energy & Transportation as of March 31, 2016 was $2.75 billion. Our three Global Credit Facilities are:

- The 364-day facility of $3.15 billion (of which $0.82 billion is available to Machinery, Energy, & Transportation) expires in September 2016.
- The three-year facility, as amended and restated in September 2015, of $2.73 billion (of which $0.72 billion is available to Machinery, Energy & Transportation) now expires in September 2018.
- The five-year facility, as amended and restated in September 2015, of $4.62 billion (of which $1.21 billion is available to Machinery, Energy & Transportation) now expires in September 2020.

At March 31, 2016, Caterpillar's consolidated net worth was $15.71 billion, which was above the $9.00 billion required under the Credit Facility. The consolidated net worth is defined as the consolidated stockholders' equity including preferred stock but excluding the pension and other postretirement benefits balance within Accumulated other comprehensive income (loss).
At March 31, 2016, Cat Financial's covenant interest coverage ratio was 1.98 to 1. This is above the 1.15 to 1 minimum ratio calculated as (1) profit excluding income taxes, interest expense and net gain/(loss) from interest rate derivatives to (2) interest expense calculated at the end of each calendar quarter for the rolling four quarter period then most recently ended, required by the Credit Facility.
In addition, at March 31, 2016, Cat Financial's covenant leverage ratio was 7.70 to 1. This is below the maximum ratio of debt to net worth of 10 to 1, calculated (1) on a monthly basis as the average of the leverage ratios determined on the last day of each of the six preceding calendar months and (2) at each December 31, required by the Credit Facility.
In the event Caterpillar or Cat Financial does not meet one or more of their respective financial covenants under the Credit Facility in the future (and are unable to obtain a consent or waiver), the syndicate of banks may terminate the commitments allocated to the party that does not meet its covenants. Additionally, in such event, certain of Cat Financial's other lenders under other loan agreements where similar financial covenants or cross default provisions are applicable, may, at their election, choose to pursue remedies under those loan agreements, including accelerating the repayment of outstanding borrowings. At March 31, 2016, there were no borrowings under the Credit Facility.
Our total credit commitments and available credit as of March 31, 2016 were:

	March 31, 2016		
(Millions of dollars)	Consolidated	Machinery, Energy & Transportation	Financial Products
Credit lines available:			
Global credit facilities	$10,500	$ 2,750	$ 7,750
Other external	4,139	224	3,915
Total credit lines available	14,639	2,974	11,665
Less: Commercial paper outstanding	(6,619)	—	(6,619)
Less: Utilized credit	(1,592)	(13)	(1,579)
Available credit	$6,428	$ 2,961	$ 3,467

The other external consolidated credit lines with banks as of March 31, 2016 totaled $4.14 billion. These committed and uncommitted credit lines, which may be eligible for renewal at various future dates or have no specified expiration date, are used primarily by our subsidiaries for local funding requirements. Caterpillar or Cat Financial may guarantee subsidiary borrowings under these lines.
In the event that Caterpillar or Cat Financial, or any of their debt securities, experiences a credit rating downgrade, it would likely result in an increase in our borrowing costs and make access to certain credit markets more difficult. In

the event economic conditions deteriorate such that access to debt markets becomes unavailable, our Machinery, Energy & Transportation's operations would rely on cash flow from operations, use of existing cash balances, borrowings from Cat Financial and access to our Credit Facility. Our Financial Products' operations would rely on cash flow from its existing portfolio, existing cash balances, access to our Credit Facility and other credit line facilities of Cat Financial and potential borrowings from Caterpillar. In addition, we

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maintain a support agreement with Cat Financial, which requires Caterpillar to remain the sole owner of Cat Financial and may, under certain circumstances, require Caterpillar to make payments to Cat Financial should Cat Financial fail to maintain certain financial ratios.

Machinery, Energy & Transportation

Net cash provided by operating activities was $218 million in the first quarter of 2016, compared with $1.04 billion for the same period in 2015. The decrease was primarily due to lower profit before tax, driven by lower sales across the company, as well as higher employee separation payments in the first quarter of 2016 versus the first quarter of 2015. These employee separation payments were primarily related to the voluntary retirement enhancement program offered in the United States and announced in September 2015. Partially offsetting these items were lower short-term incentive compensation payments in 2016 compared to the same period a year ago.

Net cash used for investing activities in the first quarter of 2016 was $1.32 billion, compared with net cash used of $331 million in the first quarter of 2015. The increase was due to Machinery, Energy & Transportation's lending activity with Financial Products entities.

Net cash provided by financing activities during the first quarter of 2016 was $509 million, compared with net cash used of $786 million in the first quarter of 2015. The favorable change was primarily due to Machinery, Energy & Transportation's borrowings from Financial Products entities as well as the absence of common stock repurchases in the first quarter of 2016, as compared with the first quarter of 2015.

Our priorities for the use of cash are to maintain a strong financial position in support of our credit rating, provide capital to support growth, appropriately fund employee benefit plans, pay dividends and repurchase common stock.

Strong financial position – A key measure of Machinery, Energy & Transportation's financial strength used by management is Machinery, Energy & Transportation's debt-to-capital ratio. Debt-to-capital is defined as short-term borrowings, long-term debt due within one year and long-term debt due after one year (debt) divided by the sum of debt and stockholders' equity. Debt also includes Machinery, Energy & Transportation's long-term borrowings from Financial Products. The debt-to-capital ratio for Machinery, Energy & Transportation was 37.7 percent at March 31, 2016, within our target range of 30 to 45 percent. The Machinery, Energy & Transportation's debt-to-capital ratio was 39.0 percent at December 31, 2015. The decrease in the debt-to-capital ratio was due to an increase in equity related to favorable foreign currency translation adjustments as well as profit from the first quarter of 2016.

Capital to support growth – Capital expenditures were $379 million during the first quarter of 2016, compared to $477 million for the same period in 2015. We expect Machinery, Energy and Transportation's capital expenditures in 2016 to be lower than 2015.

Appropriately funded employee benefit plans – At January 1, 2016, we changed our accounting principle for pension and other postretirement plans. Under the new principle, actuarial gains and losses are immediately recognized through earnings upon remeasurement, at least annually in the fourth quarter, and expected returns on plan assets are recognized using a fair value method. The change in accounting principle will have no effect on our funding requirements, cash flows or employees' benefits. See Retirement Benefits section for additional information on the change in accounting.

We made $63 million of contributions to our pension plans during the first quarter of 2016. We currently anticipate full-year 2016 contributions of approximately $150 million, all of which are required. We made $77 million of contributions to our pension plans during the first quarter of 2015.

Paying dividends – Dividends totaled $448 million in the first quarter of 2016, representing 77 cents per share paid. Each quarter, our Board of Directors reviews the company's dividend for the applicable quarter. The Board evaluates the financial condition of the company and considers the economic outlook, corporate cash flow, the company's liquidity needs, and the health and stability of global credit markets to determine whether to maintain or change the quarterly dividend.

Common stock repurchases – In January 2014, the Board of Directors approved an authorization to repurchase up to $10 billion of Caterpillar common stock (the 2014 Authorization), which will expire on December 31, 2018. We did not purchase any Caterpillar common stock in the first quarter of 2016. As of March 31, 2016, $5.47 billion remained available under the 2014 Authorization. Caterpillar's basic shares outstanding as of March 31, 2016 were approximately 584 million.

Financial Products
Financial Products' operating cash flow was $355 million in the first quarter of 2016, compared with $276 million for the same period a year ago. Net cash used for investing activities was $1.26 billion for the first quarter of 2016, compared with $9 million for the same period in 2015. The change was primarily due to the impact of intercompany lending. Net cash provided by financing

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activities was $916 million for the first quarter of 2016, compared with $72 million for the same period in 2015. The change was primarily due to the impact of intercompany borrowings.

CRITICAL ACCOUNTING POLICIES

For a discussion of the Company's critical accounting policies, see Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations in our 2015 Annual Report on Form 10-K. Critical accounting policies that have been revised since our 2015 Annual Report on Form 10-K are as follows.

Fair values for goodwill impairment tests - We test goodwill for impairment annually, at the reporting unit level, and whenever events or circumstances make it likely that an impairment may have occurred, such as a significant adverse change in the business climate or a decision to sell all or a portion of a reporting unit. We perform our annual goodwill impairment test as of October 1 and monitor for interim triggering events on an ongoing basis.

Goodwill is reviewed for impairment utilizing either a qualitative assessment or a two-step process. If we choose to perform a qualitative assessment and determine the fair value more likely than not exceeds the carrying value, no further evaluation is necessary. For reporting units where we perform the two-step process, the first step requires us to compare the fair value of each reporting unit, which we primarily determine using an income approach based on the present value of discounted cash flows, to the respective carrying value, which includes goodwill. If the fair value of the reporting unit exceeds its carrying value, the goodwill is not considered impaired. If the carrying value is higher than the fair value, there is an indication that an impairment may exist and the second step is required. In step two, the implied fair value of goodwill is calculated as the excess of the fair value of a reporting unit over the fair values assigned to its assets and liabilities. If the implied fair value of goodwill is less than the carrying value of the reporting unit's goodwill, the difference is recognized as an impairment loss.

The impairment test process requires valuation of the respective reporting unit, which we primarily determine using an income approach based on a discounted five year forecasted cash flow with a year-five residual value. The residual value is computed using the constant growth method, which values the forecasted cash flows in perpetuity. The income approach is supported by a reconciliation of our calculated fair value for Caterpillar to the company's market capitalization. The assumptions about future cash flows and growth rates are based on each reporting unit's long-term forecast and are subject to review and approval by senior management. A reporting unit’s discount rate is a risk-adjusted weighted average cost of capital, which we believe approximates the rate from a market participant's perspective. The estimated fair value could be impacted by changes in market conditions, interest rates, growth rates, tax rates, costs, pricing and capital expenditures.

In 2015, our Resource Industries segment had two reporting units with goodwill: Hauling & Extraction and Material Handling & Underground. The October 1, 2015 goodwill impairment test indicated the fair value of the Hauling & Extraction reporting unit exceeded its carrying value by approximately 15 percent, and the fair value of Material Handling & Underground was substantially above its carrying value.

Effective January 1, 2016, product responsibility for off-highway trucks and wheel tractor scrapers transferred from Hauling & Extraction to Material Handling & Underground, and the former Hauling & Extraction reporting unit was renamed Surface Mining & Technology. Surface Mining & Technology’s product portfolio primarily includes large mining trucks, electric rope shovels, draglines, hydraulic shovels and related parts. As a result of the transfer in product responsibility, approximately $500 million of goodwill was reassigned from Hauling & Extraction to Material Handling & Underground based on the relative fair value of the products transferred to the total fair value of Hauling & Extraction. After the reassignment of goodwill, Surface Mining & Technology and Material Handling & Underground had goodwill of approximately $1.2 billion and $2.4 billion, respectively, as of January 1, 2016.

Because the former Hauling & Extraction reporting unit’s fair value was not substantially in excess of its carrying value as of October 1, 2015, we tested Surface Mining & Technology's goodwill for impairment as of January 1, 2016 in conjunction with the transfer of off-highway trucks and wheel tractor scrapers to Material Handling & Underground. The valuation was based on our January 1, 2016 estimates of future cash flows, which continued to reflect weakness in current economic conditions and in the mining industry. Our equipment is used to extract and haul copper, iron ore, coal, oil sands, aggregates, gold and other minerals and ores. The demand for our equipment and related parts is highly cyclical and significantly impacted by commodity prices, although the impact may vary by reporting unit. As of January 1, 2016, we expected sales and cash flows to decline in 2016, and improve over the remainder of the five year forecast period. Based on our estimates for long-term growth, profits and cash flows, the fair value of the Surface Mining & Technology reporting unit continued to exceed its carrying value by approximately 15 percent as of January 1, 2016.

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Currently, we expect Surface Mining & Technology sales to decline about 20 percent in 2016 compared to 2015 as a result of the low commodity price environment and difficult financial conditions for many mining customers around the world. We considered the actual results for the three months ending March 31, 2016 for Surface Mining & Technology along with our most recent sales forecast for 2016 which was substantially consistent with the January 1, 2016 forecast, and concluded a triggering event did not occur at March 31, 2016. No triggering events were identified for the remaining reporting units as of March 31, 2016.

An unfavorable change in our expectations for the financial performance of our reporting units, particularly long-term growth and profitability, would reduce the fair value of our reporting units. The energy and mining industries are major users of our products, including the coal, iron ore, gold, copper, oil and natural gas industries. Decisions to purchase our products are dependent upon the performance of those industries, which in turn are dependent in part on commodity prices. Lower commodity prices or industry specific circumstances that have a negative impact to the valuation assumptions may reduce the fair value of our reporting units. Should such events occur and it becomes more likely than not that a reporting unit's fair value has fallen below its carrying value, we will perform an interim goodwill impairment test(s), in addition to the annual impairment test. Future impairment tests may result in a goodwill impairment, depending on the outcome of both step one and step two of the impairment review process. A goodwill impairment would be reported as a non-cash charge to earnings.

Postretirement benefits - Primary actuarial assumptions were determined as follows:

- The U.S. expected long-term rate of return on plan assets is based on our estimate of long-term passive returns for equities and fixed income securities weighted by the allocation of our plan assets. Based on historical performance, we increase the passive returns due to our active management of the plan assets. A similar process is used to determine the rate for our non-U.S. pension plans. This rate is impacted by changes in general market conditions, but because it represents a long-term rate, it is not significantly impacted by short-term market swings. Changes in our allocation of plan assets would also impact this rate. For example, a shift to more fixed income securities would lower the rate. A decrease in the rate would increase our expense.

- The assumed discount rate is used to discount future benefit obligations back to today’s dollars. The U.S. discount rate is based on a benefit cash flow-matching approach and represents the rate at which our benefit obligations could effectively be settled as of our measurement date, December 31. The benefit cash flow-matching approach involves analyzing Caterpillar’s projected cash flows against a high quality bond yield curve, calculated using a wide population of corporate Aa bonds available on the measurement date. The very highest and lowest yielding bonds (top and bottom 10 percent) are excluded from the analysis. A similar approach is used to determine the assumed discount rate for our most significant non-U.S. plans.

At December 31, 2015, we changed our method for calculating the service and interest cost components of net periodic benefit cost. Historically, these components were determined utilizing a single weighted-average discount rate based on the yield curve used to measure the benefit obligation at the beginning of the period. Beginning in 2016, we elected to utilize a full yield curve approach in the estimation of service and interest costs by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to the relevant projected cash flows. We made this change to provide a more precise measurement of service and interest costs by improving the correlation between the projected cash flows to the corresponding spot rates along the yield curve. This change will have no impact on our pension and other postretirement liabilities and has been accounted for prospectively as a change in accounting estimate beginning in the first quarter of 2016.

Discount rates are sensitive to changes in interest rates. A decrease in the discount rate would increase our obligation and future expense.

- The expected rate of compensation increase is used to develop benefit obligations using projected pay at retirement. It represents average long-term salary increases. This rate is influenced by our long-term compensation policies. An increase in the rate would increase our obligation and expense.

- The assumed health care trend rate represents the rate at which health care costs are assumed to increase and is based on historical and expected experience. Changes in our projections of future health care costs due to general economic conditions and those specific to health care (e.g., technology driven cost changes) will impact this trend rate. An increase in the trend rate would increase our obligation and expense.

The effects of actual results differing from our assumptions and the effects of changing assumptions are considered actuarial gains or losses. At January 1, 2016, we changed our accounting principle for recognizing actuarial gains and losses and expected return on plan assets for our pension and other postretirement benefit plans to a more preferable policy under U.S. GAAP. Under the new principle, actuarial gains and losses will be immediately recognized through earnings upon the annual remeasurement in the fourth quarter, or on an interim basis as triggering events warrant remeasurement. In addition, we have changed our policy for recognizing the expected returns on plan assets from a market-related value method (based on a three-year smoothing of asset returns) to a fair method. These changes have been applied retrospectively to prior years.

See Note 9 for further information regarding the accounting for postretirement benefits.

OTHER MATTERS

Environmental and Legal Matters

The Company is regulated by federal, state and international environmental laws governing our use, transport and disposal of substances and control of emissions. In addition to governing our manufacturing and other operations, these laws often impact the development of our products, including, but not limited to, required compliance with air emissions standards applicable to internal combustion engines. We have made, and will continue to make, significant research and development and capital expenditures to comply with these emissions standards.

We are engaged in remedial activities at a number of locations, often with other companies, pursuant to federal and state laws. When it is probable we will pay remedial costs at a site, and those costs can be reasonably estimated, the investigation, remediation, and operating and maintenance costs are accrued against our earnings. Costs are accrued based on consideration of currently available data and information with respect to each individual site, including available technologies, current applicable laws and regulations, and prior remediation experience. Where no amount within a range of estimates is more likely, we accrue the minimum. Where multiple potentially responsible parties are involved, we consider our proportionate share of the probable costs. In formulating the estimate of probable costs, we do not consider amounts expected to be recovered from insurance companies or others. We reassess these accrued amounts on a quarterly basis. The amount recorded for environmental remediation is not material and is included in Accrued expenses. We believe there is no more than a remote chance that a material amount for remedial activities at any individual site, or at all the sites in the aggregate, will be required.

On January 8, 2015, the Company received a grand jury subpoena from the U.S. District Court for the Central District of Illinois. The subpoena requests documents and information from the Company relating to, among other things, financial information concerning U.S. and non-U.S. Caterpillar subsidiaries (including undistributed profits of non-U.S. subsidiaries and the movement of cash among U.S. and non-U.S. subsidiaries). The Company has received additional subpoenas relating to this investigation requesting additional documents and information relating to, among other things, the purchase and resale of replacement parts by Caterpillar Inc. and non-U.S. Caterpillar subsidiaries, dividend distributions of certain non-U.S. Caterpillar subsidiaries, and Caterpillar SARL and related structures. The Company is cooperating with this investigation. The Company is unable to predict the outcome or reasonably estimate any potential loss; however, we currently believe that this matter will not have a material adverse effect on the Company’s consolidated results of operations, financial position or liquidity.

On September 10, 2014, the SEC issued to Caterpillar a subpoena seeking information concerning the Company’s accounting for the goodwill relating to its acquisition of Bucyrus International Inc. in 2011 and related matters. The Company has received additional subpoenas relating to this investigation, and the Company is cooperating with the SEC regarding its ongoing investigation. The Company is unable to predict the outcome or reasonably estimate any potential loss; however, we currently believe that this matter will not have a material adverse effect on the Company's consolidated results of operations, financial position or liquidity.

On March 20, 2014, Brazil’s Administrative Council for Economic Defense (CADE) published a Technical Opinion which named 18 companies and over 100 individuals as defendants, including two subsidiaries of Caterpillar Inc., MGE - Equipamentos e Serviços Ferroviários Ltda. (MGE) and Caterpillar Brasil Ltda. The publication of the Technical Opinion opened CADE's official administrative investigation into allegations that the defendants participated in anticompetitive bid activity for the construction and maintenance of metro and train networks in Brazil. While companies cannot be held criminally liable for anticompetitive conduct in Brazil, criminal charges have been brought against two current employees of MGE and one former employee of MGE involving the same conduct alleged by CADE. The Company has responded to all requests for information from the authorities. The Company is unable to predict the outcome or reasonably estimate the potential loss; however, we currently believe that this matter will not have a material adverse effect on the Company's consolidated results of operations, financial position or liquidity.

On October 24, 2013, Progress Rail received a grand jury subpoena from the U.S. District Court for the Central District of California. The subpoena requests documents and information from Progress Rail, United Industries Corporation, a wholly-owned subsidiary of Progress Rail, and Caterpillar Inc. relating to allegations that Progress Rail conducted improper or unnecessary railcar inspections and repairs and improperly disposed of parts, equipment, tools and other items. In connection with this subpoena, Progress Rail was informed by the U.S. Attorney for the Central District of California that it is a target of a criminal investigation into potential violations of environmental laws and alleged improper business practices. The Company is cooperating with the authorities and is currently in discussions regarding a potential resolution of the matter. Although the Company believes a loss is probable, we currently believe that this matter will not have a material adverse effect on the Company's consolidated results of operations, financial position or liquidity.

In addition, we are involved in other unresolved legal actions that arise in the normal course of business. The most prevalent of these unresolved actions involve disputes related to product design, manufacture and performance liability (including claimed asbestos and welding fumes exposure), contracts, employment issues, environmental matters or intellectual property rights. The aggregate range of reasonably possible losses in excess of accrued liabilities, if any, associated with these unresolved legal actions is not material. In some cases, we cannot reasonably estimate a range of loss because there is insufficient information regarding the matter. However, we believe there is no more than a remote chance that any liability arising from these matters would be material. Although it is not possible to predict with certainty the outcome of these unresolved legal actions, we believe that these actions will not individually or in the aggregate have a material adverse effect on our consolidated results of operations, financial position or liquidity.

Retirement Benefits

At December 31, 2015, we changed our method for calculating the service and interest cost components of net periodic benefit cost. Historically, these components were determined utilizing a single weighted-average discount rate based on the yield curve used to measure the benefit obligation at the beginning of the period. Beginning in 2016, we elected to utilize a full yield curve approach in the estimation of service and interest costs by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to the relevant projected cash flows. We made this change to provide a more precise measurement of service and interest costs by improving the correlation between the projected cash flows to the corresponding spot rates along the yield curve. This change will have no impact on our year-end pension and OPEB liabilities and has been accounted for prospectively as a change in accounting estimate beginning in the first quarter of 2016. Compared to the method used in 2015, this change lowered pension and OPEB expense by $45 million for the three months ended March 31, 2016, and we expect this change will result in lower pension and OPEB expense by approximately $180 million for 2016.

Effective January 1, 2016, we changed our accounting principle for recognizing actuarial gains and losses and expected return on plan assets for our pension and OPEB plans. Prior to 2016, actuarial gains and losses were recognized as a component of Accumulated other comprehensive income (loss) and were generally amortized into earnings in future periods. Under the new principle, actuarial gains and losses will be immediately recognized through earnings upon the annual remeasurement in the fourth quarter, or on an interim basis as triggering events warrant remeasurement. In addition, we have changed our policy for recognizing the expected returns on plan assets from a market-related value method (based on a three-year smoothing of asset returns) to a fair value method. We believe these changes are preferable as they accelerate the recognition of changes in fair value of plan assets and actuarial gains and losses in our income statement, provide greater transparency of our economic obligations in accounting results and better align with the fair value principles by recognizing the effects of economic and interest rate changes on pension and OPEB assets and liabilities in the year in which the gains and losses are incurred. These changes have been applied retrospectively to prior years.

We recognized a benefit of $10 million related to our defined benefit pension and OPEB plans for the three months ended March 31, 2016, as compared to cost of $16 million for the three months ended March 31, 2015. The decrease in expense is due to lower interest cost primarily due to the adoption of a full yield curve approach in the estimation of interest cost (discussed above) and lower service cost primarily due to fewer employees earning benefits under our plans as a result of the U.S. voluntary retirement enhancement program that was implemented in the fourth quarter of 2015. This is partially offset by an increase in expense due to a lower expected return on plan assets as a result of a lower asset base in 2016 compared to 2015 and a decrease in the expected rate of return on plan assets.

We made $63 million of contributions to our pension plans during the three months ended March 31, 2016. We currently anticipate full-year 2016 contributions of approximately $150 million, all of which are required. We made $77 million of contributions to our pension plans during the three months ended March 31, 2015.

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Order Backlog

The dollar amount of backlog believed to be firm was approximately $13.1 billion at March 31, 2016 and $13.0 billion at December 31, 2015. The order backlog as of March 31, 2016 was about the same in total and by segment as compared to December 31, 2015. Compared to the first quarter of 2015, the order backlog declined about $3.5 billion with decreases in all segments. Of the total backlog, approximately $4.1 billion at March 31, 2016 was not expected to be filled in the following twelve months.

NON-GAAP FINANCIAL MEASURES

The following definitions are provided for the non-GAAP financial measures used in this report. These non-GAAP financial measures have no standardized meaning prescribed by U.S. GAAP and therefore are unlikely to be comparable to the calculation of similar measures for other companies. Management does not intend for these items to be considered in isolation or as a substitute for the related GAAP measures.

We have incurred restructuring costs during the three month periods ending March 31, 2016 and 2015. We believe it is important to separately quantify the profit-per-share impact of restructuring costs in order for our results to be meaningful to our readers as these costs are incurred in the current year to generate longer term benefits. Reconciliation of profit per share excluding restructuring costs to the most directly comparable GAAP measure, profit per share - diluted are as follows:

	Three Months Ended March 31	
	2016	2015
Profit per share - diluted	$0.46	$2.03
Per share restructuring costs [1]	0.21	0.04
Profit per share excluding restructuring costs	$0.67	$2.07

[1] At effective tax rate excluding discrete items.

Supplemental Consolidating Data

We are providing supplemental consolidating data for the purpose of additional analysis. The data has been grouped as follows:

Consolidated – Caterpillar Inc. and its subsidiaries.

Machinery, Energy & Transportation – Caterpillar defines Machinery, Energy & Transportation as it is presented in the supplemental data as Caterpillar Inc. and its subsidiaries with Financial Products accounted for on the equity basis. Machinery, Energy & Transportation information relates to the design, manufacturing and marketing of our products. Financial Products' information relates to the financing to customers and dealers for the purchase and lease of Caterpillar and other equipment. The nature of these businesses is different, especially with regard to the financial position and cash flow items. Caterpillar management utilizes this presentation internally to highlight these differences. We also believe this presentation will assist readers in understanding our business.

Financial Products – Our finance and insurance subsidiaries, primarily Cat Financial and Insurance Services.

Consolidating Adjustments – Eliminations of transactions between Machinery, Energy & Transportation and Financial Products.

Pages 68 to 73 reconcile Machinery, Energy & Transportation with Financial Products on the equity basis to Caterpillar Inc. consolidated financial information.

Caterpillar Inc.
Supplemental Data for Results of Operations
For the Three Months Ended March 31, 2016
(Unaudited)
(Millions of dollars)

		Supplemental Consolidating Data		
	Consolidated	Machinery, Energy & Transportation [1]	Financial Products	Consolidating Adjustments
Sales and revenues:				
Sales of Machinery, Energy & Transportation	$ 8,780	$ 8,780	$ —	$ —
Revenues of Financial Products	681	—	759	(78) [2]
Total sales and revenues	9,461	8,780	759	(78)
Operating costs:				
Cost of goods sold	6,822	6,822	—	—
Selling, general and administrative expenses	1,088	955	139	(6) [3]
Research and development expenses	508	508	—	—
Interest expense of Financial Products	152	—	155	(3) [4]
Other operating (income) expenses	397	105	298	(6) [3]
Total operating costs	8,967	8,390	592	(15)
Operating profit	494	390	167	(63)
Interest expense excluding Financial Products	129	140	—	(11) [4]
Other income (expense)	—	(52)	—	52 [5]
Consolidated profit before taxes	365	198	167	—
Provision (benefit) for income taxes	92	40	52	—
Profit of consolidated companies	273	158	115	—
Equity in profit (loss) of unconsolidated affiliated companies	(1)	(1)	—	—
Equity in profit of Financial Products' subsidiaries	—	114	—	(114) [6]
Profit of consolidated and affiliated companies	272	271	115	(114)
Less: Profit (loss) attributable to noncontrolling interests	1	—	1	—
Profit [7]	$ 271	$ 271	$ 114	$ (114)

1 Represents Caterpillar Inc. and its subsidiaries with Financial Products accounted for on the equity basis.
2 Elimination of Financial Products' revenues earned from Machinery, Energy & Transportation.
3 Elimination of net expenses recorded by Machinery, Energy & Transportation paid to Financial Products.
4 Elimination of interest expense recorded between Financial Products and Machinery, Energy & Transportation.
5

Elimination of discount recorded by Machinery, Energy & Transportation on receivables sold to Financial Products and of interest earned between Machinery, Energy & Transportation and Financial Products.

[6] Elimination of Financial Products' profit due to equity method of accounting.

[7] Profit attributable to common stockholders.

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Caterpillar Inc.
Supplemental Data for Results of Operations
For the Three Months Ended March 31, 2015
(Unaudited)
(Millions of dollars)

	Consolidated	Supplemental Consolidating Data: Machinery, Energy & Transportation [1]	Financial Products	Consolidating Adjustments	
Sales and revenues:					
Sales of Machinery, Energy & Transportation	$ 11,961	$11,961	$ —	$ —	
Revenues of Financial Products	741	—	813	(72)	[2]
Total sales and revenues	12,702	11,961	813	(72)	
Operating costs:					
Cost of goods sold	8,760	8,760	—	—	
Selling, general and administrative expenses	1,249	1,114	133	2	[3]
Research and development expenses	524	524	—	—	
Interest expense of Financial Products	150	—	151	(1)	[4]
Other operating (income) expenses	317	24	299	(6)	[3]
Total operating costs	11,000	10,422	583	(5)	
Operating profit	1,702	1,539	230	(67)	
Interest expense excluding Financial Products	129	139	—	(10)	[4]
Other income (expense)	194	138	(1)	57	[5]
Consolidated profit before taxes	1,767	1,538	229	—	
Provision (benefit) for income taxes	521	453	68	—	
Profit of consolidated companies	1,246	1,085	161	—	
Equity in profit (loss) of unconsolidated affiliated companies	2	2	—	—	
Equity in profit of Financial Products' subsidiaries	—	159	—	(159)	[6]
Profit of consolidated and affiliated companies	1,248	1,246	161	(159)	
Less: Profit (loss) attributable to noncontrolling interests	3	1	2	—	
Profit [7]	$ 1,245	$1,245	$ 159	$ (159)	

[1] Represents Caterpillar Inc. and its subsidiaries with Financial Products accounted for on the equity basis.
[2] Elimination of Financial Products' revenues earned from Machinery, Energy & Transportation.
[3] Elimination of net expenses recorded by Machinery, Energy & Transportation paid to Financial Products.
[4] Elimination of interest expense recorded between Financial Products and Machinery, Energy & Transportation.
[5]

Elimination of discount recorded by Machinery, Energy & Transportation on receivables sold to Financial Products and of interest earned between Machinery, Energy & Transportation and Financial Products.

[6] Elimination of Financial Products' profit due to equity method of accounting.

[7] Profit attributable to common stockholders.

Caterpillar Inc.
Supplemental Data for Financial Position
At March 31, 2016
(Unaudited)
(Millions of dollars)

		Supplemental Consolidating Data			
	Consolidated	Machinery, Energy & Transportation [1]	Financial Products	Consolidating Adjustments	
Assets					
Current assets:					
Cash and short-term investments	$ 5,886	$ 4,744	$ 1,142	$ —	
Receivables – trade and other	6,856	4,528	1,328	1,000	[2,3]
Receivables – finance	9,310	—	13,435	(4,125)	[3]
Prepaid expenses and other current assets	1,847	954	898	(5)	[4]
Inventories	9,849	9,849	—	—	
Total current assets	33,748	20,075	16,803	(3,130)	
Property, plant and equipment – net	15,935	11,668	4,267	—	
Long-term receivables – trade and other	1,159	128	207	824	[2,3]
Long-term receivables – finance	13,527	—	14,381	(854)	[3]
Investments in Financial Products subsidiaries	—	4,194	—	(4,194)	[5]
Noncurrent deferred and refundable income taxes	2,486	3,156	80	(750)	[6]
Intangible assets	2,741	2,735	6	—	
Goodwill	6,710	6,693	17	—	
Other assets	2,001	622	1,392	(13)	[4]
Total assets	$ 78,307	$ 49,271	$ 37,153	$ (8,117)	
Liabilities					
Current liabilities:					
Short-term borrowings	$ 7,817	$ 13	$ 7,804	$ —	
Short-term borrowings with consolidated companies	—	1,000	2,028	(3,028)	[7]
Accounts payable	5,101	5,009	189	(97)	[8]
Accrued expenses	3,142	2,864	278	—	
Accrued wages, salaries and employee benefits	1,158	1,136	22	—	
Customer advances	1,328	1,328	—	—	
Other current liabilities	1,593	1,236	371	(14)	[6,9]
Long-term debt due within one year	6,076	568	5,508	—	
Total current liabilities	26,215	13,154	16,200	(3,139)	
Long-term debt due after one year	24,470	8,944	15,556	(30)	[7]
Liability for postemployment benefits	8,600	8,600	—	—	
Other liabilities	3,269	2,820	1,203	(754)	[6,9]
Total liabilities	62,554	33,518	32,959	(3,923)	
Commitments and contingencies					
Stockholders' equity					
Common stock	5,247	5,247	918	(918)	[5]

Treasury stock	(17,595)	(17,595)	—	—	
Profit employed in the business	29,517	29,517	3,854	(3,854)	5
Accumulated other comprehensive income (loss)	(1,493)	(1,493)	(706)	706	5
Noncontrolling interests	77	77	128	(128)	5
Total stockholders' equity	15,753	15,753	4,194	(4,194)	
Total liabilities and stockholders' equity	$ 78,307	$ 49,271	$ 37,153	$ (8,117)	

1 Represents Caterpillar Inc. and its subsidiaries with Financial Products accounted for on the equity basis.
2 Elimination of receivables between Machinery, Energy & Transportation and Financial Products.
3 Reclassification of Machinery, Energy & Transportation's trade receivables purchased by Financial Products and Financial Products' wholesale inventory receivables.
4 Elimination of Machinery, Energy & Transportation's insurance premiums that are prepaid to Financial Products.
5 Elimination of Financial Products' equity which is accounted for by Machinery, Energy & Transportation on the equity basis.
6 Reclassification reflecting required netting of deferred tax assets / liabilities by taxing jurisdiction.
7 Elimination of debt between Machinery, Energy & Transportation and Financial Products.
8 Elimination of payables between Machinery, Energy & Transportation and Financial Products.
9 Elimination of prepaid insurance in Financial Products' other liabilities.

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Caterpillar Inc.
Supplemental Data for Financial Position
At December 31, 2015
(Unaudited)
(Millions of dollars)

		Supplemental Consolidating Data			
	Consolidated	Machinery, Energy & Transportation [1]	Financial Products	Consolidating Adjustments	
Assets					
Current assets:					
Cash and short-term investments	$ 6,460	$ 5,340	$ 1,120	$ —	
Receivables – trade and other	6,695	3,564	345	2,786	[2,3]
Receivables – finance	8,991	—	12,891	(3,900	) [3]
Prepaid expenses and other current assets	1,662	817	850	(5	) [4]
Inventories	9,700	9,700	—	—	
Total current assets	33,508	19,421	15,206	(1,119	)
Property, plant and equipment – net	16,090	11,888	4,202	—	
Long-term receivables – trade and other	1,170	121	215	834	[2,3]
Long-term receivables – finance	13,651	—	14,516	(865	) [3]
Investments in Financial Products subsidiaries	—	3,888	—	(3,888	) [5]
Noncurrent deferred and refundable income taxes	2,489	3,208	74	(793	) [6]
Intangible assets	2,821	2,815	6	—	
Goodwill	6,615	6,598	17	—	
Other assets	1,998	612	1,400	(14	) [4]
Total assets	$ 78,342	$ 48,551	$ 35,636	$ (5,845	)
Liabilities					
Current liabilities:					
Short-term borrowings	$ 6,967	$ 9	$ 6,958	$ —	
Short-term borrowings with consolidated companies	—	—	1,096	(1,096	) [7]
Accounts payable	5,023	4,848	193	(18	) [8]
Accrued expenses	3,116	2,841	275	—	
Accrued wages, salaries and employee benefits	1,994	1,951	43	—	
Customer advances	1,146	1,146	—	—	
Dividends payable	448	448	—	—	
Other current liabilities	1,671	1,315	373	(17	) [6,9]
Long-term debt due within one year	5,877	517	5,360	—	
Total current liabilities	26,242	13,075	14,298	(1,131	)
Long-term debt due after one year	25,169	8,991	16,209	(31	) [7]
Liability for postemployment benefits	8,843	8,843	—	—	
Other liabilities	3,203	2,757	1,241	(795	) [6,9]
Total liabilities	63,457	33,666	31,748	(1,957	)
Commitments and contingencies					
Stockholders' equity					

Common stock	5,238	5,238	911	(911)	[5]
Treasury stock	(17,640)	(17,640)	—	—	
Profit employed in the business	29,246	29,246	3,747	(3,747)	[5]
Accumulated other comprehensive income (loss)	(2,035)	(2,035)	(896)	896	[5]
Noncontrolling interests	76	76	126	(126)	[5]
Total stockholders' equity	14,885	14,885	3,888	(3,888)	
Total liabilities and stockholders' equity	$ 78,342	$ 48,551	$ 35,636	$ (5,845)	

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[7] Elimination of debt between Machinery, Energy & Transportation and Financial Products.
[8] Elimination of payables between Machinery, Energy & Transportation and Financial Products.
[9] Elimination of prepaid insurance in Financial Products' other liabilities.

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Caterpillar Inc.
Supplemental Data for Cash Flow
For the Three Months Ended March 31, 2016
(Unaudited)
(Millions of dollars)

		Supplemental Consolidating Data			
	Consolidated	Machinery, Energy & Transportation [1]	Financial Products	Consolidating Adjustments	
Cash flow from operating activities:					
Profit of consolidated and affiliated companies	$ 272	$ 271	$ 115	$ (114)	[2]
Adjustments for non-cash items:					
Depreciation and amortization	740	525	215	—	
Undistributed profit of Financial Products	—	(107)	—	107	[3]
Other	269	204	16	49	[4]
Changes in assets and liabilities, net of acquisitions and divestitures:					
Receivables - trade and other	14	41	20	(47)	[4, 5]
Inventories	(74)	(74)	—	—	
Accounts payable	211	288	2	(79)	[4]
Accrued expenses	33	34	(1)	—	
Accrued wages, salaries and employee benefits	(852)	(831)	(21)	—	
Customer advances	174	174	—	—	
Other assets – net	(145)	(118)	17	(44)	[4]
Other liabilities – net	(153)	(189)	(8)	44	[4]
Net cash provided by (used for) operating activities	489	218	355	(84)	
Cash flow from investing activities:					
Capital expenditures - excluding equipment leased to others	(357)	(356)	(1)	—	
Expenditures for equipment leased to others	(383)	(23)	(369)	9	[4]
Proceeds from disposals of leased assets and property, plant and equipment	173	21	159	(7)	[4]
Additions to finance receivables	(2,014)	—	(2,662)	648	[5]
Collections of finance receivables	2,047	—	2,849	(802)	[5]
Net intercompany purchased receivables	—	—	(229)	229	[5]
Proceeds from sale of finance receivables	10	—	10	—	
Net intercompany borrowings	—	(927)	(1,000)	1,927	[6]
Investments and acquisitions (net of cash acquired)	(12)	(12)	—	—	
Proceeds from sale of securities	49	4	45	—	
Investments in securities	(62)	(5)	(57)	—	
Other – net	(23)	(23)	(7)	7	[8]
Net cash provided by (used for) investing activities	(572)	(1,321)	(1,262)	2,011	
Cash flow from financing activities:					
Dividends paid	(448)	(448)	(7)	7	[7]
Distribution to noncontrolling interests	(1)	(1)	—	—	
Common stock issued, including treasury shares reissued	(45)	(45)	7	(7)	[8]

Excess tax benefit from stock-based compensation	1	1	—	—
Net intercompany borrowings	—	1,000	927	(1,927) [6]
Proceeds from debt issued (original maturities greater than three months)	1,211	1	1,210	—
Payments on debt (original maturities greater than three months)	(1,706)	(3)	(1,703)	—
Short-term borrowings – net (original maturities three months or less)	486	4	482	—
Net cash provided by (used for) financing activities	(502)	509	916	(1,927)
Effect of exchange rate changes on cash	11	(2)	13	—
Increase (decrease) in cash and short-term investments	(574)	(596)	22	—
Cash and short-term investments at beginning of period	6,460	5,340	1,120	—
Cash and short-term investments at end of period	$ 5,886	$ 4,744	$ 1,142	$ —

[1] Represents Caterpillar Inc. and its subsidiaries with Financial Products accounted for on the equity basis.
[2] Elimination of Financial Products' profit after tax due to equity method of accounting.
[3] Elimination of non-cash adjustment for the undistributed earnings from Financial Products.
[4] Elimination of non-cash adjustments and changes in assets and liabilities related to consolidated reporting.
[5] Reclassification of Financial Products' cash flow activity from investing to operating for receivables that arose from the sale of inventory.
[6] Elimination of net proceeds and payments to/from Machinery, Energy & Transportation and Financial Products.
[7] Elimination of dividend from Financial Products to Machinery, Energy & Transportation.
[8] Elimination of change in investment and common stock related to Financial Products.

Caterpillar Inc.
Supplemental Data for Cash Flow
For the Three Months Ended March 31, 2015
(Unaudited)
(Millions of dollars)

		Supplemental Consolidating Data		
	Consolidated	Machinery, Energy & Transportation [1]	Financial Products	Consolidating Adjustments
Cash flow from operating activities:				
Profit of consolidated and affiliated companies	$ 1,248	$ 1,246	$ 161	$ (159) [2]
Adjustments for non-cash items:				
Depreciation and amortization	753	530	223	—
Undistributed profit of Financial Products	—	(59)	—	59 [3]
Other	(88)	(55)	(87)	54 [4]
Changes in assets and liabilities, net of acquisitions and divestitures:				
Receivables - trade and other	6	54	(34)	(14) [4, 5]
Inventories	(89)	(85)	—	(4) [4]
Accounts payable	228	169	43	16 [4]
Accrued expenses	35	26	9	—
Accrued wages, salaries and employee benefits	(1,027)	(1,009)	(18)	—
Customer advances	25	25	—	—
Other assets – net	365	246	36	83 [4]
Other liabilities – net	(186)	(46)	(57)	(83) [4]
Net cash provided by (used for) operating activities	1,270	1,042	276	(48)
Cash flow from investing activities:				
Capital expenditures - excluding equipment leased to others	(437)	(435)	(2)	—
Expenditures for equipment leased to others	(389)	(42)	(355)	8 [4]
Proceeds from disposals of leased assets and property, plant and equipment	167	6	162	(1) [4]
Additions to finance receivables	(2,122)	—	(2,901)	779 [5,8]
Collections of finance receivables	2,241	—	2,954	(713) [5]
Net intercompany purchased receivables	—	—	118	(118) [5]
Proceeds from sale of finance receivables	43	—	43	—
Net intercompany borrowings	—	(8)	—	8 [6]
Investments and acquisitions (net of cash acquired)	(29)	(29)	—	—
Proceeds from sale of businesses and investments (net of cash sold)	167	174	—	(7) [8]
Proceeds from sale of securities	83	3	80	—
Investments in securities	(70)	(4)	(66)	—
Other – net	(38)	4	(42)	—
Net cash provided by (used for) investing activities	(384)	(331)	(9)	(44)
Cash flow from financing activities:				
Dividends paid	(424)	(424)	(100)	100 [7]

Distribution to noncontrolling interests	(7	)	(7	)	—		—		
Common stock issued, including treasury shares reissued	32		32		—		—		
Treasury shares purchased	(400	)	(400	)	—		—		
Excess tax benefit from stock-based compensation	17		17		—		—		
Net intercompany borrowings	—		—		8		(8	)	6
Proceeds from debt issued (original maturities greater than three months)	1,529		2		1,527		—		
Payments on debt (original maturities greater than three months)	(2,319	)	(6	)	(2,313	)	—		
Short-term borrowings – net (original maturities three months or less)	950		—		950		—		
Net cash provided by (used for) financing activities	(622	)	(786	)	72		92		
Effect of exchange rate changes on cash	(42	)	(24	)	(18	)	—		
Increase (decrease) in cash and short-term investments	222		(99	)	321		—		
Cash and short-term investments at beginning of period	7,341		6,317		1,024		—		
Cash and short-term investments at end of period	$ 7,563		$ 6,218		$ 1,345		$ —		

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7 Elimination of dividend from Financial Products to Machinery, Energy & Transportation.
8 Elimination of proceeds received from Financial Products related to Machinery, Energy & Transportation's sale of businesses and investments.

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Forward-looking Statements

Certain statements in this Form 10-Q relate to future events and expectations and are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Words such as “believe,” “estimate,” “will be,” “will,” “would,” “expect,” “anticipate,” “plan,” “project,” “intend,” “could,” “should” or other similar words or expressions oft forward-looking statements. All statements other than statements of historical fact are forward-looking statements, including, without limitation, statements regarding our outlook, projections, forecasts or trend descriptions. These statements do not guarantee future performance, and we do not undertake to update our forward-looking statements.

Caterpillar’s actual results may differ materially from those described or implied in our forward-looking statements based on a number of factors, including, but not limited to: (i) global and regional economic conditions and economic conditions in the industries we serve; (ii) government monetary or fiscal policies and infrastructure spending; (iii) commodity price changes, component price increases, fluctuations in demand for our products or significant shortages of component products; (iv) disruptions or volatility in global financial markets limiting our sources of liquidity or the liquidity of our customers, dealers and suppliers; (v) political and economic risks, commercial instability and events beyond our control in the countries in which we operate; (vi) failure to maintain our credit ratings and potential resulting increases to our cost of borrowing and adverse effects on our cost of funds, liquidity, competitive position and access to capital markets; (vii) our Financial Products segment’s risks associated with the financial services industry; (viii) changes in interest rates or market liquidity conditions; (ix) an increase in delinquencies, repossessions or net losses of Cat Financial’s customers; (x) new regulations or changes in financial services regulations; (xi) a failure to realize, or a delay in realizing, all of the anticipated benefits of our acquisitions, joint ventures or divestitures; (xii) international trade policies and their impact on demand for our products and our competitive position; (xiii) our ability to develop, produce and market quality products that meet our customers’ needs; (xiv) the impact of the highly competitive environment in which we operate on our sales and pricing; (xv) failure to realize all of the anticipated benefits from initiatives to increase our productivity, efficiency and cash flow and to reduce costs; (xvi) additional restructuring costs or a failure to realize anticipated savings or benefits from past or future cost reduction actions; (xvii) inventory management decisions and sourcing practices of our dealers and our OEM customers; (xviii) compliance with environmental laws and regulations; (xix) alleged or actual violations of trade or anti-corruption laws and regulations; (xx) additional tax expense or exposure; (xxi) currency fluctuations; (xxii) our or Cat Financial’s compliance with financial covenants; (xxiii) increased pension plan funding obligations; (xxiv) union disputes or other employee relations issues; (xxv) significant legal proceedings, claims, lawsuits or government investigations; (xxvi) changes in accounting standards; (xxvii) failure or breach of IT security; (xxviii) adverse effects of unexpected events including natural disasters; and (xxix) other factors described in more detail under “Item 1A. Risk Factors” in our Form 10-K filed with the SEC on February 16, 2016 for the year ended December 31, 2015.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The information required by this Item is incorporated by reference from Note 4 – “Derivative financial instruments and risk management” included in Part I, Item 1 and Management’s Discussion and Analysis included in Part I, Item 2 of this Form 10-Q.

Item 4. Controls and Procedures

Evaluation of disclosure controls and procedures

An evaluation was performed under the supervision and with the participation of the company’s management, including the Chief Executive Officer (CEO) and Chief Financial Officer (CFO), of the effectiveness of the design and operation of the company’s disclosure controls and procedures, as that term is defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended, as of the end of the period covered by this quarterly report. Based on that evaluation, the CEO and CFO concluded that the company’s disclosure controls and procedures are effective as of the end of the period covered by this quarterly report.

Changes in internal control over financial reporting

During the first quarter of 2016, there has been no change in the company's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the company’s internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The information required by this Item is incorporated by reference from Note 13 – "Environmental and legal matters" included in Part I, Item 1 of this Form 10-Q.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Issuer Purchases of Equity Securities
No shares were repurchased during the first quarter of 2016.

Other Purchases of Equity Securities

Period	Total Number of Shares Purchased [1]	Average Price Paid per Share	Total Number of Shares Purchased Under the Program	Approximate Dollar Value of Shares that may yet be Purchased under the Program
January 1-31, 2016	16,237	$ 65.85	N/A	N/A
February 1-29, 2016	3,028	$ 67.32	N/A	N/A
March 1-31, 2016	589,457	$ 71.68	N/A	N/A
Total	608,722	$ 71.50		

[1] Represents shares delivered back to issuer for the payment of taxes resulting from the vesting of restricted stock units for employees and Directors.

Non-U.S. Employee Stock Purchase Plans

As of March 31, 2016, we had 29 employee stock purchase plans (the "EIP Plans") that are administered outside the United States for our non-U.S. employees, which had approximately 14,000 active participants in the aggregate. During the first quarter of 2016, approximately 267,000 shares of Caterpillar common stock were purchased by the EIP Plans pursuant to the terms of such plans.

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Item 6. Exhibits

11	Computations of Earnings per Share (included in Note 11 of this Form 10-Q filed for the quarter ended March 31, 2016).
18.1	Letter of PricewaterhouseCoopers LLP, dated May 2, 2016, relating to change in accounting principles.
31.1	Certification of Douglas R. Oberhelman, Chairman and Chief Executive Officer of Caterpillar Inc., as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Bradley M. Halverson, Group President and Chief Financial Officer of Caterpillar Inc., as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	Certification of Douglas R. Oberhelman, Chairman and Chief Executive Officer of Caterpillar Inc. and Bradley M. Halverson, Group President and Chief Financial Officer of Caterpillar Inc., as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

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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.

CATERPILLAR INC.

May 2, 2016	/s/ Douglas R. Oberhelman (Douglas R. Oberhelman)	Chairman and Chief Executive Officer
May 2, 2016	/s/ Bradley M. Halverson (Bradley M. Halverson)	Group President and Chief Financial Officer
May 2, 2016	/s/ James B. Buda (James B. Buda)	Executive Vice President, Law and Public Policy
May 2, 2016	/s/ Jananne A. Copeland (Jananne A. Copeland)	Chief Accounting Officer

EXHIBIT INDEX

Exhibit No.	Description
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