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Public Service Commission of Utah
160 East 300 South
P.O. Box 45585
Salt Lake City, UT 84145-0585

Dear Commission:

Docket No. 11-999-01

Enclosed is a copy of PacifiCorp's most recent quarterly report on Form 10-K for the period ended December 31, 2010, as filed with the Securities and Exchange Commission pursuant to the requirement of the Securities Exchange Act of 1934.

Very Truly Yours,

Ryan Weems
External Reporting Manager

Enclosure

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

FORM 10-K

☒ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2010
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	Exact name of registrant as specified in its charter; State or other jurisdiction of incorporation or organization	IRS Employer Identification No.
1-5152	PACIFICORP (An Oregon Corporation) 825 N.E. Multnomah Street Portland, Oregon 97232 503-813-5608	93-0246090

Securities registered pursuant to Section 12(b) of the Act: None
Securities registered pursuant to Section 12(g) of the Act:

Title of each Class

5% Preferred Stock (Cumulative; \$100 Stated Value)
Serial Preferred Stock (Cumulative; \$100 Stated Value)
No Par Serial Preferred Stock (Cumulative; \$100 Stated Value)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☒ 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 ☒

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 ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ 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 the 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. ☒

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 the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒ Smaller reporting company ☐

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

All shares of outstanding common stock of PacificCorp are indirectly owned by MidAmerican Energy Holdings Company, 666 Grand Avenue, Des Moines, Iowa 50309. As of January 31, 2011, 357,060,915 shares of common stock were outstanding.

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Forward-Looking Statements

This report contains statements that do not directly or exclusively relate to historical facts. These statements are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements can typically be identified by the use of forward-looking words, such as "will," "may," "could," "project," "believe," "anticipate," "expect," "estimate," "continue," "intend," "potential," "plan," "forecast" and similar terms. These statements are based upon PacifiCorp's current intentions, assumptions, expectations and beliefs and are subject to risks, uncertainties and other important factors. Many of these factors are outside PacifiCorp's control and could cause actual results to differ materially from those expressed or implied by PacifiCorp's forward-looking statements. These factors include, among others:

- general economic, political and business conditions, as well as changes in laws and regulations affecting PacifiCorp's operations or related industries;
- changes in, and compliance with, environmental laws, regulations, decisions and policies that could, among other items, increase operating and capital costs, reduce generating facility output, accelerate generating facility retirements or delay generating facility construction or acquisition;
- the outcome of general rate cases and other proceedings conducted by regulatory commissions or other governmental and legal bodies;
- changes in economic, industry or weather conditions, as well as demographic trends, that could affect customer growth and usage or electricity supply or PacifiCorp's ability to obtain long-term contracts with wholesale customers and suppliers;
- a high degree of variance between actual and forecasted load that could impact PacifiCorp's hedging strategy and the cost of balancing its generation resources and wholesale activities with its retail load obligations;
- performance and availability of PacifiCorp's generating facilities, including the impacts of outages or repairs, transmission constraints, weather and operating conditions;
- hydroelectric conditions, as well as the cost, feasibility and eventual outcome of hydroelectric relicensing proceedings, that could have a significant impact on electricity capacity and cost and PacifiCorp's ability to generate electricity;
- changes in prices, availability and demand for both purchases and sales of wholesale electricity, coal, natural gas, other fuel sources and fuel transportation that could have a significant impact on generating capacity and energy costs;
- the financial condition and creditworthiness of PacifiCorp's significant customers and suppliers;
- changes in business strategy or development plans;
- availability, terms and deployment of capital, including reductions in demand for investment-grade commercial paper, debt securities and other sources of debt financing and volatility in the London Interbank Offered Rate, the base interest rate for PacifiCorp's credit facilities;
- changes in PacifiCorp's credit ratings;
- the impact of derivative contracts used to mitigate or manage volume, price and interest rate risk, including increased collateral requirements, and changes in commodity prices, interest rates and other conditions that affect the fair value of derivative contracts;
- the impact of inflation on costs and our ability to recover such costs in rates;
- increases in employee healthcare costs;
- the impact of investment performance and changes in interest rates, legislation, healthcare cost trends, mortality and morbidity on expense and funding requirements associated with PacifiCorp's pension and other postretirement benefits plans and the joint trust plans to which PacifiCorp contributes;

- unanticipated construction delays, changes in costs, receipt of required permits and authorizations, ability to fund capital projects and other factors that could affect future generating facilities and infrastructure additions;
- the impact of new accounting guidance or changes in current accounting estimates and assumptions on consolidated financial results;
- other risks or unforeseen events, including the effects of storms, floods, litigation, wars, terrorism, embargoes and other catastrophic events; and
- other business or investment considerations that may be disclosed from time to time in PacifiCorp's filings with the United States Securities and Exchange Commission ("SEC") or in other publicly disseminated written documents.

Further details of the potential risks and uncertainties affecting PacifiCorp are described in Item 1A and other discussions contained in this Form 10-K. PacifiCorp undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing review of factors should not be construed as exclusive.

PART I

Item 1. Business

General

PacifiCorp, which includes PacifiCorp and its subsidiaries, is a United States regulated electric company serving 1.7 million retail customers, including residential, commercial, industrial and other customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp owns, or has interests in, 78 thermal, hydroelectric, wind-powered and geothermal generating facilities, with a net owned capacity of 10,623 megawatts ("MW"). PacifiCorp also owns, or has interests in, electric transmission and distribution assets, and transmits electricity through approximately 16,200 miles of transmission lines. PacifiCorp also buys and sells electricity on the wholesale market with public and private utilities, energy marketing companies and incorporated municipalities as a result of excess electricity generation or other system balancing activities. PacifiCorp is subject to comprehensive state and federal regulation. PacifiCorp's subsidiaries support its electric utility operations by providing coal mining and environmental remediation services. PacifiCorp is an indirect subsidiary of MidAmerican Energy Holdings Company ("MEHC"), a holding company based in Des Moines, Iowa, that owns subsidiaries principally engaged in energy businesses. MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway"). MEHC controls substantially all of PacifiCorp's voting securities, which include both common and preferred stock.

PacifiCorp's principal executive offices are located at 825 N.E. Multnomah Street, Portland, Oregon 97232, and its telephone number is (503) 813-5608. PacifiCorp was initially incorporated in 1910 under the laws of the state of Maine under the name Pacific Power & Light Company. In 1984, Pacific Power & Light Company changed its name to PacifiCorp. In 1989, it merged with Utah Power and Light Company, a Utah corporation, in a transaction wherein both corporations merged into a newly-formed Oregon corporation. The resulting Oregon corporation was re-named PacifiCorp, which is the operating entity today.

Berkshire Hathaway Equity Commitment

In March 2006, MEHC and Berkshire Hathaway entered into an Equity Commitment Agreement ("Berkshire Equity Commitment") pursuant to which Berkshire Hathaway has agreed to purchase up to \$3.5 billion of MEHC's common equity upon any requests authorized from time to time by MEHC's Board of Directors. The proceeds of any such equity contribution shall only be used by MEHC for the purpose of (a) paying when due MEHC's debt obligations and (b) funding the general corporate purposes and capital requirements of MEHC's regulated subsidiaries, including PacifiCorp. Berkshire Hathaway will have up to 180 days to fund any such request in increments of at least \$250 million pursuant to one or more drawings authorized by MEHC's Board of Directors. The funding of each drawing will be made by means of a cash equity contribution to MEHC in exchange for additional shares of MEHC's common stock. PacifiCorp has no right to make or to cause MEHC to make any equity contribution requests. In March 2010, MEHC and Berkshire Hathaway amended the Berkshire Equity Commitment extending the term from February 28, 2011 to February 28, 2014 and reducing the \$3.5 billion to \$2.0 billion effective March 1, 2011.

Operations

PacifiCorp delivers electricity to customers in Utah, Wyoming and Idaho under the trade name Rocky Mountain Power and to customers in Oregon, Washington and California under the trade name Pacific Power. PacifiCorp's electric generation, commercial and trading, and coal mining functions are operated under the trade name PacifiCorp Energy. As a vertically integrated electric utility, PacifiCorp owns or has contracts for fuel sources, such as coal and natural gas, and uses these fuel sources, as well as water resources, wind and geothermal to generate electricity at its generating facilities. This electricity, together with electricity purchased on the wholesale market, is then transmitted via a grid of transmission lines throughout PacifiCorp's six-state service area and the Western United States. The electricity is then transformed to lower voltages and delivered to customers through PacifiCorp's distribution system.

PacifiCorp's primary goal is to provide safe, reliable electricity to its customers at a reasonable cost. In return, PacifiCorp expects that all prudently incurred costs to provide such service will be included as allowable costs for ratemaking purposes, and PacifiCorp will be allowed an opportunity to earn a reasonable return on its investments.

PacifiCorp seeks to manage growth in its customer demand through the construction and purchase of new cost-effective, environmentally prudent and efficient sources of power supply and through demand response and energy efficiency programs. During 2010, PacifiCorp placed in service its 111-MW Dunlap Ranch I wind-powered generating facility and began purchasing the entire output of a 200-MW wind-powered generating facility to help meet future retail load growth, achieve renewable generation targets and replace expiring wholesale supply contracts.

Employees

As of December 31, 2010, PacifiCorp, together with its subsidiaries, had approximately 6,300 employees, of which approximately 3,800 were covered by union contracts, principally with the International Brotherhood of Electrical Workers, the Utility Workers Union of America, the International Brotherhood of Boilermakers and the United Mine Workers of America.

Service Territories

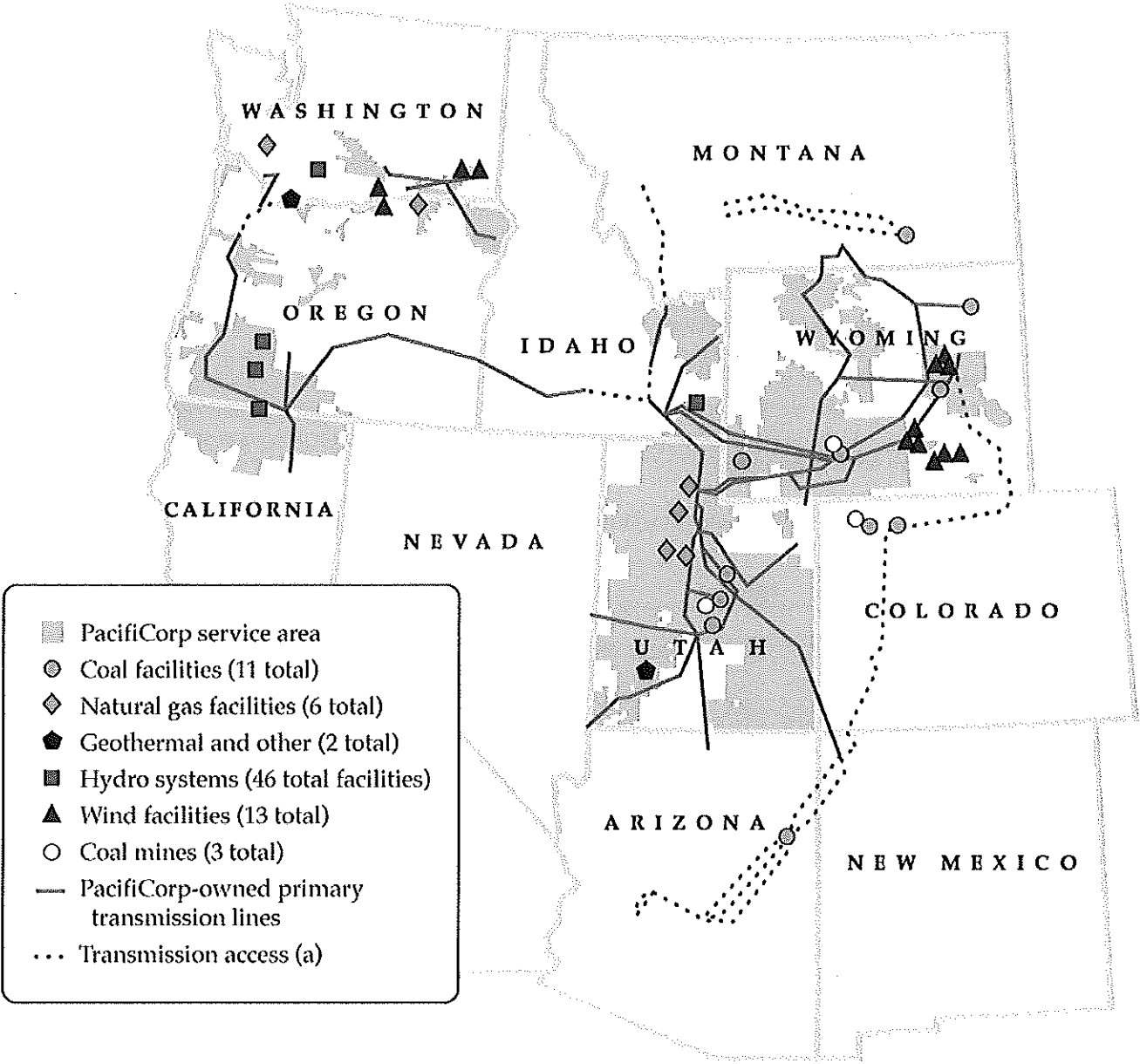
PacifiCorp's combined service territory covers approximately 136,000 square miles and includes diverse regional economies ranging from rural, agricultural and mining areas to urban, manufacturing and government service centers. No single segment of the economy dominates the service territory, which helps mitigate PacifiCorp's exposure to economic fluctuations. In the eastern portion of the service territory, mainly consisting of Utah, Wyoming and southeastern Idaho, the principal industries are manufacturing, recreation, agriculture and mining or extraction of natural resources. In the western portion of the service territory, mainly consisting of Oregon, southern Washington and northern California, the principal industries are agriculture and manufacturing, with forest products, food processing, technology and primary metals being the largest industrial sectors. In addition to retail sales, PacifiCorp sells electricity to other utilities, municipalities and energy marketing companies on a wholesale basis.

PacifiCorp's operations are conducted under numerous franchise agreements, certificates, permits and licenses obtained from federal, state and local authorities. The average term of these agreements is approximately 30 years, although their terms range from five years to indefinite. PacifiCorp generally has an exclusive right to serve electric customers within its service territories and, in turn, has an obligation to provide electric service to those customers. In return, the state utility commissions have established rates on a cost-of-service basis, which are designed to allow PacifiCorp an opportunity to recover its costs of providing services and to earn a reasonable return on its investment.

The percentages of electricity sold to retail customers by jurisdiction were as follows for the years ended December 31:

	2010	2009	2008
Utah	42 %	42 %	42 %
Oregon	24	25	26
Wyoming	18	17	17
Washington	8	8	7
Idaho	6	6	6
California	2	2	2
	<u>100 %</u>	<u>100 %</u>	<u>100 %</u>

The following map highlights PacifiCorp's retail service territory, generating facility locations, coal mines in which PacifiCorp has an interest and PacifiCorp's primary transmission lines as of December 31, 2010. PacifiCorp's generating facilities are interconnected through PacifiCorp's own transmission lines or by contract through transmission lines owned by others.



(a) Access to other entities' transmission lines through wheeling arrangements.

Customers

Electricity sold to retail and wholesale customers by class of customer, total gigawatt hours ("GWh") sold and the average number of retail customers for the years ended December 31 were as follows:

	2010		2009		2008	
GWh sold:						
Residential	15,795	24%	15,999	24%	16,222	24%
Commercial	15,969	25	16,194	25	16,055	24
Industrial	20,680	32	19,934	31	21,495	32
Other	572	1	583	1	590	1
Total retail	53,016	82	52,710	81	54,362	81
Wholesale	11,415	18	12,349	19	12,345	19
Total GWh sold	64,431	100%	65,059	100%	66,707	100%
Average number of retail customers (in thousands):						
Residential	1,475	85%	1,467	85%	1,458	86%
Commercial	220	13	214	13	210	12
Industrial	34	2	34	2	34	2
Other	4	—	4	—	4	—
Total	1,733	100%	1,719	100%	1,706	100%
Retail customers:						
Average usage per customer (kilowatt hours)	30,595		30,672		31,863	
Average revenue per customer	\$ 2,142		\$ 2,076		\$ 2,043	
Revenue per kilowatt hour	7.0¢		6.8¢		6.4¢	

Customer Usage and Seasonality

In addition to the variations in weather from year to year, fluctuations in economic conditions within PacifiCorp's service territory and elsewhere can impact customer usage, particularly for industrial and wholesale customers. Beginning in the fourth quarter of 2008, certain customer usage levels began to decline due to the effects of the economic conditions in the United States. The declining usage trend continued during 2009, resulting in lower retail demand compared to 2008. The declining usage trend reversed during 2010 in the eastern side of PacifiCorp's service territory although partially offset by unfavorable weather conditions. The declining usage trend continued during 2010 in the western side of PacifiCorp's service territory.

Peak customer demand is typically highest in the summer across PacifiCorp's service territory when air conditioning and irrigation systems are heavily used. The service territory also has a winter peak, which is primarily due to heating requirements in the western portion of PacifiCorp's service territory. Peak demand represents the highest demand on a given day and at a given hour. During 2010, PacifiCorp's peak demand was 9,418 MW in the summer and 8,592 MW in the winter.

Generating Facilities and Fuel Supply

The percentage of PacifiCorp's energy supplied by energy source varies from year to year and is subject to numerous operational and economic factors such as planned and unplanned outages; fuel commodity prices; fuel transportation costs; weather; environmental considerations; transmission constraints; and wholesale market prices of electricity. When factors for one energy source are less favorable, PacifiCorp must place more reliance on other energy sources. For example, PacifiCorp can generate more electricity using its low cost hydroelectric and wind-powered generating facilities when factors associated with these facilities are favorable. When factors associated with hydroelectric and wind resources are less favorable, PacifiCorp must increase its reliance on more expensive generation or purchased electricity. PacifiCorp manages certain risks relating to its supply of electricity and fuel requirements by entering into various contracts, which may be accounted for as derivatives, including forwards, futures, options, swaps and other agreements. Refer to Item 7A in this Form 10-K for a discussion of commodity price risk and derivative contracts.

PacifiCorp has ownership interest in a diverse portfolio of generating facilities. The following table presents certain information concerning PacifiCorp's owned generating facilities as of December 31, 2010:

	Location	Energy Source	Installed	Facility Net Capacity (MW) ⁽¹⁾	Net Owned Capacity (MW) ⁽¹⁾
COAL:					
Jim Bridger	Rock Springs, WY	Coal	1974-1979	2,118	1,412
Hunter Nos. 1, 2 and 3	Castle Dale, UT	Coal	1978-1983	1,336	1,137
Huntington	Huntington, UT	Coal	1974-1977	911	911
Dave Johnston	Glenrock, WY	Coal	1959-1972	762	762
Naughton	Kemmerer, WY	Coal	1963-1971	700	700
Cholla No. 4	Joseph City, AZ	Coal	1981	395	395
Wyodak	Gillette, WY	Coal	1978	335	268
Carbon	Castle Gate, UT	Coal	1954-1957	172	172
Craig Nos. 1 and 2	Craig, CO	Coal	1979-1980	856	165
Colstrip Nos. 3 and 4	Colstrip, MT	Coal	1984-1986	1,480	148
Hayden Nos. 1 and 2	Hayden, CO	Coal	1965-1976	446	78
				9,511	6,148
NATURAL GAS:					
Lake Side	Vineyard, UT	Natural gas/steam	2007	558	558
Currant Creek	Mona, UT	Natural gas/steam	2005-2006	550	550
Chehalis	Chehalis, WA	Natural gas/steam	2003	520	520
Hermiston	Hermiston, OR	Natural gas/steam	1996	474	237
Gadsby Steam	Salt Lake City, UT	Natural gas	1951-1955	231	231
Gadsby Peak	Salt Lake City, UT	Natural gas	2002	120	120
Little Mountain	Ogden, UT	Natural gas	1971	14	14
				2,467	2,230
HYDROELECTRIC: ⁽²⁾					
Lewis River System ⁽³⁾	WA	Hydroelectric	1931-1958	578	578
North Umpqua River System ⁽⁴⁾	OR	Hydroelectric	1950-1956	200	200
Klamath River System ⁽⁵⁾	CA, OR	Hydroelectric	1903-1962	170	170
Bear River System ⁽⁶⁾	ID, UT	Hydroelectric	1908-1984	105	105
Rogue River System ⁽⁷⁾	OR	Hydroelectric	1912-1957	52	52
Minor hydroelectric facilities	Various	Hydroelectric	1895-1986	52	52
				1,157	1,157
WIND: ⁽²⁾					
Marengo	Dayton, WA	Wind	2007	140	140
Dunlap Ranch I	Medicine Bow, WY	Wind	2010	111	111
Leaning Juniper I	Arlington, OR	Wind	2006	101	101
High Plains	McFadden, WY	Wind	2009	99	99
Rolling Hills	Glenrock, WY	Wind	2009	99	99
Glenrock	Glenrock, WY	Wind	2008	99	99
Seven Mile Hill	Medicine Bow, WY	Wind	2008	99	99
Goodnoe Hills	Goldendale, WA	Wind	2008	94	94
Marengo II	Dayton, WA	Wind	2008	70	70
Foot Creek	Arlington, WY	Wind	1999	41	33
Glenrock III	Glenrock, WY	Wind	2009	39	39
McFadden Ridge I	McFadden, WY	Wind	2009	28	28
Seven Mile Hill II	Medicine Bow, WY	Wind	2008	20	20
				1,040	1,032
OTHER: ⁽²⁾					
Blundell	Milford, UT	Geothermal	1984, 2007	34	34
Camas Co-Gen	Camas, WA	Black liquor	1996	22	22
				56	56
Total available generating capacity				14,231	10,623

- (1) Facility net capacity represents (except for wind-powered generating facilities, which are nominal ratings) the total capability of a generating unit as demonstrated by actual operating or test experience less power generated and used for auxiliaries and other station uses, and is determined using average annual temperatures. A wind turbine generator's nominal rating is the manufacturer's contractually specified capability (in MW) under specified conditions. Net owned capacity indicates PacifiCorp's ownership of Facility Net Capacity.
- (2) All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards ("RPS") or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.
- (3) The license for these facilities is valid through May 2058.
- (4) The license for these facilities is valid through October 2038.
- (5) The license for these facilities was valid through February 2006, and they currently operate on annual licenses. Refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for an update regarding hydroelectric relicensing for the Klamath River system.
- (6) The license is valid through March 2024 for Cutler and through November 2033 for the Grace, Oneida and Soda hydroelectric generating facilities.
- (7) The license is valid through December 2018 for Prospect No. 3 and through March 2038 for the Prospect Nos. 1, 2 and 4 hydroelectric generating facilities.

The following table shows the percentages of PacifiCorp's total energy supplied by energy source for the years ended December 31:

	2010	2009	2008
Coal	62 %	63 %	65 %
Natural gas	12	12	12
Hydroelectric	5	5	5
Other ⁽¹⁾	5	4	2
Total energy generated	84	84	84
Energy purchased - short-term contracts and other	8	10	11
Energy purchased - long-term contracts	8	6	5
	100 %	100 %	100 %

- (1) All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with RPS or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Coal

PacifiCorp has interests in coal mines that support its coal-fired generating facilities. These mines supplied 29% of PacifiCorp's total coal requirements during the year ended December 31, 2010 and 31% in each of the years ended December 31, 2009 and 2008. The remaining coal requirements are acquired through long- and short-term third-party contracts. PacifiCorp's mines are located adjacent to certain of its coal-fired generating facilities, which significantly reduces overall transportation costs included in fuel expense. Most of PacifiCorp's coal reserves are held pursuant to leases from the federal government through the Bureau of Land Management and from certain states and private parties. The leases generally have multi-year terms that may be renewed or extended only with the consent of the lessor and require payment of rents and royalties. In addition, federal and state regulations require that comprehensive environmental protection and reclamation standards be met during the course of mining operations and upon completion of mining activities.

Coal reserve estimates are subject to adjustment as a result of the development of additional engineering and geological data, new mining technology and changes in regulation and economic factors affecting the utilization of such reserves. Recoverable coal reserves as of December 31, 2010, based on PacifiCorp's most recent engineering studies, were as follows (in millions):

Coal Mine	Location	Generating Facility Served	Mining Method	Recoverable Tons
Bridger	Rock Springs, WY	Jim Bridger	Surface	51 (1)
Bridger	Rock Springs, WY	Jim Bridger	Underground	43 (1)
Deer Creek	Huntington, UT	Huntington, Hunter and Carbon	Underground	35 (2)
Trapper	Craig, CO	Craig	Surface	46 (3)
				<u>175</u>

(1) These coal reserves are leased and mined by Bridger Coal Company, ("Bridger Coal") a joint venture between Pacific Minerals, Inc. ("PMI") and a subsidiary of Idaho Power Company. PMI, a wholly owned subsidiary of PacifiCorp, has a two-thirds interest in the joint venture. The amounts included above represent only PacifiCorp's two-thirds interest in the coal reserves.

(2) These coal reserves are leased by PacifiCorp and mined by a wholly owned subsidiary of PacifiCorp.

(3) These coal reserves are leased and mined by Trapper Mining, Inc., a Delaware non-stock corporation operated on a cooperative basis, in which PacifiCorp has an ownership interest of 21%. The amount included above represents only PacifiCorp's 21% interest in the coal reserves. PacifiCorp does not operate the Trapper Mine.

For surface mine operations, PacifiCorp removes the overburden with heavy earth-moving equipment, such as draglines and power shovels. Once exposed, PacifiCorp drills, fractures and systematically removes the coal using haul trucks or conveyors to transport the coal to the associated generating facility. PacifiCorp reclaims disturbed areas as part of its normal mining activities. After final coal removal, draglines, power shovels, excavators or loaders are used to backfill the remaining pits with the overburden removed at the beginning of the process. Once the overburden and topsoil have been replaced, vegetation and plant life are re-established, and other improvements are made that have local community and environmental benefits. Draglines are used at the Bridger surface mine and draglines with shovels and trucks are used at the Trapper surface mine.

For underground mine operations, a longwall is used as a mechanical shearer to extract coal from long rectangular blocks of medium to thick seams. In longwall mining, PacifiCorp also uses continuous miners to develop access to these long rectangular coal blocks. Hydraulically powered supports temporarily hold up the roof of the mine while a rotating drum mechanically advances across the face of the coal seam, cutting the coal from the face. Chain conveyors then move the loosened coal to an underground mine conveyor system for delivery to the surface. Once coal is extracted from an area, the roof is allowed to collapse in a controlled fashion.

PacifiCorp operates the Deer Creek, Bridger surface and Bridger underground coal mines, as well as the Cottonwood Preparatory Plant and Wyodak Coal Crushing Facility. Refer to Item 9B of this Form 10-K for further information about the coal mines and coal processing facilities that PacifiCorp operates.

Recoverability by surface mining methods typically ranges from 90% to 95%. Recoverability by underground mining techniques ranges from 50% to 70%. To meet applicable standards, PacifiCorp blends coal mined at its owned mines with contracted coal and utilizes emissions reduction technologies for controlling sulfur dioxide and other emissions. For fuel needs at PacifiCorp's coal-fired generating facilities in excess of coal reserves available, PacifiCorp believes it will be able to purchase coal under both long- and short-term contracts to supply its generating facilities with coal over their currently expected remaining useful lives.

During the year ended December 31, 2010, PacifiCorp-owned coal-fired generating facilities held sufficient sulfur dioxide emission allowances to comply with the United States Environmental Protection Agency ("EPA") Title IV requirements.

Natural Gas

PacifiCorp uses natural gas as fuel for its combined- and simple-cycle natural gas-fired generating facilities. Oil and natural gas are also used for igniter fuel and to fuel generation for transmission support and standby purposes. These sources are presently in adequate supply and available to meet PacifiCorp's needs.

PacifiCorp enters into forward natural gas purchases at fixed or floating market prices for physical delivery to fuel its natural gas-fired generating facilities. PacifiCorp utilizes swap contracts to mitigate its price risk and lock in the cost of its forecasted fuel requirements. PacifiCorp also purchases natural gas in the spot market for physical delivery to fulfill any fuel requirements not already satisfied through forward purchases of natural gas and sells natural gas in the spot market for the disposition of any excess supply if the forecasted requirements of its natural gas-fired generating facilities decrease.

Hydroelectric

The amount of electricity PacifiCorp is able to generate from its hydroelectric facilities depends on a number of factors, including snowpack in the mountains upstream of its hydroelectric facilities, reservoir storage, precipitation in its watersheds, generating unit availability and restrictions imposed by oversight bodies due to competing water management objectives.

PacifiCorp operates the majority of its hydroelectric generating portfolio under long-term licenses from the Federal Energy Regulatory Commission ("FERC") with terms of 30 to 50 years, while some are licensed under the Oregon Hydroelectric Act. For further discussion of PacifiCorp's hydroelectric relicensing and decommissioning activities, including updated information regarding the Klamath hydroelectric system, refer to "Hydroelectric Relicensing" and "Hydroelectric Decommissioning" below and Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Wind and Other Renewable Resources

PacifiCorp has pursued additional renewable resources as a viable, economical and environmentally prudent means of supplying electricity. Renewable resources have low to no emissions, require little or no fossil fuel and are complemented by PacifiCorp's other generating facilities and wholesale transactions. PacifiCorp's wind-powered generating facilities placed in service by December 31, 2012 are eligible for federal renewable electricity production tax credits for 10 years from the date the facilities were placed in service.

Wholesale Activities

PacifiCorp purchases and sells electricity in the wholesale markets as needed to balance its generation and long-term purchase commitments with its retail load and long-term wholesale sales obligations. PacifiCorp may also purchase electricity in the wholesale markets when it is more economical than generating electricity from its own facilities. PacifiCorp utilizes both swaps and fixed-price electricity purchase contracts to reduce its exposure to electricity price volatility.

Transmission and Distribution

PacifiCorp operates one balancing authority area in the western portion of its service territory and one balancing authority area in the eastern portion of its service territory. A balancing authority area is a geographic area with transmission systems that control generation to maintain schedules with other balancing authority areas and ensure reliable operations. In operating the balancing authority areas, PacifiCorp is responsible for continuously balancing electricity supply and demand by dispatching generating resources and interchange transactions so that generation internal to the balancing authority area, plus net imported power, matches customer loads. PacifiCorp also schedules deliveries of energy over its transmission system in accordance with FERC requirements.

PacifiCorp's transmission system is part of the Western Interconnection, the regional grid in the western United States. The Western Interconnection includes the interconnected transmission systems of 14 western states, two Canadian provinces and parts of Mexico that make up the Western Electricity Coordinating Council ("WECC"). The map under "Service Territories" above shows PacifiCorp's primary transmission system.

As of December 31, 2010, PacifiCorp owned, or participated in, a transmission system consisting of approximately:

Nominal Voltage (in kilovolts)	Miles⁽¹⁾
Transmission Lines	
500	700
345	2,400
230	3,300
161	300
138	2,200
46 to 115	7,300
	<u>16,200</u>

(1) Includes PacifiCorp's share of jointly owned lines.

PacifiCorp's transmission and distribution system included approximately 900 substations as of December 31, 2010. PacifiCorp's transmission system, together with contractual rights on other transmission systems, enables PacifiCorp to integrate and access generation resources to meet its customer load requirements.

PacifiCorp's Energy Gateway Transmission Expansion Program represents plans to build approximately 2,000 miles of new high-voltage transmission lines, with an estimated cost exceeding \$6 billion, primarily in Wyoming, Utah, Idaho and Oregon. The plan includes several transmission line segments that will: (a) address customer load growth; (b) improve system reliability; (c) reduce transmission system constraints; (d) provide access to diverse generation resources, including renewable resources; and (e) improve the flow of electricity throughout PacifiCorp's six-state service area. Proposed transmission line segments are re-evaluated to ensure optimal benefits and timing before committing to move forward with permitting and construction. The Populus to Terminal transmission line, the first major transmission segment associated with this plan, was substantially completed in the fourth quarter of 2010. Other segments are expected to be placed in service through 2019, depending on siting, permitting and construction schedules.

Substantially all of PacifiCorp's generating facilities are managed on a coordinated basis to obtain maximum load-carrying capability and efficiency. Portions of PacifiCorp's transmission and distribution systems are located:

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

It is possible that some of the easements and the property over which the easements were granted may have title defects or may be subject to mortgages or liens existing at the time the easements were acquired.

Future Generation and Conservation

Integrated Resource Plan

As required by certain state regulations, PacifiCorp uses an Integrated Resource Plan ("IRP") to develop a long-term view of prudent future actions required to help ensure that PacifiCorp continues to provide reliable and cost-effective electric service to its customers. The IRP process identifies the amount and timing of PacifiCorp's expected future resource needs and an associated optimal future resource mix that accounts for planning uncertainty, risks, reliability impacts, state energy policies and other factors. The IRP is a coordinated effort with stakeholders in each of the six states where PacifiCorp operates. PacifiCorp files its IRP on a biennial basis and receives a formal notification in four states as to whether the IRP meets the commission's IRP standards and guidelines. In May 2009, PacifiCorp filed its 2008 IRP with each of its state commissions. During 2009, PacifiCorp received orders from the WUTC and the Idaho Public Utilities Commission ("IPUC") acknowledging that the 2008 IRP met their applicable standards and guidelines. During 2010, the Oregon Public Utility Commission ("OPUC") and the Utah Public Service Commission ("UPSC") issued orders acknowledging the 2008 IRP.

Requests for Proposals

PacifiCorp has issued a series of individual Requests for Proposals ("RFPs"), each of which focuses on a specific category of electric generation resources consistent with the IRP. The IRP and the RFPs provide for the identification and staged procurement of resources in future years to achieve a balance of load requirements and resources. As required by applicable laws and regulations, PacifiCorp files draft RFPs with the UPSC, the OPUC and the Washington Utilities and Transportation Commission ("WUTC") prior to issuance to the market. Approval by the UPSC, the OPUC or the WUTC may be required depending on the nature of the RFPs.

In August 2009, under PacifiCorp's 2008R-1 renewable resources RFP (approved by the OPUC in September 2008), PacifiCorp executed a power purchase agreement to purchase the entire output of the 200-MW Top of the World wind-powered generating facility located in Wyoming and the associated renewable energy credits. The generating facility reached commercial operation in October 2010, and the power purchase agreement will continue for a period of 20 years. PacifiCorp's 2009R renewable resources RFP (approved by the OPUC with modification in July 2009) seeks additional cost-effective renewable generation projects with no single resource greater than 300 MW, combined total resources of no more than 400 MW and on-line dates no later than December 31, 2012. As a result of the 2009R renewable resources RFP, PacifiCorp's 111-MW Dunlap Ranch I wind-powered generating facility located in Wyoming was constructed and placed in service in October 2010.

In October 2009, PacifiCorp filed a request for approval with the UPSC to re-issue the All Source RFP, which was previously suspended in April 2009. In October 2009 and November 2009, respectively, the UPSC and the OPUC approved resumption of the All Source RFP. The All Source RFP seeks up to 1,500 MW on a system wide basis from projects with in-service dates from 2014 through 2016. In December 2009, the All Source RFP was issued to the market. As a result, PacifiCorp signed an engineer, procure and construct contract, subject to regulatory approval, for the approximately 637-MW Lake Side 2 natural gas-fired combined-cycle generating facility. The Lake Side 2 generating facility will be constructed adjacent to PacifiCorp's Lake Side generating facility, which is located in Vineyard, Utah, about 40 miles south of Salt Lake City. PacifiCorp expects that the UPSC will issue an order approving the construction of Lake Side 2 by May 2011.

Demand-side Management

PacifiCorp has provided a comprehensive set of demand-side management ("DSM") programs to its customers since the 1970s. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. Current programs offer services to customers such as energy engineering audits and information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, PacifiCorp offers rebates or incentives encouraging the purchase and installation of high-efficiency equipment such as lighting, heating and cooling equipment, weatherization, motors, process equipment and systems, as well as incentives for efficient construction. Incentives are also paid to solicit participation in load management programs by residential, business and agricultural customers through programs, such as PacifiCorp's residential and small commercial air conditioner load control program and irrigation equipment load control programs. Although subject to prudence reviews, state regulations allow for contemporaneous recovery of costs incurred for the DSM programs through state-specific energy efficiency surcharges to retail customers or for recovery of costs through rates. In addition to these DSM programs, PacifiCorp has load curtailment contracts with a number of large industrial customers that deliver up to 305 MW of load reduction when needed. Recovery for the costs associated with the large industrial load management program is determined through PacifiCorp's general rate case process. During 2010, \$113 million was expended on PacifiCorp's DSM programs, resulting in an estimated 499,054 megawatt hours ("MWh") of first-year energy savings and an estimated 481 MW of peak load management. Total demand-side load available for control during 2010, including both load management from the large industrial curtailment contracts and DSM programs, was 718 MW.

General Regulation

PacifiCorp is subject to comprehensive governmental regulation, which significantly influences its operating environment, prices charged to customers, capital structure, costs and ability to recover costs. In addition to the following discussion, refer to "Liquidity and Capital Resources" in Item 7 and Note 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

State Regulation

PacifiCorp pursues a regulatory program in all states, with the objective of keeping rates closely aligned to ongoing costs. Historically, state regulatory commissions have established rates on a cost-of-service basis, which are designed to allow a utility an opportunity to recover its costs of providing services and to earn a reasonable return on its investments. A utility's cost of service generally reflects its allowed operating expenses, including energy costs, operation and maintenance expense, depreciation expense and income and other tax expense, reduced by wholesale electricity sales and other revenue. The allowed operating expenses are typically based on estimates of normalized costs, which may differ from realized costs in a given year covered by the established rates. State regulatory commissions may adjust rates pursuant to a review of (a) the utility's revenue and expenses during a defined test period and (b) the utility's level of investment. State regulatory commissions typically have the authority to review and change rates on their own initiative; however, they may also initiate reviews at the request of a utility, utility customer, a governmental agency or a representative of a group of customers. The utility and such parties, however, may agree with one another not to request a review of or changes to rates for a specified period of time.

PacifiCorp's retail rates are generally based on the cost of providing traditional bundled services, including generation, transmission and distribution services. Historically, the state regulatory framework in PacifiCorp's service areas reflect specified net power costs as part of bundled retail rates or incorporated net power cost adjustment clauses in PacifiCorp's retail rates and tariffs. In states where net power cost adjustment clauses exist, permitted periodic adjustments to cost recovery from customers provide protection to PacifiCorp against exposure to changes in net power costs.

Except for Oregon and Washington, PacifiCorp has an exclusive right to serve customers within its service territories, and in turn, has the obligation to provide electric service to those customers within its allocated service territory. Under Oregon law, PacifiCorp has the exclusive right and obligation to provide electric distribution services to all customers within its allocated service territory; however, nonresidential customers have the right to choose alternative electricity service suppliers. The impact of these programs on PacifiCorp's consolidated financial results has not been material. In Washington, state law does not provide for exclusive service territory allocation. PacifiCorp's service territory in Washington is surrounded by other public utilities with whom PacifiCorp has from time to time entered into service area agreements under the jurisdiction of the WUTC.

In addition to recovery through rates, PacifiCorp also achieves recovery of certain costs through various adjustment mechanisms as summarized below.

State Regulator	Base Rate Test Period	Adjustment Mechanism
Utah Public Service Commission	Forecasted or historical with known and measurable changes ⁽¹⁾	<p>PacifiCorp has requested approval of an energy cost adjustment mechanism ("ECAM") to recover the difference between base net power costs set during a general rate case and actual net power costs.</p> <p>A recovery mechanism is available for a single capital investment project that in total exceeds 1% of existing rate base when a general rate case has occurred within the preceding 18 months.</p>
Oregon Public Utility Commission	Forecasted	<p>Annual transition adjustment mechanism ("TAM") based on forecasted net variable power costs; no true-up to actual net variable power costs.</p> <p>Renewable adjustment clause ("RAC") to recover the revenue requirement of new renewable resources and associated transmission that are not reflected in general rates.</p> <p>Annual true-up of taxes authorized to be collected in rates compared to taxes paid by PacifiCorp, as defined by Oregon statute and administrative rules under Oregon Senate Bill 408 ("SB 408").</p>
Wyoming Public Service Commission ("WPSC")	Forecasted or historical with known and measurable changes ⁽¹⁾	ECAM under which 70% of any difference between actual and forecasted net power costs established in a general rate case would be subject to the ECAM mechanism between general rate cases.
Washington Utilities and Transportation Commission	Historical with known and measurable changes	Deferral mechanism of costs for up to 24 months of new base load generation resources and eligible renewable resources and related transmission that qualify under the state's emissions performance standard and are not reflected in general rates.
Idaho Public Utilities Commission	Historical with known and measurable changes	ECAM to recover the difference between base net power costs set during a general rate case and actual net power costs, subject to customer sharing and other adjustments.
California Public Utilities Commission ("CPUC")	Forecasted	<p>Post test-year adjustment mechanism for major capital additions ("PTAM - capital additions") that allows for rate adjustments outside of the context of a traditional general rate case for the revenue requirement associated with capital additions exceeding \$50 million on a total-company basis. Filed as eligible capital additions are placed into service.</p> <p>Energy cost adjustment clause ("ECAC") that allows for an annual update to actual and forecasted net variable power costs.</p> <p>Post test-year adjustment mechanism for attrition ("PTAM - attrition"), a mechanism that allows for an annual adjustment to costs other than net variable power costs.</p>

(1) PacifiCorp has relied on both historical test periods with known and measurable adjustments, as well as forecasted test periods.

PacifiCorp's DSM program costs are collected through separately established rates that are adjusted periodically based on actual and expected costs, as approved by the respective state regulatory commission. As such, recovery of DSM program costs has no impact on net income.

Federal Regulation

The FERC is an independent agency with broad authority to implement provisions of the Federal Power Act, the Energy Policy Act of 2005 ("Energy Policy Act") and other federal statutes. The FERC regulates rates for wholesale sales of electricity; transmission of electricity, including pricing and regional planning for the expansion of transmission systems; electric system reliability; utility holding companies; accounting; securities issuances; and other matters, including construction and operation of hydroelectric facilities. The FERC also has the enforcement authority to assess civil penalties of up to \$1 million per day per violation of rules, regulations and orders issued under the Federal Power Act. PacifiCorp has implemented programs that facilitate compliance with the FERC regulations described below, including having instituted compliance monitoring procedures.

Wholesale Electricity and Capacity

The FERC regulates PacifiCorp's rates charged to wholesale customers for electricity and transmission capacity and related services. Most of PacifiCorp's wholesale electricity sales and purchases take place under market-based pricing allowed by the FERC and are therefore subject to market volatility.

The FERC conducts triennial reviews of PacifiCorp's market-based pricing authority. PacifiCorp must demonstrate the lack of market power in order to charge market-based rates for sales of wholesale electricity and electric generation capacity in its market areas. PacifiCorp's most recent triennial filing was made in June 2010 and is currently pending before the FERC, while its next triennial filing is due in June 2013. Under the FERC's market-based rules, PacifiCorp must also file a notice of change in status when there is a significant change in the conditions that the FERC relied upon in granting market-based pricing authority. PacifiCorp is currently authorized to sell electricity on the wholesale market at market-based rates.

Transmission

PacifiCorp's wholesale transmission services are regulated by the FERC under cost-based regulation subject to PacifiCorp's Open Access Transmission Tariff ("OATT"). In accordance with its OATT, PacifiCorp offers several transmission services to wholesale customers:

- Network transmission service (service that integrates generating resources to serve retail loads);
- Long- and short-term firm point-to-point transmission service (service with fixed delivery and receipt points); and
- Non-firm point-to-point service (service with fixed delivery and receipt points on an as available basis).

These services are offered on a non-discriminatory basis, which means that all potential customers are provided an equal opportunity to access the transmission system. PacifiCorp's transmission business is managed and operated independently from its commercial and trading business, in accordance with the FERC rules. PacifiCorp has made several required compliance filings in accordance with these rules.

FERC Reliability Standards

The FERC has approved an extensive number of reliability standards developed by the North American Electric Reliability Corporation ("NERC") and the WECC, including critical infrastructure protection standards and regional standard variations. PacifiCorp must comply with all applicable standards. Compliance, enforcement and monitoring oversight of these standards is carried out by the FERC, the NERC and the WECC. In 2007, the WECC audited PacifiCorp's compliance with several of the approved reliability standards, and in November 2008, the FERC assumed control of certain aspects of the WECC's audit. In May 2009, PacifiCorp received a notice of alleged violation and proposed sanctions related to the portions of the WECC's 2007 audit that remained with the WECC. In July 2009, PacifiCorp reached a settlement with the WECC. The results of the settlement did not have a material impact on PacifiCorp's consolidated financial results. Refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding certain aspects of the WECC's 2007 audit currently under the FERC's authority and the FERC's reliability standards review.

Hydroelectric Relicensing

PacifiCorp's Klamath hydroelectric system is the only significant hydroelectric generating facility for which PacifiCorp is engaged in the relicensing process with the FERC. PacifiCorp also has requested the FERC to allow decommissioning of certain hydroelectric systems. Most of PacifiCorp's hydroelectric generating facilities are licensed by the FERC as major systems under the Federal Power Act, and certain of these systems are licensed under the Oregon Hydroelectric Act. Refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for an update regarding hydroelectric relicensing for PacifiCorp's Klamath hydroelectric system.

Hydroelectric Decommissioning

Powerdale Hydroelectric Facility - Hood River, Oregon

In June 2003, PacifiCorp entered into a settlement agreement to decommission the 6-MW Powerdale hydroelectric facility rather than pursue a new license, based on an analysis of the costs and benefits of relicensing versus decommissioning. In 2007, the FERC authorized PacifiCorp to cease generation at the facility and approved PacifiCorp's proposed accounting entries to defer the remaining net book value and any additional removal costs of the system as a regulatory asset. PacifiCorp received approval from its state regulatory commissions to defer and recover these costs. In April 2010, PacifiCorp initiated removal of the Powerdale dam and associated system features as stipulated in the FERC Surrender Order. As of October 31, 2010, decommissioning activities, including dam removal and site restoration, were completed. PacifiCorp will monitor restored areas until early 2012 when the project land is expected to be transferred to the Columbia Land Trust, Oregon Department of Fish and Wildlife and Hood River County. Removal costs for the Powerdale dam and associated system features were approximately \$4 million, and additional monitoring costs are not expected to exceed \$1 million.

Condit Hydroelectric Facility - White Salmon River, Washington

In September 1999, a settlement agreement to remove the 14-MW Condit hydroelectric facility was signed by PacifiCorp, state and federal agencies and non-governmental organizations. In early February 2005, the parties agreed to modify the settlement agreement, establishing a total cost to decommission not to exceed \$21 million, excluding inflation. In October 2010, the Washington Department of Ecology issued a Clean Water Act 401 certificate, and in December 2010, the FERC issued a surrender order. In January 2011, PacifiCorp filed a request for clarification and rehearing and motion for stay with the FERC. Remaining permitting includes a Section 404 permit from the United States Army Corps of Engineers. Decommissioning is expected to begin no earlier than October 2011.

Northwest Refund Case

For a discussion of the Northwest Refund case, refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

United States Mine Safety

PacifiCorp's mining operations are regulated by the federal Mine Safety and Health Administration ("MSHA"), which administers federal mine safety and health laws and regulations, and state regulatory agencies. MSHA has the statutory authority to institute a civil action for relief, including a temporary or permanent injunction, restraining order or other appropriate order against a mine operator who fails to pay penalties or fines for violations of federal mine safety standards. Federal law requires PacifiCorp to have a written emergency response plan specific to each underground mine it operates, which is reviewed by MSHA every six months, and to have at least two rescue teams located within one hour of each mine. Refer to Item 9B of this Form 10-K for further information regarding the coal mine and coal processing facilities that PacifiCorp operates.

Environmental Laws and Regulations

PacifiCorp is subject to federal, state and local laws and regulations regarding air and water quality, renewable portfolio standards, emissions performance standards, climate change, coal combustion byproducts, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact PacifiCorp's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by the EPA and various other state and local agencies. All such laws and regulations are subject to a range of interpretation, which may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and PacifiCorp is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. PacifiCorp believes it is in material compliance with all applicable laws and regulations.

Refer to "Liquidity and Capital Resources" in Item 7 of this Form 10-K for additional information regarding environmental laws and regulations and PacifiCorp's forecasted environmental-related capital expenditures.

Item 1A. Risk Factors

We are subject to certain risks and uncertainties in our business operations, including, but not limited to, those described below. Careful consideration of these risks, together with all of the other information included in this Form 10-K and the other public information filed by us, should be made before making an investment decision. Additional risks and uncertainties not presently known or that are currently deemed immaterial may also impair our business operations.

Our Corporate and Financial Structure Risks

We have a substantial amount of debt, which could adversely affect our consolidated financial results.

As of December 31, 2010, we had \$6.380 billion in total debt securities outstanding. Our principal financing agreements contain restrictive covenants that limit our ability to borrow funds, and any issuance of debt securities requires prior authorization from certain of our state regulatory commissions. We expect that we may need to supplement cash generated from operations and availability under committed credit facilities with new issuances of long-term debt. However, if market conditions are not favorable for the issuance of long-term debt, or if an issuance of long-term debt would exceed contractual or regulatory limits, we may postpone planned capital expenditures, or take other actions, to the extent those expenditures are not fully covered by cash from operations, borrowings under committed credit facilities or equity contributions from MEHC.

A downgrade in our credit ratings could negatively affect our access to capital, increase the cost of borrowing or raise energy transaction credit support requirements.

Our long-term debt and preferred stock are rated investment grade by various rating agencies. We cannot assure that our long-term debt and preferred stock will continue to be rated investment grade in the future. Although none of our outstanding debt has rating-downgrade triggers that would accelerate a repayment obligation, a credit rating downgrade would increase our borrowing costs and commitment fees on our revolving credit agreements and other financing arrangements, perhaps significantly. In addition, we would likely be required to pay a higher interest rate in future financings, and the potential pool of investors and funding sources would likely decrease. Further, access to the commercial paper market, the principal source of short-term borrowings, could be significantly limited, resulting in higher interest costs.

Most of our large wholesale customers, suppliers and counterparties require us to have sufficient creditworthiness in order to enter into transactions with them, particularly in the wholesale energy markets. If our credit ratings were to decline, especially below investment grade, financing costs and borrowings would likely increase because certain counterparties may require collateral in the form of cash, a letter of credit or some other security for existing transactions, as well as a condition to further transact with us. Such amounts may be material and may adversely affect our liquidity and cash flows.

MEHC could exercise control over us in a manner that would benefit MEHC to the detriment of our creditors and preferred stockholders.

MEHC, through its subsidiary, owns all of our common stock and has control over all decisions requiring shareholder approval, including the election of our directors. In circumstances involving a conflict of interest between MEHC and our creditors and preferred stockholders, MEHC could exercise its control in a manner that would benefit MEHC to the detriment of our creditors and preferred stockholders.

Our Business Risks

We are subject to extensive federal, state and local legislation and regulation, including numerous environmental, health, safety and other laws and regulations that affect our operations and costs. These laws and regulations are complex, dynamic and subject to new interpretations or change. In addition, new laws and regulations are continually being proposed and enacted that create new or revised requirements or standards on our business.

We are required to comply with numerous federal, state and local laws and regulations that have broad application to our business and limit our ability to independently make and implement management decisions regarding, among other items, business combinations; constructing, acquiring or disposing of operating assets; operation of generating facilities and transmission and distribution assets; setting rates charged to customers; establishing capital structures and issuing debt or equity securities; transactions with affiliates; and paying dividends. These laws and regulations are implemented and enforced by federal, state and local regulatory agencies, such as, among others, the FERC, the EPA, MSHA and the OPUC.

Significant examples of laws and regulations and other requirements affecting our present and future operations include, among others, those described below:

- Under authority granted to it in the Energy Policy Act, the FERC has approved regulations and issued decisions addressing electric system reliability; cyber security; critical infrastructure protection standards developed by the NERC; electric transmission planning, operation, expansion and pricing; regulation of utility holdings companies; and enforcement authority. The FERC has vigorously exercised its enhanced enforcement authority by imposing significant civil penalties for violations of its rules and regulations, which could be up to \$1 million per day per violation. These regulations have imposed, or will likely impose, more comprehensive and stringent requirements and increase our compliance costs, which could adversely affect our consolidated financial results.
- In July 2010, the President signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Reform Act"). The Dodd-Frank Reform Act reshapes financial regulation in the United States by creating new regulators, regulating new markets and firms and providing new enforcement powers to regulators. Virtually all major areas of the Dodd-Frank Reform Act, including collateral requirements on derivative contracts, will be the subject of regulatory interpretation and implementation rules requiring rulemaking proceedings that may take several years to complete. The outcome of the rulemaking proceedings cannot be predicted at this time; however, the impact of the Dodd-Frank Reform Act could have a material adverse effect on our consolidated financial results.
- The EPA's Clean Air Interstate Rule, which established cap-and-trade programs to reduce carbon dioxide and nitrogen oxides emissions starting in 2009 to address alleged contributions to downwind non-attainment with the revised National Ambient Air Quality Standards; federal and state renewable portfolio standards; and regulations that establish standards for air and water quality, wastewater discharges, solid waste, hazardous waste and coal combustion byproducts.
- Federal laws establishing underground coal mine safety, emergency preparedness and reporting, such as the Mine Improvement and New Emergency Response Act of 2006 ("MINER Act") and those laws administered by MSHA.
- Hydroelectric relicensing with the FERC is a public regulatory process involving sensitive resource issues and uncertainties. We cannot predict with certainty whether the outcome of our settlement agreement with relicensing stakeholders for our Klamath hydroelectric system will result in dam transfer and removal by a third party, nor can we predict the requirements (financial, operational or otherwise) that may be imposed by relicensing, the economic impact of those requirements, and whether new licenses will ultimately be issued or whether we will be willing to meet the relicensing requirements to continue operating our hydroelectric generating facilities. Loss of hydroelectric resources or additional commitments arising from relicensing could adversely affect our consolidated financial results.

Compliance with applicable laws and regulations generally requires us to obtain and comply with a wide variety of licenses, permits, inspections and other approvals. Further, compliance with laws and regulations can require significant capital and operating expenditures, including expenditures for new equipment, inspection, cleanup costs, damages arising out of contaminated properties and fines, penalties and injunctive measures affecting operating assets for failure to comply with environmental regulations. Compliance activities pursuant to laws and regulations could be prohibitively expensive. As a result, some facilities may be required to shut down or alter their operations. Further, we may not be able to obtain or maintain all required environmental regulatory approvals for our operating assets or development projects. Delays in or active opposition by third parties to obtaining any required environmental or regulatory permits, failure to comply with the terms and conditions of the permits or increased regulatory or environmental requirements may increase costs or prevent or delay us from operating our facilities, developing new facilities, expanding existing facilities or favorably locating new facilities. If we fail to comply with any environmental requirements, we may be subject to penalties and fines or other sanctions. The costs of complying with laws and regulations could adversely affect our consolidated financial results. Not being able to operate existing facilities or develop new generating facilities to meet customer electricity needs could require us to increase our purchases of electricity on the wholesale market, which could increase market and price risks and adversely affect our consolidated financial results.

Existing laws and regulations, while comprehensive, are subject to changes and revisions from ongoing policy initiatives by legislators and regulators and to interpretations that may ultimately be resolved by the courts. For example, changes in law and regulations could result in, but are not limited to, increased retail competition within our service territories; new environmental requirements, including the implementation of renewable portfolio standards and greenhouse gas ("GHG") emissions reduction goals; the issuance of stricter air quality standards and the implementation of energy efficiency mandates; the issuance of regulations over the management and disposal of coal combustion byproducts; the acquisition by a municipality of our distribution facilities; or a negative impact on our cost recovery arrangements.

In addition to changes in existing legislation and regulation, new laws and regulations are likely to be enacted that impose additional or new requirements or standards on our business. For example, the United States Congress and federal policy makers recently considered, but did not adopt, comprehensive climate change legislation. Adoption of new federal and state laws and regulations and changes in existing ones is emerging as one of the more challenging aspects of managing utility operations. We cannot predict the future course of new laws and regulations, changes in existing ones or new interpretations by agency orders or court decisions nor can their impact on us be determined at this time; however, any one of these could adversely affect our consolidated financial results through higher capital expenditures and operating costs and cause an overall change in how we operate our business. To the extent that we are not allowed by regulators to recover or cannot otherwise recover the costs to comply with new laws and regulations or changes in existing ones, the additional requirements could have a material adverse effect on our consolidated financial results. Additionally, even if such costs are recoverable in rates, if they are substantial and result in rates increasing to levels that substantially reduce customer demand, this could have a material adverse effect on our consolidated financial results.

Recovery of our costs is subject to regulatory review and approval, and the inability to recover costs may adversely affect our consolidated financial results.

State Rate Proceedings

Rates are established for our regulated retail service through state regulatory proceedings. These proceedings typically involve multiple parties, including government bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns, but who generally have the common objective of limiting rate increases. Decisions are subject to appeal, potentially leading to further uncertainty associated with the approval proceedings.

Each state sets retail rates based in part upon the state regulatory commission's acceptance of an allocated share of total utility costs. When states adopt different methods to calculate interjurisdictional cost allocations, some costs may not be incorporated into rates of any state. Ratemaking is also generally done on the basis of estimates of normalized costs, so if a given year's realized costs are higher than normalized costs, rates may not be sufficient to cover those costs. Each state regulatory commission generally sets rates based on a test year established in accordance with that commission's policies. The test year data adopted by each state regulatory commission may create a lag between the incurrence of a cost and its recovery in rates. Each state regulatory commission also decides the allowed levels of expense and investment that they deem are just and reasonable in providing the service and may disallow recovery in rates for any costs that do not meet such standard. State regulatory commissions also decide the allowed rate of return we will be given an opportunity to earn on our sources of capital.

In certain states, we are not permitted to pass through energy cost increases in our retail rates without a general rate case or are subject to deadbands and sharing mechanisms. Any significant increase in fuel costs for electricity generation or purchased electricity costs could have a negative impact on us, despite efforts to minimize this impact through future general rate cases or the use of hedging contracts. Any of these consequences could adversely affect our consolidated financial results.

While rate regulation is premised on providing a fair opportunity to obtain a reasonable rate of return on invested capital, the state regulatory commissions do not guarantee that we will be able to realize a reasonable rate of return.

FERC Jurisdiction

The FERC establishes cost-based rates under which we provide transmission services to wholesale markets and retail markets in states that allow retail competition. Under the Federal Power Act, we may voluntarily file, or may be obligated to file, for changes, including general rate changes, to our system-wide transmission service rates. The FERC also has responsibility for approving both cost- and market-based rates under which we sell electricity at wholesale, has licensing authority over most of our hydroelectric generating facilities and has broad jurisdiction over energy markets. The FERC may impose price limitations, bidding rules and other mechanisms to address some of the volatility of these markets or revoke or restrict our ability to sell electricity at market-based rates, which could adversely affect our consolidated financial results. The FERC may also impose substantial civil penalties for any non compliance with the Federal Power Act and the FERC's rules and orders.

We are actively pursuing, developing and constructing new or expanded facilities, the completion and expected cost of which are subject to significant risk, and we have significant funding needs related to our planned capital expenditures.

We are actively pursuing, developing and constructing new or expanded facilities. We expect that we will incur substantial annual capital expenditures over the next several years. Expenditures could include, among others, amounts for new electric generating facilities, electric transmission or distribution projects, environmental control and compliance systems, as well as the continued maintenance of existing assets.

Development and construction of major facilities are subject to substantial risks, including fluctuations in the price and availability of commodities, manufactured goods, equipment, labor and other items over a multi-year construction period, as well as the economic viability of our suppliers. These risks may result in higher than expected costs to complete an asset and place it in service. Such costs may not be recoverable in the rates or market prices we are able to charge our customers. It is also possible that additional generation needs may be obtained through power purchase agreements, which could increase long-term purchase obligations and force reliance on the operating performance of a third party. The inability to successfully and timely complete a project, avoid unexpected costs or to recover any such costs could adversely affect our consolidated financial results.

Furthermore, we depend upon both internal and external sources of liquidity to provide working capital and to fund capital requirements. If we are unable to obtain funding from internal and external sources, we may need to postpone or cancel planned capital expenditures.

Failure to construct our planned projects could limit opportunities for revenue growth, increase operating costs and adversely affect the reliability of electricity service to our customers. For example, if we are not able to expand our existing generating facilities, we may be required to enter into long-term wholesale electricity purchase contracts or purchase wholesale electricity at more volatile and potentially higher prices in the spot markets to support retail loads.

A sustained decrease in demand for electricity in the markets served by us would significantly decrease our operating revenue and adversely affect our consolidated financial results.

A sustained decrease in demand for electricity in the markets served by us would significantly reduce our operating revenue and adversely affect our consolidated financial results. Factors that could lead to a decrease in market demand include, among others:

- a depression, recession or other adverse economic condition that results in a lower level of economic activity or reduced spending by consumers on electricity, including the significant adverse changes in the economy and credit markets experienced in 2008 and 2009;
- an increase in the market price of electricity or a decrease in the price of other competing forms of energy;
- efforts by customers, legislators and regulators to reduce the consumption of energy through various conservation and energy efficiency measures and programs;
- higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of the fuel source for electricity generation or that limit the use of the generation of electricity from fossil fuels; and
- a shift to more energy-efficient or alternative fuel machinery or an improvement in fuel economy, whether as a result of technological advances by manufacturers, legislation mandating higher fuel economy or lower emissions, price differentials, incentives or otherwise.

We are subject to market risk associated with the wholesale energy markets, which could adversely affect our consolidated financial results.

In general, our primary market risk is the risk of adverse fluctuations in the market price of wholesale electricity and fuel, including natural gas, coal and fuel oil, which is compounded by volumetric changes affecting the availability of or demand for electricity and fuel. Wholesale electricity may be influenced by several factors, such as the adequacy of generating capacity; scheduled and unscheduled outages of generating facilities; prices and availability of fuel sources for generation; disruptions or constraints to transmission and distribution facilities; weather conditions; economic growth; and changes in technology. Volumetric changes are caused by unanticipated changes in generation availability or changes in customer needs that can be due to the weather, electricity and fuel prices, the economy, regulations or customer behavior. For example, we purchase electricity and fuel in the open market as part of our normal operating business. If market prices rise, especially in a time when larger than expected volumes must be purchased at market or short-term prices, we may incur significantly greater expense than anticipated. Likewise, if electricity market prices decline in a period when we are a net seller of electricity in the wholesale market, we will earn less revenue.

We are subject to counterparty credit risk, which could adversely affect our consolidated financial results.

We are subject to counterparty credit risk related to contractual obligations with wholesale suppliers and customers. Adverse economic conditions or other events affecting counterparties with whom we conduct business could impair the ability of these counterparties to timely pay for services. We depend on these counterparties to remit payments on a timely basis. For example, certain wholesale suppliers and customers experienced deteriorating credit quality in 2008 and 2009, and this trend continued, though on a limited basis, in 2010. If our wholesale customers are unable to pay us for energy, there may be a significant adverse impact on our consolidated financial results.

We continue to monitor the creditworthiness of wholesale suppliers and customers in an attempt to reduce the impact of any potential counterparty default. If strategies used to minimize these risk exposures are ineffective or if our wholesale customers' financial condition deteriorates as a result of economic conditions causing them to be unable to pay, significant losses could result.

We are subject to counterparty performance risk, which could adversely affect our consolidated financial results.

We are subject to counterparty performance risk related to performance of contractual obligations by wholesale suppliers and customers. We rely on wholesale suppliers to deliver commodities, primarily natural gas, coal and electricity, in accordance with short- and long-term contracts. Failure or delay by suppliers to provide these commodities pursuant to existing contracts could disrupt the delivery of electricity and require us to incur additional expenses to meet customer needs. In addition, when these contracts terminate, we may be unable to purchase the commodities on terms equivalent to the terms of current contracts.

We rely on wholesale customers to take delivery of the energy they have committed to purchase. Failure of customers to take delivery may require us to find other customers to take the energy at lower prices than the original customers committed to pay. At certain times of the year, prices paid by us for energy needed to satisfy our customers' energy needs may exceed the amount we receive through rates. If our wholesale customers are unable to fulfill their obligations, there may be a significant adverse impact on our consolidated financial results.

Disruptions in the financial markets could affect our ability to obtain debt financing, draw upon or renew existing credit facilities, and have other adverse effects on us.

During 2008 and early 2009, the United States and global credit markets experienced historic dislocations and liquidity disruptions that caused financing to be unavailable in many cases. These circumstances materially impacted liquidity in the bank and debt capital markets during this period, making financing terms less attractive for borrowers that were able to find financing, and in other cases resulted in the unavailability of certain types of debt financing. It is difficult to predict how the financial markets will react to the United States federal government's continued involvement or gradual withdrawal or removal of certain economic stimulus programs. Uncertainty in the credit markets may negatively impact our ability to access funds on favorable terms or at all. If we are unable to access the bank and debt markets to meet liquidity and capital expenditure needs, it may adversely affect the timing and amount of our capital expenditures and our consolidated financial results.

Inflation and changes in commodity prices and fuel transportation costs may adversely affect our consolidated financial results.

Inflation may affect our business by increasing both operating and capital costs. As a result of existing rate agreements and competitive price pressures, we may not be able to pass the costs of inflation on to our customers. If we are unable to manage cost increases or pass them on to our customers, our consolidated financial results could be adversely affected.

Our consolidated financial results may be adversely affected if we are unable to obtain adequate, reliable and affordable access to electricity transmission service and natural gas transportation.

We depend on electricity transmission and natural gas transportation facilities owned and operated by other companies to transport electricity to both wholesale and retail markets and to transport natural gas purchased to supply some of our generating facilities. If adequate transmission and transportation is unavailable, we may be unable to purchase and sell and deliver electricity. A lack of availability could also hinder us from providing adequate or cost-effective electricity to our wholesale and retail customers and could adversely affect our consolidated financial results.

The different regional power markets have varying and dynamic regulatory structures, which could affect our growth and performance. In addition, the independent system operators who oversee the transmission systems in certain portions of the regional power markets in which we transact have imposed in the past, and may impose in the future, price limitations and other mechanisms to counter volatility in the power markets. These types of price limitations and other mechanisms may adversely affect our consolidated financial results.

Our operating results may fluctuate on a seasonal and quarterly basis and may be adversely affected by weather.

In the markets in which we operate, demand for electricity peaks during the hot summer months when irrigation and cooling needs are higher. Market prices for electricity also generally peak at that time. In addition, demand for electricity generally peaks during the winter when heating needs are higher. Further, extreme weather conditions, such as heat waves, winter storms or floods could cause these seasonal fluctuations to be more pronounced. Periods of low rainfall or snowpack may impact electricity generation at our hydroelectric generating facilities, which may result in greater purchases of electricity from the wholesale market or from other sources at market prices. Additionally, we have added substantial wind-powered generation capacity, which is also a climate-dependent resource.

As a result, our overall consolidated financial results may fluctuate substantially on a seasonal and quarterly basis. We have historically sold less energy, and consequently earned less income, when weather conditions are mild. Unusually mild weather in the future may adversely affect our consolidated financial results through lower revenue or margins. Conversely, unusually extreme weather conditions could increase our costs to provide energy and could adversely affect our consolidated financial results. The extent of fluctuation in our consolidated financial results may change depending on a number of factors related to our regulatory environment and contractual agreements, including our ability to recover energy costs and terms of the wholesale sale contracts.

We are subject to operating uncertainties that could adversely affect our consolidated financial results.

The operation of complex electric utility (including generation, transmission and distribution) systems that are spread over large geographic areas involves many operating uncertainties and events beyond our control. These potential events include the breakdown or failure of electricity generating equipment, transmission and distribution lines or other equipment or processes; unscheduled generating facility outages; strikes, lockouts or other labor-related actions; shortage of qualified labor; transmission and distribution system constraints or outages; fuel shortages or interruptions; unavailability of critical equipment, materials and supplies; low water flows and other weather-related impacts; performance below expected levels of output, capacity or efficiency; operator error and catastrophic events such as severe storms, fires, earthquakes, explosions or mining accidents. A casualty occurrence might result in injury or loss of life, extensive property damage or environmental damage. Any of these risks or other operational risks could significantly reduce or eliminate our revenue or significantly increase our expenses. For example, if we cannot operate our generating facilities at full capacity due to damage caused by a catastrophic event, our revenue could decrease and our expenses could increase due to the need to obtain energy from more expensive sources. Further, we self-insure many risks, and current and future insurance coverage may not be sufficient to replace lost revenue or cover repair and replacement costs and the scope, cost and availability of our insurance coverage may change, including the portion that is self-insured. Any reduction of our revenue or increase in our expenses resulting from the risks described above, could adversely affect our consolidated financial results.

Potential terrorist activities or military or other actions could adversely affect our consolidated financial results.

The ongoing threat of terrorism and the impact of military and other actions by the United States and its allies creates increased political, economic and financial market instability, which subjects our operations to increased risks. The United States government has issued warnings that energy assets, specifically including electric utility infrastructure, are potential targets for terrorist organizations. Political, economic or financial market instability or damage to our operating assets or the assets of our customers or suppliers may result in business interruptions, lost revenue, higher commodity prices, disruption in fuel supplies, lower energy consumption and unstable markets, particularly with respect to electricity and natural gas, increased security, repair or other costs that may materially adversely affect us in ways that cannot be predicted at this time. Any of these risks could materially affect our consolidated financial results. Furthermore, instability in the financial markets as a result of terrorism or war could also materially adversely affect our ability to raise capital.

Poor performance of plan and fund investments and other factors impacting our pension and other postretirement benefit plans, the joint trust plans to which we contribute and mine reclamation trust funds could unfavorably impact our cash flows and liquidity.

Costs of providing our defined benefit pension and other postretirement benefit plans, as well as costs associated with the joint trust plans to which we contribute, depend upon a number of factors, including the rates of return on plan assets, the level and nature of benefits provided, discount rates, the interest rates used to measure required minimum funding levels, changes in benefit design, changes in laws and government regulation and our required or voluntary contributions made to the plans. Our pension and other postretirement benefit plans, as well as certain joint trust plans to which we contribute, are in underfunded positions. Even with sustained growth in the investments over future periods to increase the value of these plans' assets, we will likely be required to make significant cash contributions to fund these plans in the future. Furthermore, the Pension Protection Act of 2006, as amended, may result in more volatility in the amount and timing of future contributions. Similarly, funds dedicated to mine reclamation are invested in equity and fixed-income securities and poor performance of these investments will reduce the amount of funds available for their intended purpose which would require us to make additional cash contributions. Such cash funding obligations, which are also impacted by the other factors described above, could have a material impact on our liquidity by reducing our cash flows.

We are involved in numerous legal proceedings, the outcomes of which are uncertain and could adversely affect our consolidated financial results.

We are party to numerous legal proceedings. Litigation is subject to many uncertainties, and we cannot predict the outcome of individual matters. It is possible that the final resolution of some of the matters in which we are involved could result in additional payments in excess of established reserves over an extended period of time and in amounts that could have a material adverse effect on our consolidated financial results. Similarly, it is also possible that the terms of resolution could require that we change business practices and procedures, which could also have a material adverse effect on our consolidated financial results. Further, litigation could result in the imposition of financial penalties or injunctions which could limit our ability to take certain desired actions or the denial of needed permits, licenses or regulatory authority to conduct our business, including the siting or permitting of facilities. Any of these outcomes could adversely affect our consolidated financial results.

Potential changes in accounting standards may impact our consolidated financial results and disclosures in the future, which may change the way analysts measure our business or financial performance.

The Financial Accounting Standards Board ("FASB") and the SEC continuously make changes to accounting standards and disclosure and other financial reporting requirements. New or revised accounting standards and requirements issued by the FASB or the SEC or new accounting orders issued by the FERC could significantly impact our consolidated financial results and disclosures.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

PacifiCorp's properties consist of the physical assets necessary to support its electricity business, which include electric generation, transmission and distribution facilities, as well as coal mining assets that support certain of PacifiCorp's electric generating facilities. In addition to these physical assets, PacifiCorp has rights-of-way, mineral rights and water rights that enable PacifiCorp to utilize its facilities. It is the opinion of PacifiCorp's management that the principal depreciable properties owned by PacifiCorp are in good operating condition and are well maintained. Substantially all of PacifiCorp's electric utility properties are subject to the lien of PacifiCorp's Mortgage and Deed of Trust. Refer to Exhibit 4.1 in Item 15 of this Form 10-K. For additional information regarding PacifiCorp's properties, refer to Item 1 of this Form 10-K and Notes 3 and 4 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

The right to construct and operate PacifiCorp's electric transmission and distribution facilities across certain property was obtained in most circumstances through negotiations and, where necessary, through the exercise of the power of eminent domain. PacifiCorp continues to have the power of eminent domain in each of the jurisdictions in which it operates, but it does not have the power of eminent domain with respect to Native American tribal lands.

With respect to real property, each of the transmission and distribution facilities fall into two basic categories: (a) parcels that are owned in fee, such as certain of PacifiCorp's generating facilities, substations and office sites; and (b) parcels where the interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for the construction, operation and maintenance of the transmission and distribution facilities. PacifiCorp believes that it has satisfactory title to all of the real property making up its respective facilities in all material respects.

Headquarters/Offices

PacifiCorp's corporate offices consist of approximately 800,000 square feet of owned and leased office space located in several buildings in Portland, Oregon and Salt Lake City, Utah. PacifiCorp's corporate headquarters are in Portland, but there are several executives and departments located in Salt Lake City. In addition to the corporate headquarters, PacifiCorp owns and leases approximately 1 million square feet of field office and warehouse space in various other locations in Utah, Oregon, Wyoming, Washington, Idaho and California. The field location square footage does not include offices located at PacifiCorp's generating facilities.

Item 3. Legal Proceedings

PacifiCorp is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. PacifiCorp does not believe that such normal and routine litigation will have a material impact on its consolidated financial results. PacifiCorp is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines, penalties and other costs in substantial amounts and are described below.

In December 2000, Wah Chang, a large industrial customer of PacifiCorp, filed an action before the OPUC asserting that the rates set by a special tariff with PacifiCorp and approved by the OPUC were not just and reasonable due to alleged market manipulation during the energy crisis. In October 2001, the OPUC dismissed Wah Chang's petition and found that Wah Chang assumed the risk of price increases under the special tariff. Wah Chang petitioned the Circuit Court for Marion County, Oregon for review of the OPUC's order. In June 2002, the Circuit Court for Marion County, Oregon, granted Wah Chang's motion for review, and ordered the OPUC to reopen the record to allow Wah Chang the opportunity to present new evidence. In September 2009, the OPUC dismissed Wah Chang's petition and reaffirmed that the rates set by the special tariff were just and reasonable. In October 2009, Wah Chang filed with the Oregon Court of Appeals a petition for judicial review of the OPUC's September 2009 order denying Wah Chang relief. In July 2010, the Oregon Court of Appeals accepted judicial review.

In a separate but related proceeding, in December 2000, Wah Chang filed a complaint in the Circuit Court for Linn County, Oregon, asserting that the OPUC-approved special tariff with PacifiCorp is subject to rescission based on theories of mutual mistake of fact, frustration of purpose and impracticability. In August 2002, the Circuit Court for Linn County, Oregon, granted PacifiCorp's motion for summary judgment dismissing Wah Chang's complaint. In February 2004, the Circuit Court for Linn County, Oregon, granted Wah Chang's motion to reopen the case to present additional evidence of alleged market manipulation. In December 2007, Wah Chang filed a second amended complaint seeking recovery of a portion of the costs paid under the special tariff based on various theories of legal relief, including partial rescission, unjust enrichment, and breach of duty of good faith and fair dealing. In August 2009, the Circuit Court for Linn County, Oregon, granted Wah Chang's request to file a third amended complaint containing a claim for punitive damages. The trial date has been set for April 2011. Wah Chang is seeking \$37 million (less the amount Wah Chang would have paid for electricity absent the special tariff) in compensatory damages and \$200 million in punitive damages. PacifiCorp intends to vigorously defend these claims and believes that the outcome of these proceedings will not have a material impact on its consolidated financial results.

In October 2005, PacifiCorp was added as a defendant to a lawsuit originally filed in February 2005 in the Third District Court for Salt Lake County, Utah ("Third District Court") by USA Power, LLC and its affiliated companies, USA Power Partners, LLC and Spring Canyon Energy, LLC (collectively, "USA Power"), against Utah attorney Jody L. Williams and the law firm Holme, Roberts & Owen, LLP, who represent PacifiCorp on various matters from time to time. USA Power was the developer of a planned generation project in Mona, Utah called Spring Canyon, which PacifiCorp, as part of its resource procurement process, at one time considered as an alternative to the Currant Creek generating facility. USA Power's complaint alleged that PacifiCorp misappropriated confidential proprietary information in violation of Utah's Uniform Trade Secrets Act and accused PacifiCorp of breach of contract and related claims. USA Power seeks \$250 million in damages, statutory doubling of damages for its trade secrets violation claim, punitive damages, costs and attorneys' fees. The statutory doubling of damages only applies to the plaintiffs' trade secret claim and could increase the total damages sought to \$500 million. After considering various motions for summary judgment, the court ruled in October 2007 in favor of PacifiCorp on all counts and dismissed the plaintiffs' claims in their entirety. In February 2008, the plaintiffs filed a petition requesting consideration by the Utah Supreme Court of two of their five claims. The plaintiffs' request was granted and they filed a brief in November 2008 with the Utah Supreme Court. In January 2009, PacifiCorp filed its reply brief. In May 2010, the Utah Supreme Court reversed and remanded the case back to the Third District Court for further consideration. The Third District Court set an eight-week trial for June and July 2011. PacifiCorp cannot predict the outcome of these proceedings, but believes that the outcome will not have a material impact on its consolidated financial results.

Item 4. (Removed and Reserved)

PART II

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

MEHC indirectly owns all of the shares of PacifiCorp's outstanding common stock. Therefore, there is no public market for PacifiCorp's common stock.

In January 2011, PacifiCorp declared a dividend of \$275 million payable to PPW Holdings LLC, a direct subsidiary of MEHC, on February 28, 2011. PacifiCorp did not declare or pay dividends on common stock during the years ended December 31, 2010 and 2009.

During the years ended December 31, 2010 and 2009, PacifiCorp received capital contributions of \$100 million and \$125 million, respectively, in cash from its indirect parent company, MEHC.

For a discussion of regulatory restrictions that limit PacifiCorp's ability to pay dividends on common stock, refer to "Limitations" in Item 7 and Note 15 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Item 6. Selected Financial Data

The following table sets forth PacifiCorp's selected consolidated historical financial data, which should be read in conjunction with Item 7 of this Form 10-K and with PacifiCorp's historical Consolidated Financial Statements and notes thereto in Item 8 of this Form 10-K. The selected consolidated historical financial data has been derived from PacifiCorp's audited historical Consolidated Financial Statements and notes thereto (in millions). In May 2006, the PacifiCorp Board of Directors elected to change PacifiCorp's fiscal year-end from March 31 to December 31.

	Years Ended December 31,				Nine-Month Period Ended December 31,
	2010	2009	2008	2007	2006
Consolidated Statement of Operations Data:					
Operating revenue	\$ 4,432	\$ 4,457	\$ 4,498	\$ 4,258	\$ 2,924
Operating income	1,036	1,060	954	894	421
Net income attributable to PacifiCorp	566	542	458	439	161
	As of December 31,				
	2010	2009	2008	2007	2006
Consolidated Balance Sheet Data:					
Total assets	\$ 20,146	\$ 18,966	\$ 17,167	\$ 14,907	\$ 13,852
Short-term debt	36	—	85	—	397
Current portion of long-term debt and capital lease obligations	588	16	144	414	127
Long-term debt and capital lease obligations, excluding current portion	5,813	6,400	5,424	4,753	3,967
Preferred stock	41	41	41	41	41
Total PacifiCorp shareholders' equity	7,311	6,648	5,987	5,080	4,426

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

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of PacifiCorp during the periods included herein. Explanations include management's best estimate of the impact of weather, customer growth and other factors. This discussion should be read in conjunction with Item 6 of this Form 10-K and with PacifiCorp's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. PacifiCorp's actual results in the future could differ significantly from the historical results.

Results of Operations

Overview

Net income attributable to PacifiCorp for the year ended December 31, 2010 was \$566 million, an increase of \$24 million, or 4%, as compared to 2009. Net income attributable to PacifiCorp increased due to higher prices approved by regulators, higher sales of renewable energy credits, higher benefits associated with deferred net power costs, higher allowances for funds used during construction and a lower effective tax rate, partially offset by lower net wholesale electricity activities, higher depreciation on higher plant placed in service and higher operations and maintenance expense.

Net income attributable to PacifiCorp for the year ended December 31, 2009 was \$542 million, an increase of \$84 million, or 18%, as compared to 2008. Net income attributable to PacifiCorp increased due to higher prices approved by regulators, higher net wholesale electricity activities and higher sales of renewable energy credits, partially offset by lower retail customer usage primarily due to the impacts of the economic conditions on industrial customers across PacifiCorp's service territories and residential customers in Oregon, higher depreciation on higher plant placed in service and higher interest expense due to the issuance of long-term debt to finance the higher plant.

Operating revenue and energy costs are the key drivers of PacifiCorp's results of operations as they encompass retail and wholesale electricity sales and the direct costs associated with providing electricity to customers. PacifiCorp believes that a discussion of gross margin, representing operating revenue less energy costs, is therefore useful.

As discussed in Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K, PacifiCorp adopted authoritative guidance as of January 1, 2010 that required the deconsolidation of its majority owned coal mining joint venture, Bridger Coal. As a result, Bridger Coal is being accounted for under the equity method on a prospective basis. The deconsolidation of Bridger Coal had no impact on net income attributable to PacifiCorp during the year ended December 31, 2010. Prior to the deconsolidation of Bridger Coal, PacifiCorp adopted authoritative guidance on January 1, 2009 that established accounting and reporting standards for the noncontrolling interest in a subsidiary. This guidance impacted PacifiCorp's presentation of both revenue and expense associated with the noncontrolling interest in Bridger Coal and had no impact on net income attributable to PacifiCorp during the years ended December 31, 2009 and 2008.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

A comparison of PacifiCorp's key operating results were as follows for the years ended December 31:

	2010	2009	Favorable/(Unfavorable)	
			Change	% Change
<u>Gross margin (in millions):</u>				
Operating revenue	\$ 4,432	\$ 4,457	\$ (25)	(1)%
Energy costs	1,618	1,677	59	4
Gross margin	<u>\$ 2,814</u>	<u>\$ 2,780</u>	<u>\$ 34</u>	<u>1 %</u>
<u>Volumes of electricity sold (in gigawatt hours ("GWh")):</u>				
Residential	15,795	15,999	(204)	(1)%
Commercial	15,969	16,194	(225)	(1)
Industrial	20,680	19,934	746	4
Other	572	583	(11)	(2)
Total retail electricity sales	<u>53,016</u>	<u>52,710</u>	<u>306</u>	<u>1</u>
Wholesale electricity sales	<u>11,415</u>	<u>12,349</u>	<u>(934)</u>	<u>(8)</u>
Total electricity sales	<u><u>64,431</u></u>	<u><u>65,059</u></u>	<u><u>(628)</u></u>	<u><u>(1)%</u></u>
<u>Retail electricity sales:</u>				
Average retail customers (in thousands)	1,733	1,719	14	1 %
Average revenue per MWh	\$ 70.01	\$ 67.68	\$ 2.33	3 %
<u>Wholesale electricity sales:</u>				
Average revenue per MWh	\$ 43.02	\$ 51.95	\$ (8.93)	(17)%
<u>Volumes of electricity generated (in GWh):</u>				
Coal-fired generation	42,612	43,854	(1,242)	(3)%
Natural gas-fired generation	8,416	8,576	(160)	(2)
Hydroelectric generation	3,744	3,544	200	6
Other	2,862	2,427	435	18
Total PacifiCorp generated volumes	<u>57,634</u>	<u>58,401</u>	<u>(767)</u>	<u>(1)%</u>
<u>Volumes of electricity purchased (in GWh):</u>				
Wholesale electricity purchases	11,329	10,975	(354)	(3)%
<u>Cost of wholesale electricity purchased:</u>				
Average cost per MWh	\$ 38.50	\$ 42.95	\$ 4.45	10 %

Gross margin increased \$34 million, or 1%, for 2010 compared to 2009 primarily due to:

- \$138 million of increases from higher retail prices approved by regulators primarily to recover increased costs of assets placed in service and higher energy costs, including \$40 million of increases in DSM revenue primarily associated with Utah and Oregon DSM programs and a \$10 million decrease in revenue associated with SB 408;
- \$43 million of increases from sales of renewable energy credits;
- \$39 million of increases from higher deferrals of incurred power costs and lower amortization of previous deferrals in accordance with established adjustment mechanisms;
- \$14 million of increases resulting from the elimination of certain regulatory liabilities in the current period resulting from the Utah DSM settlement and the Utah general rate case order; and
- \$6 million of decreases in fuel costs primarily due to lower average prices paid for natural gas and lower volumes of coal and natural gas consumed, substantially offset by increased coal prices.

The increase in gross margin was partially offset by:

- \$115 million of decreases resulting from net wholesale electricity activities due to \$102 million of lower average prices on wholesale electricity sales, \$49 million of lower volumes of wholesale electricity sales and \$15 million of higher volumes of wholesale electricity purchases, partially offset by \$51 million lower average prices on wholesale purchases;
- \$66 million of decreases from lower revenue related to the deconsolidation of Bridger Coal;
- \$18 million of decreases resulting from higher transmission expense due to higher contract rates; and
- \$8 million of decreases due to lower customer usage in the western side of PacifiCorp's service territory primarily due to unfavorable weather, partially offset by higher industrial customer usage and higher growth in the average number of customers in the eastern side of PacifiCorp's service territory.

Operations and maintenance increased \$46 million, or 4%, primarily due to higher Utah and Oregon DSM expenses, the write-off of a portion of the Utah DSM regulatory asset in the current period resulting from the Utah DSM settlement and the Utah general rate case order and higher costs associated with jointly owned generating facilities primarily due to increased overhauls, partially offset by lower costs related to the deconsolidation of Bridger Coal.

Depreciation and amortization increased \$12 million, or 2%, primarily due to higher plant placed in service, partially offset by revised depreciation rates in California and \$10 million of lower depreciation related to the deconsolidation of Bridger Coal.

Taxes, other than income taxes were consistent with the prior year, but included \$13 million of increased property taxes, substantially offset by decreases related to the deconsolidation of Bridger Coal.

Allowances for borrowed and equity funds increased \$25 million, or 25%, primarily due to higher qualified construction work-in-progress balances.

Interest income decreased \$14 million, or 74%, primarily due to interest recognized in the prior year associated with SB 408.

Income tax expense decreased \$23 million to \$211 million for 2010 compared to 2009, primarily due to the effects of ratemaking, higher production tax credits associated with PacifiCorp's wind-powered generating facilities and lower pre-tax income. The effective tax rate was 27% for the year ended December 31, 2010 compared to 30% for 2009.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

A comparison of PacifiCorp's key operating results were as follows for the years ended December 31:

	2009	2008	Favorable/(Unfavorable)	
			Change	% Change
<u>Gross margin (in millions):</u>				
Operating revenue	\$ 4,457	\$ 4,498	\$ (41)	(1)%
Energy costs	1,677	1,957	280	14
Gross margin	<u>\$ 2,780</u>	<u>\$ 2,541</u>	<u>\$ 239</u>	<u>9 %</u>
<u>Volumes of electricity sold (in GWh):</u>				
Residential	15,999	16,222	(223)	(1)%
Commercial	16,194	16,055	139	1
Industrial	19,934	21,495	(1,561)	(7)
Other	583	590	(7)	(1)
Total retail electricity sales	<u>52,710</u>	<u>54,362</u>	<u>(1,652)</u>	<u>(3)</u>
Wholesale electricity sales	<u>12,349</u>	<u>12,345</u>	<u>4</u>	<u>0</u>
Total electricity sales	<u><u>65,059</u></u>	<u><u>66,707</u></u>	<u><u>(1,648)</u></u>	<u><u>(2)%</u></u>
<u>Retail electricity sales:</u>				
Average retail customers (in thousands)	1,719	1,706	13	1 %
Average revenue per MWh	\$ 67.68	\$ 64.12	\$ 3.56	6 %
<u>Wholesale electricity sales:</u>				
Average revenue per MWh	\$ 51.95	\$ 68.78	\$ (16.83)	(24)%
<u>Volumes of electricity generated (in GWh):</u>				
Coal-fired generation	43,854	45,955	(2,101)	(5)%
Natural gas-fired generation	8,576	8,771	(195)	(2)
Hydroelectric generation	3,544	3,766	(222)	(6)
Other	2,427	1,386	1,041	75
Total PacifiCorp generated volumes	<u>58,401</u>	<u>59,878</u>	<u>(1,477)</u>	<u>(2)%</u>
<u>Volumes of electricity purchased (in GWh):</u>				
Wholesale electricity purchases	10,975	11,448	473	4 %
<u>Cost of wholesale electricity purchased:</u>				
Average cost per MWh	\$ 42.95	\$ 66.56	\$ 23.61	35 %

Gross margin increased \$239 million, or 9%, for 2009 compared to 2008 primarily due to:

- \$147 million of increases from higher retail prices approved by regulators primarily to recover increased costs of assets placed in service and higher energy costs, including \$13 million of increases in DSM revenue primarily associated with Utah DSM programs;
- \$83 million of increases in net wholesale electricity activities due to \$259 million of significantly lower average prices on wholesale electricity purchases and \$32 million of lower volumes of wholesale electricity purchases, partially offset by \$208 million of lower average prices on wholesale electricity sales;
- \$66 million of increases due to sales to the noncontrolling interest in Bridger Coal;
- \$44 million of increases in sales of renewable energy credits;
- \$27 million of increases due to growth in the average number of commercial and residential customers primarily in Utah; and
- \$13 million of decreases in fuel costs primarily due to lower volumes of coal consumed as a result of increased generating facility overhauls and lower retail demand, partially offset by higher average prices of coal.

The increase in gross margin was partially offset by:

- \$92 million of decreases due to lower average customer usage primarily in Oregon and by industrial customers across PacifiCorp's service territories due to the effects of the current economic conditions; and
- \$26 million of decreases due to lower deferrals of incurred power costs in accordance with established adjustment mechanisms.

Operations and maintenance increased \$50 million, or 5%, primarily due to costs associated with sales to the noncontrolling interest in Bridger Coal.

Depreciation and amortization increased \$59 million, or 12%, primarily due to higher plant in service.

Taxes, other than income taxes increased \$24 million, or 21%, primarily due to costs attributable to Bridger Coal and increased property taxes driven by higher plant in service.

Interest expense increased \$51 million, or 15%, primarily due to higher average debt outstanding, partially offset by lower average rates on variable- and fixed-rate debt.

Allowance for borrowed and equity funds increased \$18 million, or 22%, primarily due to higher qualified construction work-in-progress balances, partially offset by lower average rates.

Interest income increased \$8 million, or 73%, substantially due to interest associated with SB 408.

Income tax expense decreased \$4 million to \$234 million for 2009 compared to 2008, primarily due to higher production tax credits associated with increased production at wind-powered generating facilities, substantially offset by higher pre-tax income. The effective tax rate was 30% for the year ended December 31, 2009 compared to 34% for the year ended December 31, 2008.

Liquidity and Capital Resources

As of December 31, 2010, PacifiCorp's total net liquidity was \$1.086 billion. The components of total net liquidity were as follows (in millions):

Cash and cash equivalents	\$ 31
Available revolving credit facilities	\$ 1,395
Less:	
Short-term debt	(36)
Letters of credit and tax-exempt bond support	(304)
Net revolving credit facilities available	\$ 1,055
Total net liquidity available	\$ 1,086
Unsecured revolving credit facilities:	
Maturity dates ⁽¹⁾	2012-2013
Largest single bank commitment as a % of total ⁽²⁾	15%

(1) For further discussion regarding PacifiCorp's credit facilities, refer to Note 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

(2) An inability of financial institutions to honor their commitments could adversely affect PacifiCorp's short-term liquidity and ability to meet long-term commitments.

PacifiCorp's cash and cash equivalents were \$31 million as of December 31, 2010, compared to \$117 million as of December 31, 2009. PacifiCorp has restricted cash and investments included in other current assets and investments and other assets on the Consolidated Balance Sheets totaling \$6 million and \$88 million as of December 31, 2010 and 2009, respectively. The amount as of December 31, 2009 principally relates to funds held in trust at Bridger Coal for final mine reclamation. Refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Bridger Coal.

In September 2010, the President signed the Small Business Jobs Act into law, extending retroactively to January 1, 2010 the 50% bonus depreciation for qualifying property purchased and placed in service in 2010. In December 2010, the President signed the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 into law, which provided for 100% bonus depreciation for qualifying property purchased and placed in service after September 8, 2010. As a result of the new laws, PacifiCorp's December 31, 2010 tax provision reflected bonus depreciation on qualifying assets placed in service during 2010. Accordingly, PacifiCorp's receivable for income taxes increased to \$345 million as of December 31, 2010.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2010 and 2009 were \$1.41 billion and \$1.5 billion, respectively. The \$90 million decrease was primarily due to changes in collateral posted for derivative contracts, lower net wholesale electricity sales and higher contributions to PacifiCorp's pension plan, partially offset by higher prices approved by regulators and higher income tax receipts in the current year primarily related to bonus depreciation.

Net cash flows from operating activities for the years ended December 31, 2009 and 2008 were \$1.5 billion and \$992 million, respectively. The \$508 million increase was primarily due to higher income tax receipts related to the repairs deduction and bonus depreciation, lower net wholesale electricity purchases, changes in collateral posted for derivative contracts and higher prices approved by regulators.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2010 and 2009 were \$(1.613) billion and \$(2.308) billion, respectively. Capital expenditures decreased \$721 million primarily due to lower expenditures for transmission system investments and wind-powered generating facilities.

Net cash flows from investing activities for the years ended December 31, 2009 and 2008 were \$(2.308) billion and \$(2.076) billion, respectively. Capital expenditures increased \$539 million primarily due to construction costs for the Populus to Terminal transmission line, partially offset by the September 2008 acquisition of Chehalis Power Generating, LLC, an entity owning a 520-MW natural gas-fired generating facility located in Chehalis, Washington, for \$308 million. Chehalis Power Generating, LLC was merged into PacifiCorp immediately following the acquisition.

Capital Expenditures

Capital expenditures, excluding the non-cash allowance for equity funds used during construction ("equity AFUDC"), consisted mainly of the following for the years ended December 31:

2010

- Transmission system investments totaling \$391 million, including construction costs for the first major segment of the Energy Gateway Transmission Expansion Program, a 135-mile, double-circuit, 345-kilovolt transmission line between the Populus substation in southern Idaho and the Terminal substation near Salt Lake City, Utah, which was placed in service in 2010.
- Emissions control equipment totaling \$398 million, including costs for the Dave Johnston generating facility Unit 3, which includes a sulfur dioxide scrubber that was placed in service in May 2010, as well as low nitrogen oxide burners and costs for installation or upgrade of sulfur dioxide scrubbers on various other generating facilities.
- The development and construction of wind-powered generating facilities totaling \$152 million, for the 111-MW Dunlap Ranch I wind-powered generating facility near Medicine Bow, Wyoming, which was placed in service in October 2010.
- Distribution, generation, mining and other infrastructure needed to serve existing and expected demand totaling \$666 million.

2009

- Transmission system investments totaling \$748 million, including construction costs for a major segment of the Energy Gateway Transmission Expansion Program.
- The development and construction of wind-powered generating facilities totaling \$407 million, including 218 MW placed in service in December 2008, 138 MW placed in service in January 2009 and 127 MW placed in service in September 2009. The expenditures also included construction costs for the 111-MW Dunlap Ranch I wind-powered generating facility.
- Emissions control equipment totaling \$345 million, including the installation costs for emissions control equipment at the Dave Johnston generating facility related to the addition of the new sulfur dioxide scrubber on Unit 3 and the replacement of an existing sulfur dioxide scrubber on Unit 4, which is expected to be placed into service during 2012. Additional projects included installation of sulfur dioxide scrubbers on various other generating facilities.
- Distribution, generation, mining and other infrastructure needed to serve existing and expected demand totaling \$828 million.

Financing Activities

Short-term Debt and Revolving Credit Facilities

Regulatory authorities limit PacifiCorp to \$1.5 billion of short-term debt. PacifiCorp had \$36 million of short-term debt outstanding as of December 31, 2010 at a weighted-average interest rate of 0.3% as compared to no short-term debt outstanding as of December 31, 2009. PacifiCorp had no outstanding borrowings under its unsecured revolving credit facilities as of December 31, 2010 or 2009.

For further discussion, refer to Note 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Long-term Debt

In addition to the debt issuances discussed herein, PacifiCorp made scheduled repayments on long-term debt totaling \$15 million and \$138 million during the years ended December 31, 2010 and 2009, respectively.

In January 2009, PacifiCorp issued \$350 million of its 5.50% First Mortgage Bonds due January 15, 2019 and \$650 million of its 6.00% First Mortgage Bonds due January 15, 2039. The net proceeds were used to repay short-term debt, to fund capital expenditures and for general corporate purposes.

In June 2010, PacifiCorp completed a re-offering of a \$45 million series of tax-exempt bond obligations. The interest rate for this obligation was previously fixed for a term which, upon scheduled expiration, was converted to a variable-rate with credit enhancement and liquidity support provided by a \$46 million letter of credit issued under one of PacifiCorp's unsecured revolving credit facilities. In September 2010, PacifiCorp completed a re-offering of variable-rate tax-exempt bond obligations totaling \$38 million. Letters of credit totaling \$39 million were issued under one of PacifiCorp's unsecured revolving credit facilities to provide credit enhancement and liquidity support for these previously unenhanced obligations.

As of December 31, 2010, PacifiCorp had \$601 million of letters of credit available to provide credit enhancement and liquidity support for variable-rate tax-exempt bond obligations totaling \$587 million plus interest. These letters of credit were fully available at December 31, 2010 and expire periodically through May 2012.

PacifiCorp has regulatory authority from the OPUC and the IPUC to issue an additional \$2.0 billion of long-term debt. PacifiCorp must make a notice filing with the WUTC prior to any future issuance. Also, in December 2010, PacifiCorp filed a shelf registration statement with the SEC covering future first mortgage bond issuances.

PacifiCorp's Mortgage and Deed of Trust creates a lien on most of PacifiCorp's electric utility property, allowing the issuance of bonds based on a percentage of utility property additions, bond credits arising from retirement of previously outstanding bonds or deposits of cash. The amount of bonds that PacifiCorp may issue generally is also subject to a net earnings test. As of December 31, 2010, PacifiCorp estimated it would be able to issue up to \$5.9 billion of new first mortgage bonds under the most restrictive issuance test in the mortgage. Any issuances are subject to market conditions and amounts may be further limited by regulatory authorizations or commitments or by covenants and tests contained in other financing agreements. PacifiCorp also has the ability to release property from the lien of the mortgage on the basis of property additions, bond credits or deposits of cash.

PacifiCorp may from time to time seek to acquire its outstanding debt securities through cash purchases in the open market, privately negotiated transactions or otherwise. Any debt securities repurchased by PacifiCorp may be reissued or resold by PacifiCorp from time to time and will depend on prevailing market conditions, PacifiCorp's liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Common Shareholder's Equity

In January 2011, PacifiCorp declared a dividend of \$275 million payable to PPW Holdings LLC, a direct subsidiary of MEHC and PacifiCorp's direct parent company, on February 28, 2011.

Cash capital contributions from MEHC were \$100 million and \$125 million during the years ended December 31, 2010 and 2009, respectively.

Capitalization

PacifiCorp manages its capitalization and liquidity position to maintain a prudent capital structure with an objective of retaining strong investment grade credit ratings, which is expected to facilitate continuing access to flexible borrowing arrangements at favorable costs and rates. This objective, subject to periodic review and revision, attempts to balance the interests of all shareholders, customers and creditors and provide a competitive cost of capital and predictable capital market access.

As a result of authoritative accounting guidance, such as guidance pertaining to consolidations and leases, it is possible that new purchase power and gas agreements, transmission arrangements or amendments to existing arrangements may be accounted for as capital lease obligations or debt on PacifiCorp's financial statements. While PacifiCorp has successfully amended covenants in financing arrangements that may be impacted by these changes, it may be more difficult for PacifiCorp to comply with its capitalization targets or regulatory commitments concerning minimum levels of common equity as a percentage of capitalization. This may lead PacifiCorp to seek amendments or waivers under financing agreements and from regulators, delay or reduce dividends or spending programs, seek additional new equity contributions from its indirect parent company, MEHC, or take other actions.

Future Uses of Cash

PacifiCorp has available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, capital contributions and other sources. These sources are expected to provide funds required for current operations, capital expenditures, debt retirements and other capital requirements. The availability and terms under which PacifiCorp has access to external financing depends on a variety of factors, including PacifiCorp's credit rating, investors' judgment of risk and conditions in the overall capital market, including the condition of the utility industry in general.

Capital Expenditures

PacifiCorp has significant future capital requirements. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, changes in rules and regulations, including environmental; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; and the cost and availability of capital. Expenditures for compliance-related items, such as pollution-control technologies, replacement generation, hydroelectric relicensing, hydroelectric decommissioning, and associated operating costs are generally incorporated into PacifiCorp's rates.

PacifiCorp estimates that it will spend approximately \$5.1 billion on capital projects over the next three years, excluding non-cash equity AFUDC. These capital projects include new generating resources, including renewables; transmission investments; installation of emissions control equipment on existing generating facilities; and distribution investments in new connections, lines and substations.

Forecasted capital expenditures for the years ended December 31 are as follows (in millions):

	2011	2012	2013
Forecasted capital expenditures⁽¹⁾:			
Generation development	\$ 177	\$ 372	\$ 338
Transmission system investment	456	666	610
Environmental	229	149	245
Other	708	609	531
Total	\$ 1,570	\$ 1,796	\$ 1,724

(1) Excludes amounts for non-cash equity AFUDC.

The capital expenditure estimate for generation development projects primarily consists of construction of the approximately 637-MW Lake Side 2 combined-cycle combustion turbine natural gas-fired generating facility adjacent to the existing Lake Side generating facility that is expected to be placed in service in 2014.

Capital projects for transmission system investment include projects associated with the Energy Gateway Transmission Expansion Program totaling \$1.0 billion, including the estimated remaining costs of \$372 million for the 100-mile high-voltage transmission line being built between the Mona substation in central Utah and the Oquirrh substation in the Salt Lake Valley. A 65-mile segment of the Mona to Oquirrh transmission project will be a single-circuit 500-kV transmission line, while the remaining 35-mile segment will be a double-circuit 345-kV transmission line. The project is estimated to cost \$440 million and is expected to be placed in service in 2013. Other segments associated with this program are expected to be placed in service through 2019, depending on siting, permitting and construction schedules.

The capital expenditure estimate for environmental projects includes emissions control equipment to meet anticipated air quality and visibility targets, including the reduction of sulfur dioxide, nitrogen oxide and particulate matter emissions. This estimate includes the installation of new or the replacement of existing emissions control equipment at a number of units at several of PacifiCorp's coal-fired generating facilities.

Capital expenditures related to operating projects consist of routine expenditures for distribution, generation, mining and other infrastructure needed to serve existing and expected demand.

Obligations and Commitments

Contractual Obligations

PacifiCorp has contractual cash obligations that may affect its consolidated financial condition. The following table summarizes PacifiCorp's material contractual cash obligations as of December 31, 2010 (in millions):

	Payments Due By Periods				
	2011	2012-2013	2014-2015	2016 and After	Total
Long-term debt, including interest:					
Fixed-rate obligations	\$ 941	\$ 858	\$ 801	\$ 9,382	\$ 11,982
Variable-rate obligations ⁽¹⁾	5	49	161	464	679
Short-term debt, including interest	36	—	—	—	36
Capital leases, including interest	8	19	15	87	129
Operating leases	6	9	7	39	61
Asset retirement obligations	5	13	22	287	327
Power purchase agreements ⁽²⁾ :					
Electricity commodity contracts	39	97	22	48	206
Electricity capacity contracts	117	146	145	335	743
Electricity mixed contracts	14	28	29	160	231
Transmission	115	205	145	745	1,210
Fuel purchase agreements ⁽³⁾ :					
Natural gas supply and transportation	160	78	78	285	601
Coal supply and transportation	604	1,121	967	2,306	4,998
Other purchase obligations	437	152	36	90	715
Other long-term liabilities ⁽³⁾	85	8	7	58	158
Total contractual cash obligations	<u>\$ 2,572</u>	<u>\$ 2,783</u>	<u>\$ 2,435</u>	<u>\$ 14,286</u>	<u>\$ 22,076</u>

(1) Consists of principal and interest for tax-exempt bond obligations with interest rates scheduled to reset periodically prior to maturity. Future variable interest rates are set at December 31, 2010 rates. Refer to "Interest Rate Risk" in Item 7A of this Form 10-K for additional discussion related to variable-rate liabilities.

(2) Commodity contracts are agreements for the delivery of energy. Capacity contracts are agreements that provide rights to energy output, generally of a specified generating facility. Forecasted or other applicable estimated prices were used to determine total dollar value of the commitments for purposes of the table.

(3) Includes environmental and hydroelectric relicensing commitments recorded in the Consolidated Balance Sheets that are contractually or legally binding and contributions expected to be made to the PacifiCorp Retirement Plan during 2011 as disclosed in Note 11 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. Excludes regulatory liabilities and employee benefit plan obligations that are not legally or contractually fixed as to timing and amount. Deferred income taxes are excluded since cash payments are based primarily on taxable income for each year. Uncertain tax positions are also excluded because the amounts and timing of cash payments are not certain.

Commercial Commitments

PacifiCorp's commercial commitments include surety bonds that provide indemnities for PacifiCorp in relation to various commitments it has to third parties for obligations in the event of default by PacifiCorp. In the event of default by PacifiCorp, the bonding agency would seek recovery from PacifiCorp in the amount of the bond. The majority of these bonds are continuous in nature and renew annually. Based on current contractual commitments, PacifiCorp's level of surety bonding after December 31, 2010 is estimated to be approximately \$25 million per year. This estimate is based on current information and actual amounts may vary due to rate changes or changes to the general operations of PacifiCorp.

Regulatory Matters

PacifiCorp is subject to comprehensive regulation. In addition to the discussion contained herein regarding regulatory matters, refer to Item 1 of this Form 10-K for further discussion regarding PacifiCorp's general regulatory framework.

Certain regulatory matters are subject to uncertainties that require the use of estimates on the Consolidated Financial Statements, particularly that related to SB 408. Refer to Note 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion.

FERC

As a result of a 2007 multi-party settlement with the FERC regarding long-term shared usage, coordinated operation and maintenance, and planning of certain 500-kV transmission lines, PacifiCorp agreed to file a Federal Power Act Section 205 general rate change filing for its system-wide transmission service rates no later than June 1, 2011. PacifiCorp is in the process of preparing for this filing, which will occur no later than the agreed upon date.

State Regulatory Matters

Utah

In March 2009, PacifiCorp filed for an ECAM with the UPSC. The filing recommended that the UPSC adopt the ECAM to recover the difference between base net power costs set in the next Utah general rate case and actual net power costs. The UPSC separated the application into two phases to first address whether the mechanism is in the public interest, and then if it is found to be in the public interest, to determine the type of mechanism that should be implemented. The UPSC completed the phase one hearings in January 2010. In February 2010, the UPSC issued an order to proceed to the second phase, concluding that the public interest determination is dependent on evidence to be provided in phase two. In February 2010, PacifiCorp filed an application with the UPSC seeking approval to defer the difference between the net power costs allowed by the UPSC's final order in PacifiCorp's 2009 general rate case and the actual net power costs incurred. Also in February 2010, the Utah Association of Energy Users filed a motion with the UPSC requesting deferral of incremental renewable energy credit revenue in excess of the renewable energy credit value utilized in Utah rates established by the 2009 general rate case. In July 2010, the UPSC issued an order approving a stipulation that would establish deferred accounts for both net power costs and renewable energy credit revenues in excess of the levels currently included in rates, subject to the UPSC's final determination of the ratemaking treatment of the deferrals. In November 2010, a final hearing on the ECAM was held with the UPSC. A final decision as to whether all or any of the net power costs and renewable energy credit revenues in excess of the levels currently included in rates will be collected from or passed through to customers is under consideration by the UPSC. In December 2010, the UPSC approved a separate stipulation that provides a \$3 million monthly credit to customers effective January 1, 2011 that will be applied toward the UPSC's final decision.

In February 2010, PacifiCorp filed an application with the UPSC requesting an increase of \$34 million associated with two major construction projects that were completed and in service by June 2010. The application requested recovery in conjunction with a future rate change. In March 2010, PacifiCorp updated its application to reflect the cost of capital decisions from the February 2010 general rate case order, reducing the amount requested for recovery to \$33 million. In May 2010, a multi-party stipulation was filed with the UPSC agreeing to recovery of \$31 million. In June 2010, the stipulation was approved by the UPSC.

In August 2010, PacifiCorp filed an application with the UPSC requesting an increase of \$39 million associated with two major construction projects expected to be complete and in service by December 2010. The application requested a 5% increase in rates effective January 2011 encompassing both the \$39 million requested increase and the \$31 million increase approved by the UPSC in June 2010. In December 2010, the UPSC approved a stipulation that provides for a \$64 million increase that encompasses both the February 2010 and the August 2010 applications. The stipulation also provides for collection of a one-time \$16 million surcharge for recovery of amounts related to the February 2010 application that were deferred during the period July 2010 to December 2010. The new rates were effective January 1, 2011.

In January 2011, PacifiCorp filed a general rate case with the UPSC requesting a rate increase of \$232 million, or an average price increase of 14%. If approved by the UPSC, the rates will be effective September 2011.

Oregon

In February 2010, PacifiCorp made its initial filing for the annual TAM with the OPUC for an annual increase of \$69 million to recover the anticipated net power costs forecasted for calendar year 2011. In July 2010, an all-party stipulation was filed with the OPUC agreeing to an increase of \$58 million, or an average price increase of 6%. The OPUC approved the all-party stipulation in September 2010, subject to updates for anticipated net power costs through November 2010. PacifiCorp filed the scheduled updates to net power costs in July and November 2010. In December 2010, PacifiCorp filed a final update to net power costs, reflecting an increase of \$60 million, or an average price increase of 6%. The OPUC approved the increase in December 2010 with an effective date of January 1, 2011.

In March 2010, PacifiCorp filed a general rate case with the OPUC requesting an increase of \$131 million, or an average price increase of 13%. In July 2010, a multi-party stipulation was filed with the OPUC agreeing to an annual increase of \$85 million, or an average price increase of 8%. The stipulation required PacifiCorp to file updated costs for the Populus to Terminal transmission line once the asset was placed in service. In December 2010, PacifiCorp filed the updated costs based on the November 2010 placed-in-service date and reduced the annual increase to \$80 million, or an average price increase of 8%. In December 2010, the OPUC approved the stipulation. The new rates were effective January 1, 2011.

Wyoming

In October 2009, PacifiCorp filed a general rate case with the WPSC requesting a rate increase of \$71 million with an effective date of August 1, 2010. Net power costs included in the general rate case filing reflected an increase in coal costs and the expiration of low cost long-term power purchase contracts. The application was based on a test period ending December 31, 2010. In March 2010, a multi-party stipulation was filed with the WPSC agreeing to an overall rate increase of \$36 million, or an average price increase of 7%, to be implemented in two phases. In May 2010, the WPSC approved the settlement agreement. The first phase of the rate increase, consisting of a \$26 million increase, became effective July 1, 2010 and the second phase, consisting of the remaining \$10 million increase, was effective February 1, 2011.

In January 2010, PacifiCorp filed its annual PCAM application with the WPSC requesting recovery of \$8 million in deferred net power costs. In March 2010, a multi-party stipulation was filed with the WPSC agreeing to reduce the requested recovery to \$4 million. In May 2010, the WPSC approved the settlement agreement allowing for the change in the PCAM surcharge rate effective April 1, 2010.

In April 2010, PacifiCorp filed an application with the WPSC requesting approval of a new ECAM to replace the existing PCAM. The PCAM concluded with the final deferral of net power costs in November 2010 and collection through March 2012. In November 2010, the WPSC approved effective December 1, 2010, the deferral of net power costs incurred above or below base net power costs currently provided for in rates until the WPSC issues an order on PacifiCorp's application for the ECAM. In November 2010, the WPSC held hearings for the establishment and design of an ECAM. In February 2011, the WPSC issued an order approving an ECAM under which the forecast of net power costs will be established in general rate cases and included in the ECAM charges. In addition, 70% of any difference between actual and forecasted net power costs would be subject to the ECAM mechanism between general rate cases.

In February 2011, PacifiCorp filed its final PCAM application with the WPSC requesting recovery of \$16 million in deferred net power costs. If approved by the WPSC, the rates will become effective in April 2011 and will result in an \$11 million rate increase over the \$5 million currently reflected in the tariff.

In November 2010, PacifiCorp filed a general rate case with the WPSC requesting a rate increase of \$98 million, or an average price increase of 17%. If approved by the WPSC, the rates will be effective September 2011.

Washington

In May 2010, PacifiCorp filed a general rate case with the WUTC requesting an annual increase of \$57 million, or an average price increase of 21%. In November 2010, the requested annual increase was reduced to \$49 million, or an average price increase of 18%. If approved by the WUTC, the rates will be effective April 2011.

Idaho

In February 2010, PacifiCorp filed an ECAM application with the IPUC requesting recovery of \$2 million in deferred net power costs. In March 2010, the IPUC issued an order approving PacifiCorp's ECAM application effective April 1, 2010.

In May 2010, PacifiCorp filed a general rate case with the IPUC requesting an annual increase of \$28 million, or an average price increase of 14%. In November 2010, the requested annual increase was reduced to \$25 million, or an average price increase of 12%. In December 2010, the IPUC issued an interim order approving an annual increase of \$14 million, or an average price increase of 7% with an effective date of December 28, 2010. The IPUC plans to issue its final order in February 2011.

In June 2010, the IPUC approved an increase to PacifiCorp's energy efficiency rider to fund DSM programs of \$1 million, or an average price increase of 1%, with an effective date of July 1, 2010. As a result of the 1% increase, the energy efficiency rider increased to 5%. In December 2010, the IPUC reduced the energy efficiency rider to 3%, effective December 28, 2010.

In February 2011, PacifiCorp filed an ECAM application with the IPUC requesting recovery of \$13 million in deferred net power costs. If approved by the IPUC, the new rates will be effective April 1, 2011.

California

In November 2009, PacifiCorp filed a general rate case with the CPUC requesting an annual increase of \$8 million, or an average price increase of 10%. In June 2010, PacifiCorp filed an all-party settlement agreement with the CPUC that reflects an annual increase of \$4 million, or an average price increase of 5%, and includes the establishment of revised depreciation rates on California distribution assets. In September 2010, the CPUC approved the settlement agreement with an effective date of January 1, 2011.

In August 2010, PacifiCorp filed an application with the CPUC to increase rates pursuant to the ECAC. In the application, PacifiCorp requested a rate increase of \$9 million, or an average price increase of 11%. In November 2010, the CPUC approved the ECAC with an effective date of January 1, 2011.

Environmental Laws and Regulations

PacifiCorp is subject to federal, state and local laws and regulations regarding air and water quality, renewable portfolio standards, emissions performance standards, climate change, coal combustion byproducts, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact PacifiCorp's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by the EPA and various other state and local agencies. All such laws and regulations are subject to a range of interpretation, which may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and PacifiCorp is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. PacifiCorp believes it is in material compliance with all applicable laws and regulations. Refer to "Future Uses of Cash" for discussion of PacifiCorp's forecasted environmental-related capital expenditures.

Clean Air Standards

The Clean Air Act is a federal law, administered by the EPA that provides a framework for protecting and improving the nation's air quality and controlling sources of air emissions. The implementation of new standards is generally outlined in State Implementation Plans ("SIPs"). SIPs, which are a collection of regulations, programs and policies to be followed, vary by state and are subject to public hearings and EPA approval. Some states may adopt additional or more stringent requirements than those implemented by the EPA. The major Clean Air Act programs, which most directly affect PacifiCorp's operations, are described below.

National Ambient Air Quality Standards

Under the authority of the Clean Air Act, the EPA sets minimum national ambient air quality standards for six principal pollutants, consisting of carbon monoxide, lead, nitrogen oxides, particulate matter, ozone and sulfur dioxide, considered harmful to public health and the environment. Areas that achieve the standards, as determined by ambient air quality monitoring, are characterized as being in attainment, while those that fail to meet the standards are designated as being nonattainment areas. Generally, sources of emissions in a nonattainment area that are determined to contribute to the nonattainment are required to reduce emissions. Most air quality standards require measurement over a defined period of time to determine the average concentration of the pollutant present.

In December 2009, the EPA designated the Utah counties of Davis and Salt Lake, as well as portions of Box Elder, Cache, Tooele, Utah and Weber counties, to be in nonattainment of the fine particulate matter standard. This designation has the potential to impact PacifiCorp's Little Mountain, Lake Side and Gadsby facilities, depending on the requirements to be established in the Utah SIP. The impact on the PacifiCorp facilities is not anticipated to be significant.

In January 2010, the EPA proposed a rule to strengthen the national ambient air quality standard for ground level ozone. The proposed rule arises out of legal challenges claiming that the March 2008 rule that reduced the standard from 80 parts per billion to 75 parts per billion was not strict enough. The new rule proposes a standard between 60 and 70 parts per billion. The EPA has delayed issuance of the final ozone standards until July 2011.

In January 2010, the EPA finalized a one-hour air quality standard for nitrogen dioxide at 0.10 part per million. State attainment designations were required to be submitted to the EPA by January 1, 2011, and the EPA must finalize the designations by January 1, 2012.

In June 2010, the EPA finalized a new national ambient air quality standard for sulfur dioxide. Under the new rule, the existing 24-hour and annual standards for sulfur dioxide, which were 140 parts per billion measured over 24 hours and 30 parts per billion measured over an entire year, were replaced with a new one-hour standard of 75 parts per billion. The new rule will utilize a three-year average to determine attainment. The rule will utilize source modeling, in addition to the installation of ambient monitors where sulfur dioxide emissions impact populated areas, with new monitors required to be in-service no later than January 2013. Attainment designations are due by June 2012, with SIPs due by 2014 and final attainment demonstrations by August 2017.

As new, more stringent standards are adopted, the number of counties designated as nonattainment areas is likely to increase. Businesses operating in newly designated nonattainment counties could face increased regulation and costs to monitor or reduce emissions. For instance, existing major emissions sources may have to install reasonably available control technologies to achieve certain reductions in emissions and undertake additional monitoring, recordkeeping and reporting. The construction or modification of facilities that are sources of emissions could become more difficult in nonattainment areas. Until additional monitoring and modeling is conducted, the impacts on PacifiCorp cannot be determined.

Clean Air Mercury Rule

The Clean Air Mercury Rule ("CAMR"), issued by the EPA in March 2005, was the United States' first attempt to regulate mercury emissions from coal-fired generating facilities through the use of a market-based cap-and-trade system. The CAMR, which mandated emissions reductions of approximately 70% by 2018, was overturned by the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") in February 2008. The EPA plans to propose a new rule that will require coal-fired generating facilities to reduce mercury emissions by utilizing a mandated "Maximum Achievable Control Technology" standard rather than a cap-and-trade system. In addition to regulating mercury under the new rule, the EPA may regulate other hazardous air pollutants. Under a consent decree, the EPA must issue a proposed rule to regulate mercury emissions by March 2011 and a final rule no later than November 2011. If adopted, the new rule will likely result in incremental costs to install and maintain mercury emissions control equipment at each of PacifiCorp's coal-fired generating facilities and would increase the cost of providing service to customers. Until the EPA issues the proposed and final rules, the impacts on PacifiCorp cannot be determined.

Regional Haze

The EPA has initiated a regional haze program intended to improve visibility in designated federally protected areas ("Class I areas"). Some of PacifiCorp's generating facilities meet the threshold applicability criteria to be eligible units under the Clean Air Visibility Rules. In accordance with the federal requirements, states were required to submit SIPs by December 2007 to demonstrate reasonable progress towards achieving natural visibility conditions in Class I areas by requiring emissions controls, known as best available retrofit technology, on sources constructed between 1962 and 1977 with emissions that are anticipated to cause or contribute to impairment of visibility. Wyoming issued best available retrofit technology permits to PacifiCorp on December 31, 2009, requiring PacifiCorp to implement emissions control projects that are consistent with the planned emissions reduction projects at PacifiCorp's Wyoming generating facilities. PacifiCorp appealed certain provisions of the Naughton and Jim Bridger generating facilities' permits, but the appeals were settled. Utah submitted its SIP and suggested that the emissions reduction projects planned by PacifiCorp are sufficient to meet its initial emissions reduction requirements. Utah is currently in the process of amending its SIP submittal, which will be open for public comment until March 2011. In January 2009, the EPA found that 37 states, including Wyoming, had failed to file a SIP that met some or all of the basic regional haze program requirements. Wyoming submitted its regional haze SIP to the EPA in January 2011. PacifiCorp believes that its planned emissions reduction projects will satisfy the regional haze requirements in Utah and Wyoming. It is possible that additional controls may be required after the respective SIPs have been submitted and approved by the EPA or that the timing of installation of planned controls could change.

New Source Review

Under existing New Source Review ("NSR") provisions of the Clean Air Act, any facility that emits regulated pollutants is required to obtain a permit from the EPA or a state regulatory agency prior to (a) beginning construction of a new major stationary source of a regulated pollutant or (b) making a physical or operational change to an existing stationary source of such pollutants that increases certain levels of emissions, unless the changes are exempt under the regulations (including routine maintenance, repair and replacement of equipment). In general, projects subject to NSR regulations require pre-construction review and permitting under the Prevention of Significant Deterioration ("PSD") provisions of the Clean Air Act. Under the PSD program, a project that emits threshold levels of regulated pollutants must undergo an analysis to determine the best available control technology and evaluate the most effective emissions controls after consideration of a number of factors. Violations of NSR regulations, which may be alleged by the EPA, states, environmental groups and others, potentially subject a company to material fines and other sanctions and remedies, including installation of enhanced pollution controls and funding of supplemental environmental projects.

As part of an industry-wide investigation to assess compliance with the NSR and PSD provisions, the EPA has requested information and supporting documentation from numerous utilities regarding their capital projects for various generating facilities. A NSR enforcement case against an unrelated utility has been decided by the United States Supreme Court, holding that an increase in the annual emissions of a generating facility, when combined with a modification (i.e., a physical or operational change), may trigger NSR permitting. Between 2001 and 2003, PacifiCorp responded to requests for information relating to its capital projects at its generating facilities. PacifiCorp has been engaged in periodic discussions with the EPA over several years regarding PacifiCorp's historical projects and their compliance with NSR and PSD provisions. Final resolution has not been achieved. PacifiCorp cannot predict the outcome of its discussions with the EPA at this time; however, PacifiCorp could be required to install additional emissions controls and incur additional costs and penalties in the event it is determined that PacifiCorp's historical projects did not meet all regulatory requirements.

Numerous changes have been proposed to the NSR rules and regulations over the last several years. In addition to the proposed changes, differing interpretations by the EPA and the courts create risk and uncertainty for entities when seeking permits for new projects and installing emissions controls at existing facilities under NSR requirements. PacifiCorp monitors these changes and interpretations to ensure permitting activities are conducted in accordance with the applicable requirements.

Climate Change

The increased global attention to climate change has resulted in significant measures being proposed at the federal level to regulate GHG emissions. The United States Congress has considered, but has not adopted comprehensive climate change legislation, which included a market-based cap-and-trade program that was intended to reduce GHG emissions 83% below 2005 levels by 2050.

In December 2009, the EPA published its findings that GHG threaten the public health and welfare and is pursuing regulation of GHG emissions under the Clean Air Act. Additionally, in May 2010, the EPA issued the greenhouse gas "tailoring rule" to address permitting requirements for GHG after determining that GHG are subject to regulation and would trigger Clean Air Act permitting requirements for stationary sources beginning in January 2011. Numerous lawsuits have been filed on both the EPA's endangerment finding and the tailoring rule and are pending in the D.C. Circuit.

PacifiCorp supports the implementation of reasonable emissions caps, but opposes trading mechanisms that impose additional costs and do not result in decreased emissions. PacifiCorp also believes that any law or regulation should provide a reasonable transition period to allow the phase in of low-carbon generating technologies that will achieve sustainable and cost-effective GHG emissions reduction benefits.

While the debate continues at the federal and international level over the direction of climate change policy, several states have developed or are developing state-specific laws or regional initiatives to report or mitigate GHG emissions. In addition, governmental, non-governmental and environmental organizations have become more active in pursuing climate change related litigation under existing laws.

PacifiCorp voluntarily reports its GHG emissions to the California Climate Action Registry and The Climate Registry. In September 2009, the EPA issued its final rule regarding mandatory reporting of GHG ("GHG Reporting") beginning January 1, 2010. Under GHG Reporting, suppliers of fossil fuels, manufacturers of vehicles and engines, and facilities that emit 25,000 metric tons or more per year of GHG are required to submit annual reports to the EPA. PacifiCorp is subject to this requirement and will submit its first report by March 31, 2011.

PacifiCorp is committed to operating in an environmentally responsible manner. Examples of PacifiCorp's significant investments in programs and facilities that will mitigate its GHG emissions include:

- PacifiCorp owns the second largest portfolio of wind-powered generating capacity in the United States among rate-regulated utilities. As of December 31, 2010, PacifiCorp owned 1,032 MW of wind-powered generating capacity and has purchase power agreements with 705 MW of wind-powered generating capacity. PacifiCorp has invested \$2.1 billion in wind-powered generating facilities.
- PacifiCorp owns 1,157 MW of hydroelectric generating capacity.
- PacifiCorp's Energy Gateway Transmission Expansion Program represents a plan to build approximately 2,000 miles of new high-voltage transmission lines with an estimated cost exceeding \$6 billion. The plan includes several transmission line segments that will: (a) address customer load growth; (b) improve system reliability; (c) reduce transmission system constraints; (d) provide access to diverse generation resources, including renewable resources; and (e) improve the flow of electricity throughout PacifiCorp's six-state service area.
- PacifiCorp has offered customers a comprehensive set of DSM programs for more than 20 years. The programs assist customers to manage the timing of their usage, as well as to reduce overall energy consumption, resulting in lower utility bills.
- PacifiCorp has installed and upgraded emissions control equipment at certain of its coal-fired generating facilities to reduce emissions of sulfur dioxide and nitrogen oxides.

The impact of pending federal, regional, state and international accords, legislation, regulation, or judicial proceedings related to climate change cannot be quantified in any meaningful range at this time. New requirements limiting GHG emissions could have a material adverse impact on PacifiCorp, the United States and the global economy. Companies and industries with higher GHG emissions, such as utilities with significant coal-fired generating facilities, will be subject to more direct impacts and greater financial and regulatory risks. The impact is dependent on numerous factors, none of which can be meaningfully quantified at this time. These factors include, but are not limited to, the magnitude and timing of GHG emissions reduction requirements; the design of the requirements; the cost, availability and effectiveness of emissions control technology; the price, distribution method and availability of offsets and allowances used for compliance; government-imposed compliance costs; and the existence and nature of incremental cost recovery mechanisms. Examples of how new requirements may impact PacifiCorp include:

- Additional costs may be incurred to purchase required emissions allowances under any market-based cap-and-trade system in excess of allocations that are received at no cost. These purchases would be necessary until new technologies could be developed and deployed to reduce emissions or lower carbon generation is available;
- Acquiring and renewing construction and operating permits for new and existing facilities may be costly and difficult;
- Additional costs may be incurred to purchase and deploy new generating technologies;
- Costs may be incurred to retire existing coal facilities before the end of their otherwise useful lives or to convert them to burn fuels, such as natural gas or biomass, that result in lower emissions;
- Operating costs may be higher and unit outputs may be lower;
- Higher interest and financing costs and reduced access to capital markets may result to the extent that financial markets view climate change and GHG emissions as a financial risk; and
- PacifiCorp's electric transmission and retail sales may be impacted in response to changes in customer demand and requirements to reduce GHG emissions.

PacifiCorp expects it will be allowed to recover the prudently incurred costs to comply with climate change requirements.

The impact of events or conditions caused by climate change, whether from natural processes or human activities, could vary widely, from highly localized to worldwide, and the extent to which a utility's operations may be affected is uncertain. Climate change may cause physical and financial risk through, among other things, sea level rise, changes in precipitation and extreme weather events. Consumer demand for energy may increase or decrease, based on overall changes in weather and as customers promote lower energy consumption through the continued use of energy efficiency programs or other means. Availability of resources to generate electricity, such as water for hydroelectric production and cooling purposes, may also be impacted by climate change and could influence PacifiCorp's existing and future electricity generating portfolio. These issues may have a direct impact on the costs of electricity production and increase the price customers pay or their demand for electricity.

International Accords

Under the United Nations Framework Convention on Climate Change, adopted in 1992, members of the convention meet periodically to discuss international responses to climate change. To date, the United States has not made a binding reduction commitment as a result of these international discussions.

Federal Legislation

In June 2009, the United States House of Representatives passed the American Clean Energy and Security Act of 2009 ("Waxman-Markey bill"). In addition to a federal RPS, which would have required utilities to obtain a portion of their energy from certain qualifying renewable sources and energy efficiency measures, the bill required a reduction in GHG emissions beginning in 2012, with emissions reduction targets of 3% below 2005 levels by 2012; 17% below 2005 levels by 2020; 42% below 2005 levels by 2030; and 83% below 2005 levels by 2050 under a cap-and-trade program. Similar legislation was introduced in the Senate, but it did not pass.

Greenhouse Gas Tailoring Rule

The EPA finalized the GHG "tailoring rule" in May 2010 requiring new or modified sources of GHG emissions with increases of 75,000 or more tons per year of total GHG to determine the best available control technology for their GHG emissions beginning in January 2011. New or existing major sources will also be subject to Title V operating permit requirements for GHG. Beginning July 1, 2011 through June 30, 2013, new construction projects that emit GHG emissions of at least 100,000 tons per year and modifications of existing facilities that increase GHG emissions by at least 75,000 tons per year will be subject to permitting requirements and facilities that were previously not subject to Title V permitting requirements will be required to obtain Title V permits if they emit at least 100,000 tons per year of carbon dioxide equivalents. Several legal challenges have been filed to the EPA's final GHG tailoring rule in the D.C. Circuit. The EPA issued a GHG best available control technology guidance document in November 2010 in an effort to provide permitting authorities guidance on how to conduct a best available control technology review for GHG. Until the permitting authorities begin to implement the tailoring rule and determine what constitutes best available control technology for GHG, the impacts of the tailoring rule on PacifiCorp cannot be fully determined.

Regional and State Activities

Several states have developed state-specific laws or regional legislative initiatives to report or mitigate GHG emissions that are expected to impact PacifiCorp, including:

- The Western Climate Initiative, a comprehensive regional effort to reduce GHG emissions by 15% below 2005 levels by 2020 through a cap-and-trade program that includes the electricity sector. The Western Climate Initiative includes the states of California, Montana, New Mexico, Oregon, Utah and Washington and the Canadian provinces of British Columbia, Manitoba, Ontario and Quebec. The state and provincial partners have agreed to begin reporting GHG emissions in 2011 for emissions that occurred in 2010. The first phase of the cap-and-trade program is scheduled to begin on January 1, 2012.
- An executive order signed by California's governor in June 2005 would reduce GHG emissions in that state to 2000 levels by 2010, to 1990 levels by 2020 and 80% below 1990 levels by 2050. The California Air Resources Board proposed regulations to adopt a GHG cap-and-trade program in October 2010; however, those regulations have not yet been finalized. In addition, California has adopted legislation that imposes a GHG emissions performance standard to all electricity generated within the state or delivered from outside the state that is no higher than the GHG emissions levels of a state-of-the-art combined-cycle natural gas-fired generating facility, as well as legislation that adopts an economy-wide cap on GHG emissions to 1990 levels by 2020.
- Over the past several years, the states of California, Washington and Oregon have adopted GHG emissions performance standards for base load electrical generating resources. Under the laws in all three states, the emissions performance standards provide that emissions must not exceed 1,100 lbs of carbon dioxide per MWh. These GHG emissions performance standards generally prohibit electric utilities from entering into long-term financial commitments (e.g., new ownership investments, upgrades, or new or renewed contracts with a term of 5 or more years) unless any base load generation supplied under long-term financial commitments comply with the GHG emissions performance standards.
- The Washington and Oregon governors enacted legislation in May 2007 and August 2007, respectively, establishing goals for the reduction of GHG emissions in their respective states. Washington's goals seek to (a) reduce emissions to 1990 levels by 2020; (b) reduce emissions to 25% below 1990 levels by 2035; and (c) reduce emissions to 50% below 1990 levels by 2050, or 70% below Washington's forecasted emissions in 2050. Oregon's goals seek to (a) cease the growth of Oregon GHG emissions by 2010; (b) reduce GHG levels to 10% below 1990 levels by 2020; and (c) reduce GHG levels to at least 75% below 1990 levels by 2050. Each state's legislation also calls for state government to develop policy recommendations in the future to assist in the monitoring and achievement of these goals.

Renewable Portfolio Standards

The RPS described below could significantly impact PacifiCorp's consolidated financial results. Resources that meet the qualifying electricity requirements under the RPS vary from state to state. Each state's RPS requires some form of compliance reporting and PacifiCorp can be subject to penalties in the event of noncompliance.

In November 2006, Washington voters approved a ballot initiative establishing a RPS requirement for qualifying electric utilities, including PacifiCorp. The requirements are 3% of retail sales by January 1, 2012 through 2015, 9% of retail sales by January 1, 2016 through 2019 and 15% of retail sales by January 1, 2020. The WUTC has adopted final rules to implement the initiative.

In June 2007, the Oregon Renewable Energy Act ("OREA") was adopted, providing a comprehensive renewable energy policy for Oregon. Subject to certain exemptions and cost limitations established in the OREA, PacifiCorp and other qualifying electric utilities must meet minimum qualifying electricity requirements for electricity sold to retail customers of at least 5% in 2011 through 2014, 15% in 2015 through 2019, 20% in 2020 through 2024, and 25% in 2025 and subsequent years. As required by the OREA, the OPUC has approved an automatic adjustment clause to allow an electric utility, including PacifiCorp, to recover prudently incurred costs of its investments in renewable energy generating facilities and associated transmission costs.

California RPS requires electric utilities to increase their procurement of eligible renewable resources by at least 1% of their annual retail electricity sales per year so that 20% of their annual electricity sales are procured from eligible renewable resources by no later than December 31, 2010. PacifiCorp expects that it will meet this compliance target for which the underlying data is subject to verification by the California Energy Commission and review by the CPUC.

In September 2010, the California Air Resources Board unanimously adopted a Renewable Electricity Standard ("RES") pursuant to Executive Order S-21-09 issued in September 2009 under California's Global Warming Solutions Act to expand existing RPS targets to 33% by 2020 for most retail sellers of electricity in California, including PacifiCorp. Additional changes to the RES are anticipated, in part due to potential impacts of Senate Bill 23 that was introduced in the California Legislature in December 2010. PacifiCorp cannot predict the final outcome of the California legislation or how the RES or Senate Bill 23 may interact with the requirements of the California RPS.

In March 2008, Utah's governor signed Utah Senate Bill 202. Among other things, this law provides that, beginning in the year 2025, 20% of adjusted retail electric sales of all Utah utilities be supplied by renewable energy, if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions, and for sales avoided as a result of energy efficiency and DSM programs. Qualifying renewable energy sources can be located anywhere in the WECC areas, and renewable energy credits can be used.

Water Quality Standards

The federal Water Pollution Control Act ("Clean Water Act") establishes the framework for maintaining and improving water quality in the United States through a program that regulates, among other things, discharges to and withdrawals from waterways. The Clean Water Act requires that cooling water intake structures reflect the "best technology available for minimizing adverse environmental impact" to aquatic organisms. In July 2004, the EPA established significant new technology-based performance standards for existing electric generating facilities that take in more than 50 million gallons of water per day. These rules are aimed at minimizing the adverse environmental impacts of cooling water intake structures by reducing the number of aquatic organisms lost as a result of water withdrawals. In response to a legal challenge to the rule, in January 2007, the Second Circuit remanded almost all aspects of the rule to the EPA, without addressing whether companies with cooling water intake structures were required to comply with these requirements. On appeal from the Second Circuit, in April 2009, the United States Supreme Court ruled that the EPA permissibly relied on a cost-benefit analysis in setting the national performance standards regarding "best technology available for minimizing adverse environmental impact" at cooling water intake structures and in providing for cost-benefit variances from those standards as part of the §316(b) Clean Water Act Phase II regulations. The United States Supreme Court remanded the case back to the Second Circuit to conduct further proceedings consistent with its opinion. Compliance and the potential costs of compliance, therefore, cannot be ascertained until such time as the Second Circuit takes action or further action is taken by the EPA. Currently, PacifiCorp's Dave Johnston generating facility, which has water cooling towers, exceeds the 50 million gallons of water per day intake threshold. In the event that PacifiCorp's existing intake structures require modification or alternative technology required by new rules, expenditures to comply with these requirements could be significant. PacifiCorp believes that it currently has, or has initiated the process to receive, all required water quality permits.

Coal Combustion Byproduct Disposal

In December 2008, an ash impoundment dike at the Tennessee Valley Authority's Kingston power plant collapsed after heavy rain, releasing a significant amount of fly ash and bottom ash, coal combustion byproducts, and water to the surrounding area. In light of this incident, federal and state officials have called for greater regulation of the storage and disposal of coal combustion byproducts. In May 2010, the EPA released a proposed rule to regulate the management and disposal of coal combustion byproducts, presenting two alternatives to regulation under the Resource Conservation and Recovery Act ("RCRA"). Under the first option, coal combustion byproducts would be regulated as special waste under RCRA Subtitle C and the EPA would establish requirements for coal combustion byproducts from the point of generation to disposition, including the closure of disposal units. Alternatively, the EPA is considering regulation under RCRA Subtitle D under which it would establish minimum nationwide standards for the disposal of coal combustion byproducts. Under both options, surface impoundments utilized for coal combustion byproducts would have to be cleaned and closed unless they could meet more stringent regulatory requirements; in addition, more stringent requirements would be implemented for new ash landfills and expansions of existing ash landfills. PacifiCorp operates 16 surface impoundments and six landfills that contain coal combustion byproducts. These ash impoundments and landfills may be impacted by the newly proposed regulation, particularly if the materials are regulated as hazardous or special waste under RCRA Subtitle C, and could pose significant additional costs associated with ash management and disposal activities at PacifiCorp's coal-fired generating facilities. The public comment period closed in November 2010; however, the timing of the final rule is not known. The impact of the proposed regulations on coal combustion byproducts cannot be determined at this time.

Other

Other laws, regulations and agencies to which PacifiCorp is subject to include, but are not limited to:

- The federal Comprehensive Environmental Response, Compensation and Liability Act and similar state laws may require any current or former owners or operators of a disposal site, as well as transporters or generators of hazardous substances sent to such disposal site, to share in environmental remediation costs.
- The federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes establish operational, reclamation and closure standards that must be met during and upon completion of mining activities.
- The FERC oversees the relicensing of existing hydroelectric systems and is also responsible for the oversight and issuance of licenses for new construction of hydroelectric systems, dam safety inspections and environmental monitoring. Refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the relicensing of certain of PacifiCorp's existing hydroelectric facilities.

Collateral and Contingent Features

PacifiCorp's senior secured and senior unsecured debt credit ratings are as follows:

	<u>Fitch</u>	<u>Moody's</u>	<u>Standard & Poor's</u>
Senior secured debt	A-	A2	A
Senior unsecured debt	BBB+	Baa1	A-
Outlook	Stable	Stable	Stable

Debt and preferred securities of PacifiCorp are rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of PacifiCorp's ability to, in general, meet the obligations of its issued debt or preferred securities. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time.

PacifiCorp has no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt and a change in ratings is not an event of default under the applicable debt instruments. PacifiCorp's unsecured revolving credit facilities do not require the maintenance of a minimum credit rating level in order to draw upon their availability. However, commitment fees and interest rates under the credit facilities are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities. Certain authorizations or exemptions by regulatory commissions for the issuance of securities are valid as long as PacifiCorp maintains investment grade ratings on senior secured debt. A downgrade below that level would necessitate new regulatory applications and approvals.

In accordance with industry practice, certain wholesale energy agreements, including derivative contracts, contain provisions that require PacifiCorp to maintain specific credit ratings on its unsecured debt from one or more of the three recognized credit rating agencies. These agreements, including derivative contracts, may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" in the event of a material adverse change in PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2010, PacifiCorp's credit ratings from the three recognized credit rating agencies were investment grade. If all credit-risk-related contingent features or adequate assurance provisions for these agreements, including derivative contracts, had been triggered as of December 31, 2010, PacifiCorp would have been required to post \$225 million of additional collateral. PacifiCorp's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation or other factors. Refer to Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for a discussion of PacifiCorp's collateral requirements specific to PacifiCorp's derivative contracts.

In July 2010, the President signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Reform Act"). The Reform Act reshapes financial regulation in the United States by creating new regulators, regulating new markets and firms and providing new enforcement powers to regulators. Virtually all major areas of the Reform Act, including collateral requirements on derivative contracts, will be the subject of regulatory interpretation and implementation rules requiring rulemaking proceedings that may take several years to complete.

PacifiCorp is a party to derivative contracts, including over-the-counter derivative contracts. The Reform Act provides for extensive new regulation of over-the-counter derivative contracts and certain market participants, including imposition of mandatory clearing, exchange trading, capital and margin requirements for "swap dealers" and "major swap participants." The Reform Act provides certain exemptions from these regulations for commercial end-users that use derivatives to hedge and manage the commercial risk of their businesses. Although PacifiCorp generally does not enter into over-the-counter derivative contracts for purposes unrelated to hedging of commercial risk and does not believe it will be considered a swap dealer or major swap participant, the outcome of the rulemaking proceedings cannot be predicted and, therefore, the impact of the Reform Act on PacifiCorp's consolidated financial results cannot be determined at this time.

Limitations

In addition to PacifiCorp's capital structure objectives, its debt capacity is also governed by its contractual and regulatory commitments.

PacifiCorp's revolving credit and other financing agreements contain customary covenants and default provisions, including a covenant not to exceed a specified debt-to-capitalization ratio of 0.65 to 1.0. Management believes that PacifiCorp could have borrowed an additional \$7.2 billion as of December 31, 2010 without exceeding this threshold. Any additional borrowings 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.

The state regulatory orders that authorized the acquisition by MEHC contain restrictions on PacifiCorp's ability to pay common dividends to the extent that they would reduce PacifiCorp's common stock equity below specified percentages of defined capitalization.

As of December 31, 2010, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to MEHC or PPW Holdings LLC without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 46.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. This minimum level of common equity declines to 45.25% for the year ending December 31, 2011 and 44% thereafter. The terms of this commitment treat 50% of PacifiCorp's remaining balance of preferred stock in existence prior to the acquisition of PacifiCorp by MEHC as common equity. As of December 31, 2010, PacifiCorp's actual common stock equity percentage, as calculated under this measure, was 55.8%, and management believes that PacifiCorp could have declared a dividend of \$2.320 billion under this commitment.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings LLC or MEHC if PacifiCorp's senior unsecured debt is rated BBB- or lower by Standard & Poor's Rating Services or Fitch Ratings or Baa3 or lower by Moody's Investor Service, as indicated by two of the three rating services. As of December 31, 2010, PacifiCorp's senior unsecured debt was rated A- by Standard & Poor's Rating Services, BBB+ by Fitch Ratings and Baa1 by Moody's Investor Service.

Inflation

Historically, overall inflation and changing prices in the economies where PacifiCorp operates have not had a significant impact on PacifiCorp's consolidated financial results. PacifiCorp operates under a cost-of-service based rate structure administered by various state commissions and the FERC. Under this rate structure, PacifiCorp is allowed to include prudent costs in its rates, including the impact of inflation. PacifiCorp attempts to minimize the potential impact of inflation on its operations by employing prudent risk management and hedging strategies and by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances. There can be no assurance that such actions will be successful.

Off-Balance Sheet Arrangements

PacifiCorp from time to time enters into arrangements in the normal course of business to facilitate commercial transactions with third parties that involve guarantees or similar arrangements. PacifiCorp currently has indemnification obligations for breaches of warranties or covenants in connection with the sale of certain assets. In addition, PacifiCorp evaluates potential obligations that arise out of variable interests in unconsolidated entities, determined in accordance with authoritative accounting guidance. PacifiCorp believes that the likelihood that it would be required to perform or otherwise incur any significant losses associated with any of these obligations is remote. Refer to Notes 10 and 17 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for more information on these obligations and arrangements.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting PacifiCorp, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Consolidated Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty. Accordingly, the amounts currently reflected on the Consolidated Financial Statements will likely change in the future as additional information becomes available. The following critical accounting estimates are impacted significantly by PacifiCorp's methods, judgments and assumptions used in the preparation of the Consolidated Financial Statements and should be read in conjunction with PacifiCorp's Summary of Significant Accounting Policies included in Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Accounting for the Effects of Certain Types of Regulation

PacifiCorp prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, PacifiCorp is required to defer the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future rates.

PacifiCorp continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition, which could limit PacifiCorp's ability to recover its costs. Based upon this continuous evaluation, PacifiCorp believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels and is subject to change in the future. If it becomes no longer probable that the deferred costs or income will be included in future rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income. Total regulatory assets were \$1.715 billion and total regulatory liabilities were \$849 million as of December 31, 2010. Refer to Note 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's regulatory assets and liabilities.

Derivatives

PacifiCorp is exposed to the impact of market fluctuations in commodity prices and interest rates. PacifiCorp is principally exposed to electricity and natural gas commodity price risk as it has an obligation to serve retail customer load in its service territories. PacifiCorp's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather; market liquidity; generating facility availability; customer usage; storage; and transmission and transportation constraints. Interest rate risk exists on variable-rate debt, commercial paper and future debt issuances. PacifiCorp has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business. PacifiCorp employs a number of different derivative contracts, including forwards, futures, options, swaps and other agreements, to manage price risk for electricity, natural gas and other commodities and interest rate risk. PacifiCorp does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices. Refer to Notes 6 and 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's derivative contracts.

Measurement Principles

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which PacifiCorp transacts. When quoted prices for identical contracts are not available, PacifiCorp uses forward price curves. Forward price curves represent PacifiCorp's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. PacifiCorp bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent energy brokers, exchanges, direct communication with market participants and actual transactions executed by PacifiCorp. Market price quotations for certain major electricity and natural gas trading hubs are generally readily obtainable for the first six years; therefore, PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. Market price quotations for other electricity and natural gas trading hubs are not as readily obtainable for the first six years. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, PacifiCorp uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on significant unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts. The assumptions used in these models are critical, since any changes in assumptions could have a significant impact on the estimated fair value of the contracts.

Contracts with explicit or embedded optionality are valued by separating each contract into its physical and financial forward, swap and option components. Forward and swap components are valued against the appropriate forward price curve. Option components are valued using Black-Scholes-type models, such as European option, Asian option, spread option and best-of option, with the appropriate forward price curve and other inputs.

Classification and Recognition Methodology

Almost all of PacifiCorp's derivative contracts are probable of inclusion in rates or are accounted for as cash flow hedges. Therefore, changes in the estimated fair value of derivative contracts are generally recorded as net regulatory assets or accumulated other comprehensive income (loss) ("AOCI"). Accordingly, amounts are generally not recognized in earnings until the contracts are settled and the forecasted transaction has occurred. As of December 31, 2010, PacifiCorp had \$487 million recorded as net regulatory assets and \$- million recorded as AOCI, before tax, related to derivative contracts on the Consolidated Balance Sheets. If it becomes no longer probable that a derivative contract will be included in rates, the net regulatory asset will be written off and recognized in earnings. For PacifiCorp's derivative contracts designated as hedging contracts, PacifiCorp discontinues hedge accounting prospectively when it has determined that a derivative contract no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative contract no longer qualifies as an effective hedge, future changes in the estimated fair value of the derivative contract are charged to earnings. Gains and losses related to discontinued hedges that were previously recorded in AOCI will remain in AOCI until the contract settles and the hedged item is recognized in earnings, unless it becomes probable that the hedged forecasted transaction will not occur, at which time associated deferred amounts in AOCI will be immediately recognized in earnings.

Pension and Other Postretirement Benefits

PacifiCorp sponsors defined benefit pension and other postretirement benefit plans that cover the majority of its employees. In addition, certain bargaining unit employees participate in joint trust plans to which PacifiCorp contributes. PacifiCorp recognizes the funded status of its defined benefit pension and other postretirement benefit plans on the Consolidated Balance Sheets. Funded status is the fair value of plan assets minus the benefit obligation as of the measurement date. As of December 31, 2010, PacifiCorp recognized a net liability totaling \$468 million for the under-funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2010, amounts not yet recognized as a component of net periodic benefit cost that were included in regulatory assets and AOCI totaled \$595 million and \$11 million, respectively.

The expense and benefit obligations relating to these defined benefit pension and other postretirement benefit plans are based on actuarial valuations. Inherent in these valuations are key assumptions, including discount rates, expected long-term rate of return on plan assets and healthcare cost trend rates. These actuarial assumptions are reviewed annually and modified as appropriate. PacifiCorp believes that the assumptions utilized in recording obligations under the plans are reasonable based on prior experience and current market conditions. Refer to Note 11 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for disclosures about PacifiCorp's defined benefit pension and other postretirement benefit plans, including the key assumptions used to calculate the funded status and net periodic benefit cost for these plans as of and for the year ended December 31, 2010.

PacifiCorp chooses a discount rate based upon high quality fixed-income investment yields in effect as of the measurement date that corresponds to the expected benefit period. The pension and other postretirement benefit liabilities, as well as expenses, increase as the discount rate is reduced.

In establishing its assumption as to the expected long-term rate of return on plan assets, PacifiCorp utilizes the expected asset allocation and return assumptions for each asset class based on historical performance and forward-looking views of the financial markets. Pension and other postretirement benefits expense increases as the expected long-term rate of return on plan assets decreases. PacifiCorp regularly reviews its actual asset allocations and rebalances its investments to its targeted allocations when considered appropriate.

PacifiCorp chooses a healthcare cost trend rate that reflects the near and long-term expectations of increases in medical costs and corresponds to the expected benefit payment periods. The healthcare cost trend rate gradually declines to 5% in 2016, at which point the rate is assumed to remain constant. Refer to Note 11 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for healthcare cost trend rate sensitivity disclosures.

The actuarial assumptions used may differ materially from period to period due to changing market and economic conditions. These differences may result in a significant impact to pension and other postretirement benefits expense and the funded status. If changes were to occur for the following assumptions, the approximate effect on the Consolidated Financial Statements would be as follows (in millions):

	Pension Plans		Other Postretirement Benefit Plan	
	+0.5%	-0.5%	+0.5%	-0.5%
Effect on December 31, 2010 Benefit Obligations:				
Discount rate	\$ (64)	\$ 70	\$ (32)	\$ 36
Effect on 2010 Periodic Cost:				
Discount rate	\$ (4)	\$ 4	\$ (2)	\$ 2
Expected rate of return on plan assets	(5)	5	(2)	2

A variety of factors affect the funded status of the plans, including asset returns, discount rates, plan changes and the plan funding practices of PacifiCorp. Federal laws may require PacifiCorp to increase future contributions to its pension plans and there may be more volatility in annual contributions than historically experienced, which could have a material impact on consolidated financial results.

Income Taxes

In determining PacifiCorp's income taxes, management is required to interpret complex tax laws and regulations, which includes consideration of regulatory implications imposed by PacifiCorp's various regulatory jurisdictions. PacifiCorp's income tax returns are subject to continuous examinations by federal, state and local tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. PacifiCorp recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. Although the ultimate resolution of PacifiCorp's federal, state and local tax examinations is uncertain, PacifiCorp believes it has made adequate provisions for these tax positions. The aggregate amount of any additional tax liabilities that may result from these examinations, if any, is not expected to have a material adverse impact on PacifiCorp's consolidated financial results. Refer to Note 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's income taxes.

PacifiCorp is required to pass income tax benefits related to certain property-related basis differences and other various differences on to its customers in most state jurisdictions. These amounts were recognized as a net regulatory asset totaling \$426 million as of December 31, 2010 and will be included in rates when the temporary differences reverse. Management believes the existing net regulatory assets are probable of inclusion in rates. If it becomes no longer probable that these costs will be included in rates, the related regulatory asset will be charged to net income.

Revenue Recognition - Unbilled Revenue

Unbilled revenue was \$206 million as of December 31, 2010. Revenue is recognized as electricity is delivered or services are provided. The determination of customer billings is based on a systematic reading of meters. At the end of each month, amounts of energy provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns compared to normal, total volumes supplied to the system, line losses, economic impacts and composition of customer classes. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings. Historically, any differences between the actual and estimated amounts have been immaterial.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

PacifiCorp's Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. PacifiCorp's significant market risks are primarily associated with commodity prices, interest rates and the extension of credit to counterparties with which PacifiCorp transacts. The following sections address the significant market risks associated with PacifiCorp's business activities. PacifiCorp has also established guidelines for credit risk management. Refer to Notes 2 and 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's contracts accounted for as derivatives.

Risk Management

PacifiCorp has a risk management committee that is responsible for the oversight of market and credit risk relating to the commodity transactions of PacifiCorp. To limit PacifiCorp's exposure to market and credit risk, the risk management committee recommends, and executive management establishes, policies, limits and commodity strategies, which are reviewed frequently to respond to changing market conditions.

Risk is an inherent part of PacifiCorp's business and activities. PacifiCorp has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in PacifiCorp's business. To assist in managing the volatility relating to these exposures, PacifiCorp enters into various transactions, including derivative transactions, consistent with PacifiCorp's risk management policy and procedures. The risk management policy governs energy transactions and is designed for hedging PacifiCorp's existing energy and asset exposures, and to a limited extent, the policy permits arbitrage and trading activities to take advantage of market inefficiencies. The policy also governs the types of transactions authorized for use and establishes guidelines for credit risk management and management information systems required to effectively monitor such derivative use. PacifiCorp's risk management policy provides for the use of only those contracts that have a similar volume or price relationship to its portfolio of assets, liabilities or anticipated transactions. PacifiCorp does not engage in a material amount of proprietary trading activities.

Commodity Price Risk

PacifiCorp is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk as PacifiCorp has an obligation to serve retail customer load in its service territories. PacifiCorp's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather; market liquidity; generating facility availability; customer usage; storage; and transmission and transportation constraints. To mitigate a portion of its commodity price risk, PacifiCorp uses commodity contracts, which may be accounted for as derivatives, including forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. PacifiCorp does not hedge all of its commodity price risk, thereby exposing the unhedged portion to changes in market prices. PacifiCorp's exposure to commodity price risk is generally limited by its ability to include the costs in rates, which is subject to regulatory lag that occurs between the time the costs are incurred and when the costs are included in rates.

PacifiCorp measures the market risk in its electricity and natural gas portfolio daily, utilizing a historical Value-at-Risk ("VaR") approach and other measurements of net position. PacifiCorp also monitors its portfolio exposure to market risk in comparison to established thresholds and measures its open positions subject to price risk in terms of quantity at each delivery location for each forward time period. VaR computations for the electricity and natural gas commodity portfolio are based on a historical simulation technique, utilizing historical price changes over a specified (holding) period to simulate potential forward energy market price curve movements to estimate the potential unfavorable impact of such price changes on the portfolio positions. The quantification of market risk using VaR provides a consistent measure of risk across PacifiCorp's continually changing portfolio. VaR represents an estimate of possible changes at a given level of confidence in fair value that would be measured on its portfolio assuming hypothetical movements in forward market prices and is not necessarily indicative of actual results that may occur.

PacifiCorp's VaR computations utilize several key assumptions. The calculation includes short-term commodity contracts, the expected resource and demand obligations from PacifiCorp's long-term contracts, the expected generation levels from PacifiCorp's generation assets and the expected retail and wholesale load levels. The portfolio reflects flexibility contained in contracts and assets, which accommodate the normal variability in PacifiCorp's demand obligations and generation availability. These contracts and assets are valued to reflect the variability PacifiCorp experiences as a load-serving entity. Contracts or assets that contain flexible elements are often referred to as having embedded options or option characteristics. These options provide for energy volume changes that are sensitive to market price changes. Therefore, changes in the option values affect the energy position of the portfolio with respect to market prices, and this effect is calculated daily. When measuring portfolio exposure through VaR, these position changes that result from the option sensitivity are held constant through the historical simulation. PacifiCorp's VaR methodology is based on a 48-month forward position, 95% confidence interval and one-day holding period.

As of December 31, 2010, PacifiCorp's estimated potential one-day unfavorable impact on fair value of the electricity and natural gas commodity portfolio over the next 48 months was \$13 million, as measured by the VaR computations described above, compared to \$22 million as of December 31, 2009. The minimum, average and maximum daily VaR (one-day holding periods) were as follows for the years ended December 31 (in millions):

	2010	2009	2008
Minimum VaR (measured)	\$ 9	\$ 11	\$ 9
Average VaR (calculated)	12	18	14
Maximum VaR (measured)	23	23	23

PacifiCorp maintained compliance with its VaR limit procedures during the year ended December 31, 2010. Changes in markets inconsistent with historical trends or assumptions used could cause actual results to exceed predicted limits.

Fair Value of Derivatives

The following table shows summarized information with respect to valuation techniques and contractual maturities of PacifiCorp's energy-related contracts accounted for as derivatives as of December 31, 2010 (in millions):

	Fair Value of Contracts at Period-End				
	Maturity Less Than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity In Excess of 5 Years	Total Fair Value
Trading ⁽¹⁾ :					
Values based on quoted market prices from third-party sources	\$ 2	\$ —	\$ —	\$ —	\$ 2
Non-trading ⁽¹⁾ :					
Values based on quoted market prices from third-party sources	\$ 90	\$ (106)	\$ (4)	\$ —	\$ (20)
Values based on models and other valuation methods	(62)	(85)	(74)	(121)	(342)
Total non-trading	\$ 28	\$ (191)	\$ (78)	\$ (121)	\$ (362)
Net regulatory asset (liability)	\$ 56	\$ 232	\$ 78	\$ 121	\$ 487

(1) Net derivative assets (liabilities) include a net cash collateral receivable of \$127 million.

Standardized derivative contracts that are valued using market quotations are classified as "values based on quoted market prices from third-party sources." All remaining contracts, which include non-standard contracts and contracts for which market prices are not routinely quoted, are classified as "values based on models and other valuation methods." Both classifications utilize market curves as appropriate. PacifiCorp's valuation models are updated daily to reflect current market information, and evaluations and refinements of model assumptions are performed on a periodic basis.

The table that follows summarizes PacifiCorp's price risk on commodity contracts accounted for as derivatives, excluding collateral netting of \$127 million and \$25 million, as of December 31, 2010 and 2009, respectively, and shows the effects of a hypothetical 10% increase and a 10% decrease in forward market prices by the expected volumes for these contracts as of that date. The selected hypothetical change does not reflect what could be considered the best or worst case scenarios (dollars in millions).

	Fair Value - Asset (Liability)	Estimated Fair Value after Hypothetical Change in Price	
		10% increase	10% decrease
<u>As of December 31, 2010:</u>			
Not designated as hedging contracts	\$ (487)	\$ (465)	\$ (509)
Designated as hedging contracts	—	—	—
Total commodity derivative contracts	<u>\$ (487)</u>	<u>\$ (465)</u>	<u>\$ (509)</u>
<u>As of December 31, 2009:</u>			
Not designated as hedging contracts	\$ (369)	\$ (362)	\$ (376)
Designated as hedging contracts	—	—	—
Total commodity derivative contracts	<u>\$ (369)</u>	<u>\$ (362)</u>	<u>\$ (376)</u>

The majority of PacifiCorp's commodity derivative contracts not designated as hedging contracts are recoverable from customers in rates and, therefore, net unrealized gains and losses associated with interim price movements on commodity derivative contracts do not expose PacifiCorp to earnings volatility. As of December 31, 2010 and 2009, net regulatory assets of \$487 million and \$367 million, respectively, were recorded related to the net derivative liability of \$487 million and \$369 million, respectively. For PacifiCorp's commodity derivative contracts designated as hedging contracts, net unrealized gains and losses associated with interim price movements on commodity derivative contracts, to the extent the hedge is considered effective, generally do not expose PacifiCorp to earnings volatility. The settled cost of these commodity derivative contracts is generally included in rates. Consolidated financial results would be negatively impacted if the costs of wholesale electricity, natural gas or fuel are higher than what is included in rates, including the impacts of adjustment mechanisms.

Interest Rate Risk

PacifiCorp is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. PacifiCorp manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, PacifiCorp's fixed-rate long-term debt does not expose PacifiCorp to the risk of earnings loss due to changes in market interest rates and because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if PacifiCorp were to reacquire all or a portion of these instruments prior to their maturity. Additionally, PacifiCorp may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate PacifiCorp's exposure to interest rate risk. The nature and amount of PacifiCorp's short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 6, 8 and 9 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-K for additional discussion of PacifiCorp's short- and long-term debt.

As of December 31, 2010 and 2009, PacifiCorp had total short- and long-term variable-rate obligations totaling \$691 million and \$655 million, respectively, that expose PacifiCorp to the risk of increased interest expense in the event of increases in short-term interest rates. The market risk related to PacifiCorp's variable-rate debt as of December 31, 2010 is not hedged. If floating interest rates were to increase by 10% from December 31 levels, it would not have a material effect on PacifiCorp's annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2010 and 2009.

Credit Risk

PacifiCorp extends unsecured credit to other utilities, energy marketing companies, financial institutions and other market participants in conjunction with wholesale energy supply and marketing activities. Credit risk relates to the risk of loss that might occur as a result of nonperformance by counterparties on their contractual obligations to make or take delivery of electricity, natural gas or other commodities and to make financial settlements of these obligations. Credit risk may be concentrated to the extent that one or more groups of counterparties have similar economic, industry or other characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in market or other conditions. In addition, credit risk includes not only the risk that a counterparty may default due to circumstances relating directly to it, but also the risk that a counterparty may default due to circumstances involving other market participants that have a direct or indirect relationship with the counterparty.

PacifiCorp analyzes the financial condition of each significant wholesale counterparty before entering into any transactions, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To mitigate exposure to the financial risks of wholesale counterparties, PacifiCorp enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. Counterparties may be assessed interest fees for delayed payments. If required, PacifiCorp exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2010, PacifiCorp's aggregate credit exposure from wholesale activities totaled \$573 million, based on settlement and mark-to-market exposures, net of collateral. As of December 31, 2010, \$420 million, or 73%, of PacifiCorp's credit exposure was with counterparties having investment grade credit ratings by either Moody's Investor Service or Standard & Poor's Rating Services. As of December 31, 2010, \$5 million, or 1%, of such credit exposure was with counterparties having externally rated "non-investment grade" credit ratings, while \$148 million, or 26%, was with counterparties having financial characteristics deemed equivalent to "non-investment grade" by PacifiCorp based on internal review. As of December 31, 2010, four counterparties comprised \$365 million, or 64%, of the aggregate credit exposure. Three counterparties, which comprise \$267 million, are rated investment grade by Moody's Investor Service and Standard & Poor's Rating Services and PacifiCorp is not aware of any factors that would likely result in a downgrade of the counterparties' credit ratings to below investment grade over the remaining term of transactions outstanding as of December 31, 2010. The other counterparty has a non-investment grade credit rating based on internal review as of December 31, 2010.

Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
PacifiCorp
Portland, Oregon

We have audited the accompanying consolidated balance sheets of PacifiCorp and subsidiaries (the "Company") as of December 31, 2010 and 2009, and the related consolidated statements of operations, cash flows, changes in equity and comprehensive income for each of the three years in the period ended December 31, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes 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, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of PacifiCorp and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

/s/Deloitte & Touche LLP

Portland, Oregon
February 28, 2011

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2010	2009
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 31	\$ 117
Accounts receivable, net	628	619
Income taxes receivable from affiliates	345	249
Inventories:		
Materials and supplies	186	192
Fuel	188	187
Derivative contracts	114	108
Deferred income taxes	83	39
Other current assets	59	61
Total current assets	<u>1,634</u>	<u>1,572</u>
Property, plant and equipment, net	16,392	15,537
Regulatory assets	1,715	1,539
Derivative contracts	9	43
Investments and other assets	396	275
Total assets	<u>\$ 20,146</u>	<u>\$ 18,966</u>

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

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2010	2009
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	\$ 479	\$ 553
Accrued employee expenses	81	76
Accrued interest	110	111
Accrued property and other taxes	63	67
Derivative contracts	84	85
Short-term debt	36	—
Current portion of long-term debt and capital lease obligations	588	16
Other current liabilities	97	105
Total current liabilities	<u>1,538</u>	<u>1,013</u>
Regulatory liabilities	849	838
Derivative contracts	399	410
Long-term debt and capital lease obligations	5,813	6,400
Deferred income taxes	3,448	2,625
Other long-term liabilities	788	948
Total liabilities	<u>12,835</u>	<u>12,234</u>
Commitments and contingencies (Note 13)		
Equity:		
PacifiCorp shareholders' equity:		
Preferred stock	41	41
Common equity:		
Common stock - 750 shares authorized, no par value, 357 shares issued and outstanding	—	—
Additional paid-in capital	4,479	4,379
Retained earnings	2,798	2,234
Accumulated other comprehensive loss, net	(7)	(6)
Total common equity	<u>7,270</u>	<u>6,607</u>
Total PacifiCorp shareholders' equity	<u>7,311</u>	<u>6,648</u>
Noncontrolling interest	—	84
Total equity	<u>7,311</u>	<u>6,732</u>
Total liabilities and equity	<u>\$ 20,146</u>	<u>\$ 18,966</u>

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

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2010	2009	2008
Operating revenue	\$ 4,432	\$ 4,457	\$ 4,498
Operating costs and expenses:			
Energy costs	1,618	1,677	1,957
Operations and maintenance	1,081	1,035	985
Depreciation and amortization	561	549	490
Taxes, other than income taxes	136	136	112
Total operating costs and expenses	3,396	3,397	3,544
Operating income	1,036	1,060	954
Other income (expense):			
Interest expense	(387)	(394)	(343)
Allowance for borrowed funds	45	35	34
Allowance for equity funds	79	64	47
Interest income	5	19	11
Other, net	(1)	—	—
Total other income (expense)	(259)	(276)	(251)
Income before income tax expense	777	784	703
Income tax expense	211	234	238
Net income	566	550	465
Net income attributable to noncontrolling interest	—	8	7
Net income attributable to PacifiCorp	\$ 566	\$ 542	\$ 458

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

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2010	2009	2008
Cash flows from operating activities:			
Net income	\$ 566	\$ 550	\$ 465
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	561	549	490
Provision for deferred income taxes	710	645	308
Changes in regulatory assets and liabilities	4	5	(37)
Other, net	(58)	(32)	(10)
Changes in other operating assets and liabilities, net of effects from acquisition:			
Accounts receivable and other assets	(14)	(5)	3
Derivative collateral, net	(102)	57	(82)
Inventories	(26)	(39)	(52)
Income taxes - affiliates, net	(96)	(206)	(20)
Accounts payable and other liabilities	(135)	(24)	(73)
Net cash flows from operating activities	<u>1,410</u>	<u>1,500</u>	<u>992</u>
Cash flows from investing activities:			
Capital expenditures	(1,607)	(2,328)	(1,789)
Acquisition, net of cash acquired	—	—	(308)
Purchases of available-for-sale securities	—	(21)	(52)
Proceeds from sales of available-for-sale securities	—	36	67
Other, net	(6)	5	6
Net cash flows from investing activities	<u>(1,613)</u>	<u>(2,308)</u>	<u>(2,076)</u>
Cash flows from financing activities:			
Net proceeds from (repayments of) short-term debt	36	(85)	85
Proceeds from long-term debt	—	992	797
Proceeds from previously reacquired long-term debt	—	—	216
Proceeds from equity contributions	100	125	450
Reacquired long-term debt	—	—	(216)
Repayments and redemptions of long-term debt and capital lease obligations	(16)	(144)	(413)
Preferred stock dividends	(2)	(2)	(2)
Other, net	(1)	(20)	(2)
Net cash flows from financing activities	<u>117</u>	<u>866</u>	<u>915</u>
Net change in cash and cash equivalents	<u>(86)</u>	<u>58</u>	<u>(169)</u>
Cash and cash equivalents at beginning of period	<u>117</u>	<u>59</u>	<u>228</u>
Cash and cash equivalents at end of period	<u>\$ 31</u>	<u>\$ 117</u>	<u>\$ 59</u>

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

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Amounts in millions)

PacifiCorp Shareholders' Equity							
	Preferred Stock	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Noncontrolling Interest	Total Equity
Balance, January 1, 2008	\$ 41	\$ —	\$ 3,804	\$ 1,239	\$ (4)	\$ 79	\$ 5,159
Net income	—	—	—	458	—	7	465
Other comprehensive income	—	—	—	—	2	—	2
Contributions	—	—	450	—	—	45	495
Distributions	—	—	—	—	—	(42)	(42)
Preferred stock dividends declared	—	—	—	(2)	—	—	(2)
Other equity transactions	—	—	—	(1)	—	(9)	(10)
Balance, December 31, 2008	41	—	4,254	1,694	(2)	80	6,067
Net income	—	—	—	542	—	8	550
Other comprehensive loss	—	—	—	—	(4)	—	(4)
Contributions	—	—	125	—	—	28	153
Distributions	—	—	—	—	—	(38)	(38)
Preferred stock dividends declared	—	—	—	(2)	—	—	(2)
Other equity transactions	—	—	—	—	—	6	6
Balance, December 31, 2009	41	—	4,379	2,234	(6)	84	6,732
Deconsolidation of Bridger Coal	—	—	—	—	—	(84)	(84)
Net income	—	—	—	566	—	—	566
Other comprehensive loss	—	—	—	—	(1)	—	(1)
Contributions	—	—	100	—	—	—	100
Preferred stock dividends declared	—	—	—	(2)	—	—	(2)
Balance, December 31, 2010	\$ 41	\$ —	\$ 4,479	\$ 2,798	\$ (7)	\$ —	\$ 7,311

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

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2010	2009	2008
Net income	\$ 566	\$ 550	\$ 465
Other comprehensive income (loss), net of tax:			
Unrecognized amounts on retirement benefits, net of tax of \$(1), \$(1) and \$-	(1)	(4)	2
Comprehensive income	565	546	467
Comprehensive income attributable to noncontrolling interest	—	8	7
Comprehensive income attributable to PacifiCorp	<u>\$ 565</u>	<u>\$ 538</u>	<u>\$ 460</u>

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

PACIFICORP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Operations

PacifiCorp, which includes PacifiCorp and its subsidiaries, is a United States regulated electric company serving 1.7 million retail customers, including residential, commercial, industrial and other customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp owns, or has interests in, a number of thermal, hydroelectric, wind-powered and geothermal generating facilities, as well as electric transmission and distribution assets. PacifiCorp also buys and sells electricity on the wholesale market with public and private utilities, energy marketing companies and incorporated municipalities. PacifiCorp is subject to comprehensive state and federal regulation. PacifiCorp's subsidiaries support its electric utility operations by providing coal mining and environmental remediation services. PacifiCorp is an indirect subsidiary of MidAmerican Energy Holdings Company ("MEHC"), a holding company based in Des Moines, Iowa that owns subsidiaries principally engaged in energy businesses. MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of PacifiCorp and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. Intercompany accounts and transactions have been eliminated.

Use of Estimates in Preparation of Financial Statements

The preparation of the Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; effects of regulation; accounting for contingencies, including environmental and regulatory matters; income taxes; asset retirement obligations ("AROs"); and certain assumptions made in accounting for pension and other postretirement benefits. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

Accounting for the Effects of Certain Types of Regulation

PacifiCorp prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, PacifiCorp is required to defer the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future rates.

PacifiCorp continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition which could limit PacifiCorp's ability to recover its costs. Based upon this continuous evaluation, PacifiCorp believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels and is subject to change in the future. If it becomes no longer probable that the deferred costs or income will be included in future rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income.

Fair Value Measurements

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Different valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered when determining the fair value of assets and liabilities. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

Cash Equivalents and Restricted Cash and Investments

Cash equivalents consist of funds invested in United States Treasury Bills, money market funds and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted amounts are included in other current assets and investments and other assets on the Consolidated Balance Sheets.

Investments

PacifiCorp's management determines the appropriate classifications of investments in debt and equity securities at the acquisition date and reevaluates the classifications at each balance sheet date. Investments that management does not intend to use in current operations are presented as noncurrent on the Consolidated Balance Sheets.

Available-for-sale securities are carried at fair value with realized gains and losses, as determined on a specific identification basis, recognized in earnings and unrealized gains and losses recognized in accumulated other comprehensive income (loss) ("AOCI"), net of tax.

If in management's judgment a decline in the fair value of an available-for-sale investment below cost is other than temporary, the cost of the investment is written down to fair value. Factors considered in judging whether an impairment is other than temporary include: the financial condition, business prospects and creditworthiness of the issuer; the length of time that fair value has been less than cost; the relative amount of the decline; and PacifiCorp's ability and intent to hold the investment until the fair value recovers. Impairment losses on equity securities are charged to earnings. With respect to an investment in a debt security, any resulting impairment loss is recognized in earnings if PacifiCorp intends to sell or expects to be required to sell the debt security before amortized cost is recovered. If PacifiCorp does not expect to ultimately recover the amortized cost basis, even if it does not intend to sell the security, the credit loss component is recognized in earnings and any difference between fair value and the amortized cost basis, net of the credit loss, is reflected in other comprehensive income (loss) ("OCI"). To the extent recovery in rates is probable, any impairment charge would be offset by the establishment of a regulatory asset.

PacifiCorp utilizes the equity method of accounting with respect to investments when it possesses the ability to exercise significant influence, but not control, over the operating and financial policies of the investee. The ability to exercise significant influence is presumed when an investor possesses more than 20% of the voting interests of the investee. This presumption may be overcome based on specific facts and circumstances that demonstrate that the ability to exercise significant influence is restricted. In applying the equity method, PacifiCorp records the investment at cost and subsequently increases or decreases the carrying amount of the investment by PacifiCorp's proportionate share of the net earnings or losses and OCI of the investee. PacifiCorp records dividends or other equity distributions as reductions in the carrying value of the investment.

Allowance for Doubtful Accounts

Accounts receivable are stated at the outstanding principal amount, net of estimated allowances for doubtful accounts. The allowance for doubtful accounts is based on PacifiCorp's assessment of the collectibility of amounts owed to PacifiCorp by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. The change in the balance of the allowance for doubtful accounts, which is included in accounts receivable, net on the Consolidated Balance Sheets is summarized as follows for the years ended December 31 (in millions):

	<u>2010</u>	<u>2009</u>	<u>2008</u>
Beginning balance	\$ 7	\$ 9	\$ 7
Charged to operating costs and expenses, net	12	12	14
Write-offs, net	(11)	(14)	(12)
Ending balance	<u>\$ 8</u>	<u>\$ 7</u>	<u>\$ 9</u>

Derivatives

PacifiCorp employs a number of different derivative contracts, including forwards, futures, options, swaps and other agreements, to manage price risk for electricity, natural gas and other commodities and interest rate risk. Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting permitted under master netting arrangements with counterparties and cash collateral paid or received under such agreements.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases and normal sales. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as operating revenue or energy costs on the Consolidated Statements of Operations.

For PacifiCorp's derivatives designated as hedging contracts, PacifiCorp formally assesses, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. PacifiCorp formally documents hedging activity by transaction type and risk management strategy.

Changes in the estimated fair value of a derivative contract designated and qualified as a cash flow hedge, to the extent effective, are included on the Consolidated Statements of Changes in Equity as AOCI, net of tax, until the contract settles and the hedged item is recognized in earnings. PacifiCorp discontinues hedge accounting prospectively when it has determined that a derivative contract no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative contract no longer qualifies as an effective hedge, future changes in the estimated fair value of the derivative contract are charged to earnings. Gains and losses related to discontinued hedges that were previously recorded in AOCI will remain in AOCI until the contract settles and the hedged item is recognized in earnings, unless it becomes probable that the hedged forecasted transaction will not occur at which time associated deferred amounts in AOCI will be immediately recognized in earnings.

For PacifiCorp's derivatives not designated as hedging contracts, the settled amount is generally included in rates. Accordingly, changes in the fair value of a derivative contract that are probable of inclusion in rates are recorded as net regulatory assets. For a derivative contract not probable of inclusion in rates and not designated as a hedging contract, changes in the fair value are recognized in earnings.

Inventories

Inventories consist of materials and supplies, coal stocks, natural gas and fuel oil, which are stated at the lower of average cost or market.

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. PacifiCorp capitalizes all construction related material, direct labor and contract services, as well as indirect construction costs, which include debt and equity allowance for funds used during construction ("AFUDC"). The cost of major additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed.

Depreciation and amortization are generally computed by applying the composite or straight-line method based on either estimated useful lives or mandated recovery periods as prescribed by PacifiCorp's various regulatory authorities. Depreciation studies are completed to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the various regulatory authorities. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as either a cost of removal regulatory liability or an ARO liability on the Consolidated Balance Sheets, depending on whether the obligation meets the requirements of an ARO. As actual removal costs are incurred, the associated liability is reduced.

Generally when PacifiCorp retires or sells a component of regulated property, plant and equipment, it charges the original cost and any net proceeds from the disposition to accumulated depreciation. Any gain or loss on disposals of all other assets is recorded through earnings.

PacifiCorp records debt and equity AFUDC, which represents the estimated costs of debt and equity funds necessary to finance additions to property, plant and equipment. AFUDC is capitalized as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. After construction is completed, PacifiCorp is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets.

Asset Retirement Obligations

PacifiCorp recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. PacifiCorp's AROs are primarily associated with its generating facilities. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to property, plant and equipment) and for accretion of the ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability.

Revenue Recognition

Revenue is recognized as electricity is delivered or services are provided. Revenue recognized includes unbilled, as well as billed, amounts. As of December 31, 2010 and 2009, unbilled revenue was \$206 million and \$214 million, respectively, and is included in accounts receivable, net on the Consolidated Balance Sheets. Rates charged are established by regulators or contractual arrangements.

The determination of sales to individual customers is based on the reading of the customer's meter, which is performed on a systematic basis throughout the month. At the end of each month, amounts of energy provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. The estimate is reversed in the following month and actual revenue is recorded based on subsequent meter readings.

The monthly unbilled revenues of PacifiCorp are determined by the estimation of unbilled energy provided during the period, the assignment of unbilled energy provided to customer classes and the average rate per customer class. Factors that can impact the estimate of unbilled energy provided include, but are not limited to, seasonal weather patterns, customer usage patterns, historical trends, volumes, line losses, retail rate changes and composition of customer classes.

PacifiCorp records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Consolidated Statements of Operations.

Income Taxes

Berkshire Hathaway includes PacifiCorp in its United States federal income tax return. Consistent with established regulatory practice, PacifiCorp's provision for income taxes has been computed on a stand-alone basis.

Deferred tax assets and liabilities are based on differences between the financial statement and tax basis of assets and liabilities using estimated tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities that are associated with components of OCI are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities that are associated with income tax benefits related to certain property-related basis differences and other various differences that PacifiCorp is required to pass on to its customers in most state jurisdictions are charged or credited directly to a regulatory asset or liability. These amounts were recognized as a net regulatory asset totaling \$426 million and \$401 million as of December 31, 2010 and 2009, respectively, and will be included in rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense.

Investment tax credits are generally deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory jurisdictions. Investment tax credits are included in other long-term liabilities on the Consolidated Balance Sheets and were \$42 million and \$46 million as of December 31, 2010 and 2009, respectively.

In determining PacifiCorp's income taxes, management is required to interpret complex tax laws and regulations, which includes consideration of regulatory implications imposed by PacifiCorp's various regulatory jurisdictions. PacifiCorp's tax returns are subject to continuous examinations by federal, state and local tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. PacifiCorp recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. Although the ultimate resolution of PacifiCorp's federal, state and local tax examinations is uncertain, PacifiCorp believes it has made adequate provisions for these tax positions. The aggregate amount of any additional tax liabilities that may result from these examinations, if any, is not expected to have a material adverse effect on PacifiCorp's consolidated financial results. PacifiCorp's unrecognized tax benefits are primarily included in accrued property and other taxes and other long-term liabilities on the Consolidated Balance Sheets. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense on the Consolidated Statements of Operations.

Segment Information

PacifiCorp currently has one segment, which includes its regulated electric utility operations.

New Accounting Pronouncements

In January 2010, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2010-06 ("ASU No. 2010-06"), which amends FASB Accounting Standards Codification ("ASC") Topic 820, "Fair Value Measurements and Disclosures." ASU No. 2010-06 requires disclosure of (a) the amount of significant transfers into and out of Levels 1 and 2 of the fair value hierarchy and the reasons for those transfers and (b) gross presentation of purchases, sales, issuances and settlements in the Level 3 fair value measurement rollforward. This guidance clarifies that existing fair value measurement disclosures should be presented for each class of assets and liabilities. The existing disclosures about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements have also been clarified to ensure such disclosures are presented for the Levels 2 and 3 fair value measurements. PacifiCorp adopted this guidance as of January 1, 2010, with the exception of the disclosure requirement to present purchases, sales, issuances and settlements gross in the Level 3 fair value measurement rollforward, which is effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. The adoption did not have a material impact on PacifiCorp's disclosures included within Notes to Consolidated Financial Statements.

In June 2009, the FASB issued authoritative guidance (which was codified into ASC Topic 810, "Consolidation" with the issuance of ASU No. 2009-17) that requires a primarily qualitative analysis to determine if an enterprise is the primary beneficiary of a variable interest entity. This analysis is based on whether the enterprise has (a) the power to direct the activities of the variable interest entity that most significantly impact the entity's economic performance and (b) the obligation to absorb losses of the entity or the right to receive benefits from the entity that could potentially be significant to the variable interest entity. In addition, enterprises are required to more frequently reassess whether an entity is a variable interest entity and whether the enterprise is the primary beneficiary of the variable interest entity. Finally, the guidance for consolidation or deconsolidation of a variable interest entity is amended and disclosure requirements about an enterprise's involvement with a variable interest entity are enhanced. PacifiCorp adopted this guidance as of January 1, 2010 on a prospective basis. As a result, PacifiCorp's coal mining joint venture, Bridger Coal Company ("Bridger Coal") was deconsolidated and is being accounted for under the equity method of accounting as the power to direct the activities that most significantly impact Bridger Coal's economic performance are shared with the joint venture partner. The deconsolidation of Bridger Coal resulted in a decrease in assets, liabilities and noncontrolling interest equity as of January 1, 2010 of \$192 million, \$108 million and \$84 million, respectively. These changes included the deconsolidation of: (a) mine reclamation trust funds totaling \$79 million; (b) property, plant and equipment, net totaling \$249 million; and (c) asset retirement obligation liabilities totaling \$79 million. Additionally, as a result of PacifiCorp's investment in Bridger Coal being accounted for under the equity method, an investment of \$168 million was recorded on January 1, 2010.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciable Life	2010	2009
Property, plant and equipment:			
Generation	15 - 80 years	\$ 9,901	\$ 9,022
Transmission	25 - 75 years	4,335	3,346
Distribution	44 - 52 years	5,491	5,332
Intangible plant ⁽¹⁾	5 - 53 years	848	752
Other	5 - 43 years	1,459	1,878
Property, plant and equipment in service		22,034	20,330
Accumulated depreciation and amortization		(6,646)	(6,623)
Net property, plant and equipment in service		15,388	13,707
Construction work-in-progress		1,004	1,830
Total property, plant and equipment, net		\$ 16,392	\$ 15,537

(1) Computer software costs included in intangible plant are initially assigned a depreciable life of 5 to 10 years.

Unallocated Acquisition Adjustments

PacifiCorp has unallocated acquisition adjustments that represent the excess of costs of the acquired interests in property, plant and equipment purchased from the entity that first devoted the assets to utility service over their net book value in those assets. These unallocated acquisition adjustments included in other property, plant and equipment had an original cost of \$159 million and \$157 million as of December 31, 2010 and 2009, respectively, and accumulated depreciation of \$102 million and \$96 million as of December 31, 2010 and 2009, respectively.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements with other utilities, PacifiCorp, as a tenant in common, has undivided interests in jointly owned generation, transmission and distribution facilities and transmission lines. PacifiCorp accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each generating facility or transmission line. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Consolidated Statements of Operations include PacifiCorp's share of the expenses of these facilities.

The amounts shown in the table below represent PacifiCorp's share in each jointly owned facility as of December 31, 2010 (dollars in millions):

	<u>PacifiCorp Share</u>	<u>Facility in Service</u>	<u>Accumulated Depreciation and Amortization</u>	<u>Construction Work-in- Progress</u>
Jim Bridger Nos. 1 - 4 ⁽¹⁾	67%	\$ 1,077	\$ 492	\$ 29
Hunter No. 1	94	348	149	21
Wyodak ⁽¹⁾	80	341	184	85
Colstrip Nos. 3 and 4 ⁽¹⁾	10	247	126	2
Hunter No. 2	60	193	93	77
Hermiston ⁽²⁾	50	175	50	1
Craig Nos. 1 and 2	19	170	87	4
Hayden No. 1	25	46	25	5
Foote Creek	79	37	17	—
Hayden No. 2	13	28	16	3
Other transmission and distribution facilities	Various	181	21	11
Total		<u>\$ 2,843</u>	<u>\$ 1,260</u>	<u>\$ 238</u>

(1) Includes transmission lines and substations.

(2) PacifiCorp has contracted to purchase the remaining 50% of the output of the Hermiston generating facility.

(5) Regulatory Matters

Regulatory Assets and Liabilities

Regulatory assets represent costs that are expected to be recovered in future rates. PacifiCorp's regulatory assets reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2010	2009
Employee benefit plans ⁽¹⁾	9 years	\$ 595	\$ 576
Unrealized loss on regulated derivative contracts	4 years	487	367
Deferred income taxes ⁽²⁾	33 years	448	422
Other	Various	185	174
Total		<u>\$ 1,715</u>	<u>\$ 1,539</u>

(1) Substantially represents amounts not yet recognized as a component of net periodic benefit cost that are expected to be included in rates when recognized. Amounts are partially offset by \$12 million and \$19 million of the unamortized portion of net regulatory deferrals related to curtailment gains and the measurement date change transitional adjustment as of December 31, 2010 and 2009, respectively.

(2) Amounts primarily represent income tax benefits related to state accelerated tax depreciation and certain property-related basis differences that were previously flowed through to customers and will be included in rates when the temporary differences reverse.

PacifiCorp had regulatory assets not earning a return on investment of \$1.575 billion and \$1.385 billion as of December 31, 2010 and 2009, respectively.

Regulatory liabilities represent income to be recognized or amounts to be returned to customers in future periods. PacifiCorp's regulatory liabilities reflected on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2010	2009
Cost of removal ⁽¹⁾	33 years	\$ 782	\$ 755
Deferred income taxes	Various	22	21
Other	Various	45	62
Total		<u>\$ 849</u>	<u>\$ 838</u>

(1) Amounts represent estimated costs, as accrued through depreciation rates and exclusive of ARO liabilities, of removing property, plant and equipment in accordance with accepted regulatory practices. Amounts are deducted from rate base or otherwise accrue a carrying cost.

Rate Matters

Oregon Senate Bill 408

Oregon Senate Bill 408 ("SB 408") requires PacifiCorp and other large regulated, investor-owned utilities that provide electric or natural gas service to Oregon customers to file an annual report each October with the Oregon Public Utilities Commission ("OPUC") comparing income taxes collected and income taxes paid, as defined by the statute and its administrative rules. If after its review, the OPUC determines the amount of income taxes collected differs from the amount of income taxes paid by more than \$100,000, the OPUC must require the public utility to establish an automatic adjustment clause to account for the difference.

The OPUC issued an order in April 2008 approving the recovery of \$35 million, plus interest, related to PacifiCorp's 2006 tax report. This order was challenged by the Industrial Customers of Northwest Utilities ("ICNU"), which petitioned the Oregon Court of Appeals for judicial review of, among other things, the application of certain administrative rules considered in the April 2008 order. In December 2010, the Oregon Court of Appeals affirmed the OPUC's April 2008 order. The ICNU did not seek further judicial review of the order, and the order is now final. The \$35 million, plus interest, was previously recorded and collected from customers.

In October 2009, PacifiCorp filed for a surcharge of \$38 million in its 2008 tax report under SB 408. In January 2010, PacifiCorp entered into a stipulation with OPUC staff and the Citizens' Utility Board of Oregon ("CUB"), agreeing to a lower surcharge totaling \$2 million, including interest. In April 2010, the OPUC issued an order adopting the stipulation in its entirety, at which time PacifiCorp recorded the \$2 million in operating revenue.

In October 2010, PacifiCorp filed for a surcharge of \$29 million, plus interest, in its 2009 tax report under SB 408. In January 2011, PacifiCorp entered into a two-part stipulation with the OPUC staff and the CUB, whereby; (a) PacifiCorp, the OPUC staff and the CUB agreed to a surcharge of \$13 million, plus interest as a result of a proposed rule change by the OPUC; and (b) the OPUC staff agreed to support PacifiCorp's request to defer an additional \$14 million pending the adoption of the revised rules by the OPUC that are consistent with the normalization requirements of the Internal Revenue Code. No amounts have been recorded in relation to the 2009 tax report.

(6) Fair Value Measurements

The carrying value of PacifiCorp's cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. PacifiCorp has various financial assets and liabilities that are measured at fair value on the Consolidated Financial Statements using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 - Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that PacifiCorp has the ability to access at the measurement date.
- Level 2 - Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 - Unobservable inputs reflect PacifiCorp's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. PacifiCorp develops these inputs based on the best information available, including its own data.

The following table presents PacifiCorp's assets and liabilities recognized on the Consolidated Balance Sheets and measured at fair value on a recurring basis (in millions):

	Input Levels for Fair Value Measurements				
	Level 1	Level 2	Level 3	Other ⁽¹⁾	Total
As of December 31, 2010					
Assets:					
Commodity derivatives	\$ —	\$ 263	\$ 5	\$ (145)	\$ 123
Investments in available-for-sale securities - Money market funds ⁽²⁾	29	—	—	—	29
	<u>\$ 29</u>	<u>\$ 263</u>	<u>\$ 5</u>	<u>\$ (145)</u>	<u>\$ 152</u>
Liabilities:					
Commodity derivatives	<u>\$ —</u>	<u>\$ (405)</u>	<u>\$ (350)</u>	<u>\$ 272</u>	<u>\$ (483)</u>
As of December 31, 2009					
Assets:					
Commodity derivatives	\$ —	\$ 285	\$ 6	\$ (140)	\$ 151
Investments in available-for-sale securities: Money market funds ⁽²⁾	123	—	—	—	123
Debt securities	1	33	—	—	34
Equity securities	36	8	—	—	44
	<u>\$ 160</u>	<u>\$ 326</u>	<u>\$ 6</u>	<u>\$ (140)</u>	<u>\$ 352</u>
Liabilities:					
Commodity derivatives	<u>\$ —</u>	<u>\$ (274)</u>	<u>\$ (386)</u>	<u>\$ 165</u>	<u>\$ (495)</u>

(1) Represents netting under master netting arrangements and a net cash collateral receivable of \$127 million and \$25 million as of December 31, 2010 and 2009, respectively.

(2) Amounts are included in cash and cash equivalents, other current assets and investments and other assets on the Consolidated Balance Sheets. The fair value of these money market mutual funds approximates cost.

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which PacifiCorp transacts. When quoted prices for identical contracts are not available, PacifiCorp uses forward price curves. Forward price curves represent PacifiCorp's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. PacifiCorp bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent energy brokers, exchanges, direct communication with market participants and actual transactions executed by PacifiCorp. Market price quotations for certain major electricity and natural gas trading hubs are generally readily obtainable for the first six years; therefore, PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. Market price quotations for other electricity and natural gas trading hubs are not as readily obtainable for the first six years. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, PacifiCorp uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on significant unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts. Refer to Note 7 for further discussion regarding PacifiCorp's risk management and hedging activities.

Contracts with explicit or embedded optionality are valued by separating each contract into its physical and financial forward, swap and option components. Forward and swap components are valued against the appropriate forward price curve. Option components are valued using Black-Scholes-type models, such as European option, Asian option, spread option and best-of option, with the appropriate forward price curve and other inputs.

PacifiCorp's investments in money market mutual funds and debt and equity securities are accounted for as available-for-sale securities and are stated at fair value. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics.

The following table reconciles the beginning and ending balances of PacifiCorp's commodity derivative assets and liabilities measured at fair value on a recurring basis using significant Level 3 inputs for the years ended December 31 (in millions):

	2010	2009
Beginning balance	\$ (380)	\$ (408)
Changes in fair value recognized in regulatory assets	(38)	(5)
Purchases, sales, issuances and settlements	73	56
Net transfers (to) from Level 2	—	(23)
Ending balance	<u>\$ (345)</u>	<u>\$ (380)</u>

PacifiCorp's long-term debt is carried at cost on the Consolidated Financial Statements. The fair value of PacifiCorp's long-term debt has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of PacifiCorp's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of PacifiCorp's long-term debt as of December 31 (in millions):

	2010		2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	<u>\$ 6,344</u>	<u>\$ 7,086</u>	<u>\$ 6,357</u>	<u>\$ 6,843</u>

(7) Risk Management and Hedging Activities

PacifiCorp is exposed to the impact of market fluctuations in commodity prices and interest rates. PacifiCorp is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk as it has an obligation to serve retail customer load in its regulated service territories. PacifiCorp's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather; market liquidity; generating facility availability; customer usage; storage; and transmission and transportation constraints. Interest rate risk exists on variable-rate short- and long-term debt and future debt issuances. PacifiCorp does not engage in a material amount of proprietary trading activities.

PacifiCorp has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business. To mitigate a portion of its commodity risk, PacifiCorp uses commodity derivative contracts, including forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. PacifiCorp manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. PacifiCorp may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate PacifiCorp's exposure to interest rate risk. No interest rate derivatives were in place during the periods presented. PacifiCorp does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in PacifiCorp's accounting policies related to derivatives. Refer to Notes 2 and 6 for additional information on derivative contracts.

The following table, which excludes contracts that qualify for the normal purchases or normal sales exception afforded by GAAP, summarizes the fair value of PacifiCorp's derivative contracts, on a gross basis, and reconciles those amounts to the amounts presented on a net basis on the Consolidated Balance Sheets (in millions):

	Derivative Assets		Derivative Liabilities		
	Current	Noncurrent	Current	Noncurrent	Total
As of December 31, 2010					
Not designated as hedging contracts⁽¹⁾⁽²⁾:					
Commodity assets	\$ 185	\$ 13	\$ 34	\$ 36	\$ 268
Commodity liabilities	(62)	(4)	(213)	(476)	(755)
Total	123	9	(179)	(440)	(487)
Designated as cash flow hedging contracts⁽¹⁾:					
Commodity assets	—	—	—	—	—
Commodity liabilities	—	—	—	—	—
Total	—	—	—	—	—
Total derivatives	123	9	(179)	(440)	(487)
Cash collateral (payable) receivable	(9)	—	95	41	127
Total derivatives - net basis	\$ 114	\$ 9	\$ (84)	\$ (399)	\$ (360)
As of December 31, 2009					
Not designated as hedging contracts⁽¹⁾⁽²⁾:					
Commodity assets	\$ 191	\$ 61	\$ 8	\$ 31	\$ 291
Commodity liabilities	(29)	(17)	(142)	(472)	(660)
Total	162	44	(134)	(441)	(369)
Designated as cash flow hedging contracts⁽¹⁾:					
Commodity assets	—	—	—	—	—
Commodity liabilities	—	—	—	—	—
Total	—	—	—	—	—
Total derivatives	162	44	(134)	(441)	(369)
Cash collateral (payable) receivable	(54)	(1)	49	31	25
Total derivatives - net basis	\$ 108	\$ 43	\$ (85)	\$ (410)	\$ (344)

(1) Derivative contracts within these categories subject to master netting arrangements are presented on a net basis on the Consolidated Balance Sheets.

(2) PacifiCorp's commodity derivatives not designated as hedging contracts are generally included in rates and as of December 31, 2010 and 2009, a net regulatory asset of \$487 million and \$367 million, respectively, was recorded related to the net derivative liability of \$487 million and \$369 million, respectively.

Not Designated as Hedging Contracts

For PacifiCorp's commodity derivatives not designated as hedging contracts, the settled amount is generally included in rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in rates are recorded as net regulatory assets. The following table reconciles the beginning and ending balances of PacifiCorp's net regulatory assets and summarizes the pre-tax gains and losses on commodity derivative contracts recognized in net regulatory assets, as well as amounts reclassified to earnings for the years ended December 31 (in millions):

	2010	2009
Beginning balance	\$ 367	\$ 442
Changes in fair value recognized in net regulatory assets	90	(74)
Net gains reclassified to earnings - operating revenue	64	222
Net losses reclassified to earnings - energy costs	(34)	(223)
Ending balance	\$ 487	\$ 367

For PacifiCorp's derivatives not designated as hedging contracts and for which changes in fair value are not recorded as a net regulatory asset or liability, unrealized gains and losses are recognized on the Consolidated Statements of Operations as operating revenue for sales contracts and energy costs and operations and maintenance for purchase contracts and electricity, natural gas and fuel oil swap contracts. The following table summarizes the pre-tax gains (losses) included on the Consolidated Statements of Operations associated with PacifiCorp's derivative contracts not designated as hedging contracts and not recorded as a net regulatory asset for the years ended December 31 (in millions):

	2010	2009
Commodity derivatives:		
Operating revenue	\$ 2	\$ 5
Energy costs	(2)	1
Total	<u>\$ —</u>	<u>\$ 6</u>

Designated as Hedging Contracts

PacifiCorp uses derivative contracts accounted for as cash flow hedges to hedge electricity and natural gas commodity prices. The following table reconciles the beginning and ending balances of PacifiCorp's AOCI (pre-tax) and summarizes pre-tax gains and losses on commodity derivative contracts designated and qualifying as cash flow hedges recognized in OCI, as well as amounts reclassified to earnings for the years ended December 31 (in millions):

	2010	2009
Beginning balance	\$ —	\$ —
Net (gains) losses recognized in OCI	(12)	2
Net losses reclassified to earnings - revenue	(1)	(2)
Net gains reclassified to earnings - energy costs	13	—
Ending balance	<u>\$ —</u>	<u>\$ —</u>

Realized gains and losses on hedges and hedge ineffectiveness are recognized in income as operating revenue or energy costs depending upon the nature of the item being hedged. For the years ended December 31, 2010, 2009 and 2008, hedge ineffectiveness was insignificant. As of December 31, 2010 and 2009, PacifiCorp had no cash flow hedges outstanding.

Derivative Contract Volumes

The following table summarizes the net notional amounts of outstanding derivative contracts with fixed price terms that comprise the mark-to-market values as of December 31 (in millions):

	Unit of Measure	2010	2009
Commodity contracts:			
Electricity sales	Megawatt hours	(13)	(22)
Natural gas purchases	Decatherms	159	201
Fuel oil purchases	Gallons	16	14

Credit Risk

PacifiCorp extends unsecured credit to other utilities, energy marketing companies, financial institutions and other market participants in conjunction with wholesale sales and purchases activities. Credit risk relates to the risk of loss that might occur as a result of nonperformance by counterparties on their contractual obligations to make or take delivery of electricity, natural gas or other commodities and to make financial settlements of these obligations. Credit risk may be concentrated to the extent that one or more groups of counterparties have similar economic, industry or other characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in market or other conditions. In addition, credit risk includes not only the risk that a counterparty may default due to circumstances relating directly to it, but also the risk that a counterparty may default due to circumstances involving other market participants that have a direct or indirect relationship with the counterparty.

PacifiCorp analyzes the financial condition of each significant wholesale counterparty before entering into any transactions, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To mitigate exposure to the financial risks of wholesale counterparties, PacifiCorp enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. Counterparties may be assessed interest fees for delayed payments. If required, PacifiCorp exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Collateral and Contingent Features

In accordance with industry practice, certain derivative contracts contain provisions that require PacifiCorp to maintain specific credit ratings from one or more of the major credit rating agencies on its unsecured debt. These derivative contracts may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" in the event of a material adverse change in PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2010, PacifiCorp's credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of PacifiCorp's derivative contracts in liability positions with specific credit-risk-related contingent features totaled \$448 million and \$353 million as of December 31, 2010 and 2009, respectively, for which PacifiCorp had posted collateral of \$136 million and \$80 million, respectively. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of December 31, 2010 and 2009, PacifiCorp would have been required to post \$129 million and \$159 million, respectively, of additional collateral. PacifiCorp's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation or other factors.

(8) Short-term Debt and Other Financing Agreements

PacifiCorp has two unsecured credit facilities totaling \$1.395 billion, which includes a \$635 million unsecured credit facility that expires in October 2012 and a \$760 million unsecured credit facility that is fully available until July 2011. After July 2011, \$720 million is available until July 2012 and \$630 million is available until July 2013. The credit facilities include a fixed or variable borrowing option for which rates vary based on the borrowing option and PacifiCorp's credit ratings for its senior unsecured long-term debt securities. These facilities support PacifiCorp's commercial paper program and certain variable-rate tax-exempt bond obligations. As of December 31, 2010, PacifiCorp had \$36 million of commercial paper borrowings outstanding at a weighted-average interest rate of 0.3% and no borrowings outstanding under its credit facilities. As of December 31, 2009, PacifiCorp had no short-term debt outstanding.

As of December 31, 2010, PacifiCorp had \$601 million of letters of credit issued under committed arrangements, of which \$304 million were issued under the revolving credit agreements. As of December 31, 2009, PacifiCorp had \$517 million of letters of credit issued under committed arrangements, of which \$220 million were issued under the revolving credit agreements. These letters of credit support PacifiCorp's variable-rate tax-exempt bond obligations, are fully available as of December 31, 2010 and 2009, respectively, and expire periodically through May 2012. In addition, PacifiCorp's credit facilities supported \$38 million of unenhanced variable-rate tax-exempt bond obligations as of December 31, 2009.

Each revolving credit agreement and letter of credit arrangement requires that PacifiCorp's ratio of consolidated debt, including current maturities, to total capitalization at no time exceed 0.65 to 1.0. As of December 31, 2010, PacifiCorp was in compliance with the covenants of its revolving credit agreements and letter of credit arrangements.

The following table summarizes PacifiCorp's availability under its two unsecured revolving credit facilities as of December 31 (in millions):

2010:

Available revolving credit facilities	\$	1,395
Less:		
Short-term debt		(36)
Letters of credit and tax-exempt bond support		(304)
Net revolving credit facilities available	\$	<u>1,055</u>

2009:

Available revolving credit facilities	\$	1,395
Less:		
Support for unenhanced variable-rate tax-exempt bond obligations		(38)
Letters of credit and tax-exempt bond support		(220)
Net revolving credit facilities available	\$	<u>1,137</u>

As of December 31, 2010, PacifiCorp had approximately \$15 million of additional letters of credit issued on its behalf to provide credit support for certain transactions as required by third parties. These letters of credit were all fully available as of December 31, 2010 and have provisions that automatically extend the annual expiration dates for an additional year unless the issuing bank elects not to renew a letter of credit prior to the expiration date.

(9) Long-term Debt and Capital Lease Obligations

PacifiCorp's long-term debt and capital lease obligations were as follows as of December 31 (in millions):

	2010			2009	
	Par Value	Amount	Average Interest Rate	Amount	Average Interest Rate
First mortgage bonds:					
5.0% to 9.2%, due through 2015	\$ 1,040	\$ 1,040	6.5%	\$ 1,054	6.5%
5.5% to 8.6%, due 2016 to 2019	855	852	5.6	852	5.6
6.7% to 8.5%, due 2021 to 2023	324	324	7.7	324	7.7
6.7% due 2026	100	100	6.7	100	6.7
5.3% to 7.7%, due 2031 to 2035	800	798	6.3	798	6.3
5.8% to 6.4%, due 2036 to 2039	2,500	2,491	6.1	2,490	6.1
Tax-exempt bond obligations:					
Variable rates, due 2013 ⁽¹⁾	41	41	0.4	41	0.3
Variable rates, due 2014 to 2025	325	325	0.3	325	0.5
Variable rates, due 2016 to 2024 ^{(1) (2)}	221	221	0.3	176	0.2
Variable rates, due 2014 to 2025 ^{(1) (2)}	68	68	4.0	113	3.8
5.6% to 5.7%, due 2021 to 2023 ⁽¹⁾	71	71	5.6	71	5.6
6.2% due 2030	13	13	6.2	13	6.2
Total long-term debt	6,358	6,344		6,357	
Capital lease obligations:					
8.8% to 14.8%, due through 2036	57	57	11.4	59	11.7
Total long-term debt and capital lease obligations	\$ 6,415	\$ 6,401		\$ 6,416	

Reflected as:

	2010	2009
Current portion of long-term debt and capital lease obligations	\$ 588	\$ 16
Long-term debt and capital lease obligations	5,813	6,400
Total long-term debt and capital lease obligations	\$ 6,401	\$ 6,416

(1) Secured by pledged first mortgage bonds registered to and held by the tax-exempt bond trustee generally with the same interest rates, maturity dates and redemption provisions as the tax-exempt bond obligations.

(2) Interest rates fixed for a term at 3.4% to 4.1%, with \$68 million scheduled to reset in 2013. In 2010, \$45 million reset at a variable rate.

PacifiCorp's long-term debt may include provisions that allow PacifiCorp to redeem the long-term debt in whole or in part at any time. These provisions generally include make-whole premiums.

In September 2010, PacifiCorp completed a re-offering of variable-rate tax-exempt bond obligations totaling \$38 million. Letters of credit totaling \$39 million were issued under one of PacifiCorp's unsecured revolving credit facilities to provide credit enhancement and liquidity support for these previously unenhanced obligations.

In June 2010, PacifiCorp completed a re-offering of a \$45 million series of tax-exempt bond obligations. The interest rate for this obligation was previously fixed for a term which, upon scheduled expiration, was converted to a variable rate with credit enhancement and liquidity support provided by a \$46 million letter of credit issued under one of PacifiCorp's unsecured revolving credit facilities.

In January 2009, PacifiCorp issued \$350 million of its 5.50% First Mortgage Bonds due January 15, 2019 and \$650 million of its 6.00% First Mortgage Bonds due January 15, 2039. The net proceeds were used to repay short-term debt, to fund capital expenditures and for general corporate purposes.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately \$21 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2010.

PacifiCorp has regulatory authority from the OPUC and the Idaho Public Utilities Commission to issue an additional \$2.0 billion of long-term debt. PacifiCorp must make a notice filing with the Washington Utilities and Transportation Commission prior to any future issuance. Also, in December 2010, PacifiCorp filed a shelf registration statement with the United States Securities and Exchange Commission ("SEC") covering future first mortgage bond issuances.

As of December 31, 2010, PacifiCorp had variable-rate tax-exempt bond obligations totaling \$587 million that are supported by \$601 million of letters of credit issued under committed bank arrangements. These letters of credit were fully available as of December 31, 2010 and expire periodically through May 2012.

PacifiCorp's letters of credit agreements generally contain similar covenants and default provisions as those contained in PacifiCorp's revolving credit facilities, including a covenant not to exceed a specified debt-to-capitalization ratio of 0.65 to 1.0. PacifiCorp monitors these covenants on a regular basis in order to ensure that events of default do not occur. As of December 31, 2010, PacifiCorp was in compliance with these covenants.

PacifiCorp has entered into long-term agreements that qualify as capital leases and expire at various dates through October 2036 for transportation services, power purchase agreements, real estate and for the use of certain equipment. The transportation services agreements included as capital leases are for the right to use pipeline facilities to provide natural gas to three of PacifiCorp's generating facilities. Net capital lease assets of \$57 million and \$59 million as of December 31, 2010 and 2009, respectively, were included in property, plant and equipment, net in the Consolidated Balance Sheets.

As of December 31, 2010, the annual maturities of long-term debt and capital lease obligations, excluding unamortized discounts and including interest on capital lease obligations, for 2011 and thereafter are as follows (in millions):

	Long-term Debt	Capital Lease Obligations	Total
2011	\$ 587	\$ 8	\$ 595
2012	17	7	24
2013	261	12	273
2014	253	8	261
2015	122	7	129
Thereafter	5,118	87	5,205
Total	6,358	129	6,487
Unamortized discount	(14)	—	(14)
Amounts representing interest	—	(72)	(72)
Total	\$ 6,344	\$ 57	\$ 6,401

(10) Asset Retirement Obligations

PacifiCorp estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including plan revisions, inflation and changes in the amount and timing of the expected work.

PacifiCorp does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain transmission, distribution and other assets cannot currently be estimated and no amounts are recognized on the Consolidated Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates and in accordance with accepted regulatory practices. These accruals totaled \$782 million and \$755 million as of December 31, 2010 and 2009, respectively.

As discussed in Note 2, PacifiCorp adopted authoritative guidance as of January 1, 2010 that required equity method accounting treatment of its coal mining joint venture Bridger Coal. As a result, PacifiCorp deconsolidated \$79 million of ARO liabilities and mine reclamation trust funds. The following table reconciles the beginning and ending balances of PacifiCorp's ARO liability for the years ended December 31 (in millions):

	2010	2009
Beginning balance	\$ 181	\$ 165
Deconsolidation of Bridger Coal	(79)	—
Change in estimated costs ⁽¹⁾	2	24
Additions	2	3
Retirements	(6)	(20)
Accretion	5	9
Ending balance	<u>\$ 105</u>	<u>\$ 181</u>
Reflected as:		
Other current liabilities	\$ 4	\$ 15
Other long-term liabilities	101	166
	<u>\$ 105</u>	<u>\$ 181</u>
Investment trusts⁽²⁾	<u>\$ 2</u>	<u>\$ 81</u>

(1) Results from changes in the timing and amounts of estimated cash flows for certain plant and mine reclamation.

(2) Amount as of December 31, 2009 substantially represents a trust for final reclamation of the Jim Bridger mine, including the noncontrolling interest joint-owner portion. Amount is included in other current assets and investments and other assets on the Consolidated Balance Sheets.

Certain of PacifiCorp's decommissioning and reclamation obligations relate to jointly owned facilities and mine sites. PacifiCorp is committed to pay a proportionate share of the decommissioning or reclamation costs. In the event of a default by any of the other joint participants, PacifiCorp may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. PacifiCorp's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities.

(11) Employee Benefit Plans

PacifiCorp sponsors defined benefit pension plans that cover the majority of its employees and also provides certain postretirement healthcare and life insurance benefits through various plans for eligible retirees. In addition, PacifiCorp sponsors a defined contribution 401(k) employee savings plan ("401(k) Plan"). Non-union employees hired on or after January 1, 2008 and certain union employees are not eligible to participate in the PacifiCorp Retirement Plan ("Retirement Plan"). These employees are eligible to receive enhanced benefits under the 401(k) Plan.

Pension and Other Postretirement Benefit Plans

PacifiCorp's pension plans include a non-contributory defined benefit pension plan, the Retirement Plan; the Supplemental Executive Retirement Plan ("SERP"); and certain joint trust union plans to which PacifiCorp contributes on behalf of certain bargaining units. All non-union Retirement Plan participants that did not elect to receive equivalent fixed contributions to the 401(k) Plan effective January 1, 2009, earn benefits based on a cash balance formula. For most union employees, benefits under the Retirement Plan were frozen at various dates from December 31, 2007 through March 31, 2010 as they are now being provided with enhanced 401(k) Plan benefits. Certain union Retirement Plan participants continue to earn benefits under the Retirement Plan based on the employee's years of service and a final average pay formula.

The cost of other postretirement benefits, including healthcare and life insurance benefits for eligible retirees, is accrued over the active service period of employees. PacifiCorp funds these other postretirement benefits through a combination of funding vehicles. PacifiCorp also contributes to joint trust union plans for postretirement benefits offered to certain bargaining units.

Healthcare Reform Legislation

In March 2010, the President signed into law healthcare reform legislation that included provisions to eliminate the tax deductibility of other postretirement costs to the extent of retiree drug subsidies received from the federal government beginning after December 31, 2012. Accordingly, PacifiCorp increased deferred income tax liabilities and regulatory assets by \$39 million. PacifiCorp has received authorization from various state regulatory commissions for deferral of the \$16 million of the adjustment that related to income tax benefits associated with amounts previously recognized as net periodic benefit costs. The remaining \$23 million of the adjustment relates to income tax benefits that will no longer be realized in the future when the net periodic benefit cost is recognized and for which recovery of the resulting higher future income tax expense will be addressed through on-going ratemaking proceedings.

The new law also contains a provision that requires a 40% excise tax for group health benefits that are provided to employees above certain premium thresholds beginning in 2018. The tax would apply to the amount of premiums in excess of the thresholds. Virtually all major areas of the healthcare reform legislation, including the 40% excise tax, are subject to interpretation and implementation rules that may take several years to complete. As of December 31, 2010, PacifiCorp's other postretirement benefit obligation increased by \$12 million as a result of the projected impact of the excise tax on benefits provided to a certain bargaining unit.

Curtailments

In August 2008, non-union employee participants in the Retirement Plan were offered the option to continue to receive pay credits in their current cash balance pension plan or receive equivalent fixed contributions to the 401(k) Plan. The election was effective January 1, 2009 and resulted in the recognition of a \$38 million curtailment gain. PacifiCorp recorded \$36 million of the curtailment gain representing the amount to be returned to customers in rates as a regulatory deferral, resulting in a reduction to regulatory assets as of December 31, 2008. The regulatory deferral is being amortized over a period of three to 10 years based on agreements with various state regulatory commissions.

Effective December 31, 2007, Local Union No. 659 of the International Brotherhood of Electrical Workers ("Local 659") elected to cease participation in the Retirement Plan and participate only in the 401(k) Plan with enhanced benefits. As a result of this election, the Local 659 participants' Retirement Plan benefits were frozen as of December 31, 2007. This change resulted in a \$2 million curtailment gain that was recorded as a regulatory deferral based on the requirement to return the amount to customers in rates and is being amortized over a period of three to 10 years based on agreements with various state regulatory commissions. Also as a result of this change, PacifiCorp's pension benefit obligation and regulatory assets each decreased by \$13 million.

Effective March 31, 2010, the Utility Workers Union of America Local Union No. 127 ("Local 127") elected to cease participation in the Retirement Plan and participate only in the 401(k) Plan with enhanced benefits. As a result of this election, the Local 127 participants' Retirement Plan benefits were frozen on March 31, 2010. This change resulted in a \$2 million curtailment gain that was recorded as a regulatory deferral and is being amortized over periods similar to those required for other recent curtailments. Also as a result of this change, PacifiCorp's pension benefit obligation and regulatory assets each decreased by \$14 million.

Net Periodic Benefit Cost

For purposes of calculating the expected return on plan assets, a market-related value is used. The market-related value of plan assets is calculated by spreading the difference between expected and actual investment returns over a five-year period beginning after the first year in which they occur.

Net periodic benefit cost for the plans included the following components for the years ended December 31 (in millions):

	Pension			Other Postretirement		
	2010	2009	2008	2010	2009	2008
Service cost ⁽¹⁾	\$ 12	\$ 16	\$ 27	\$ 6	\$ 5	\$ 7
Interest cost	66	71	67	31	33	33
Expected return on plan assets	(74)	(70)	(72)	(30)	(29)	(28)
Net amortization	23	10	7	14	12	15
Net amortization of regulatory deferrals	(10)	(8)	—	1	1	—
Curtailment gain	—	—	(2)	—	—	—
Net periodic benefit cost	<u>\$ 17</u>	<u>\$ 19</u>	<u>\$ 27</u>	<u>\$ 22</u>	<u>\$ 22</u>	<u>\$ 27</u>

(1) Service cost excludes \$13 million of contributions to the joint trust union plans during each of the years ended December 31, 2010, 2009 and 2008.

Funded Status

The following table is a reconciliation of the fair value of plan assets for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2010	2009	2010	2009
Plan assets at fair value, beginning of year	\$ 825	\$ 692	\$ 350	\$ 284
Employer contributions	117	54	24	24
Participant contributions	—	—	9	9
Actual return on plan assets	102	160	44	70
Benefits paid	(84)	(81)	(38)	(37)
Plan assets at fair value, end of year	<u>\$ 960</u>	<u>\$ 825</u>	<u>\$ 389</u>	<u>\$ 350</u>

The following table is a reconciliation of the benefit obligations for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2010	2009	2010	2009
Benefit obligation, beginning of year	\$ 1,199	\$ 1,070	\$ 545	\$ 489
Service cost	12	16	6	5
Interest cost	66	71	31	33
Participant contributions	—	—	9	9
Plan amendments	—	(1)	—	(4)
Curtailment	(14)	—	—	—
Actuarial loss	57	124	25	47
Benefits paid, net of Medicare subsidy	(84)	(81)	(35)	(34)
Benefit obligation, end of year	<u>\$ 1,236</u>	<u>\$ 1,199</u>	<u>\$ 581</u>	<u>\$ 545</u>
Accumulated benefit obligation, end of year	<u>\$ 1,230</u>	<u>\$ 1,178</u>		

The funded status of the plans and the amounts recognized on the Consolidated Balance Sheets as of December 31 are as follows (in millions):

	Pension		Other Postretirement	
	2010	2009	2010	2009
Plan assets at fair value, end of year	\$ 960	\$ 825	\$ 389	\$ 350
Less - Benefit obligation, end of year	1,236	1,199	581	545
Funded status	<u>\$ (276)</u>	<u>\$ (374)</u>	<u>\$ (192)</u>	<u>\$ (195)</u>
Amounts recognized on the Consolidated Balance Sheets:				
Other current liabilities	\$ (4)	\$ (4)	\$ —	\$ —
Other long-term liabilities	(272)	(370)	(192)	(195)
Amounts recognized	<u>\$ (276)</u>	<u>\$ (374)</u>	<u>\$ (192)</u>	<u>\$ (195)</u>

The SERP has no plan assets; however, PacifiCorp has a Rabbi trust that holds corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERP. The cash surrender value of all of the policies included in the Rabbi trust, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was \$40 million and \$39 million as of December 31, 2010 and 2009, respectively. These assets are not included in the plan assets in the above table, but are reflected on the Consolidated Balance Sheets. The portion of the pension plans' projected benefit obligation related to the SERP was \$56 million and \$55 million as of December 31, 2010 and 2009, respectively.

Unrecognized Amounts

The portion of the funded status of the plans not yet recognized in net periodic benefit cost as of December 31 is as follows (in millions):

	Pension		Other Postretirement	
	2010	2009	2010	2009
Net loss	\$ 507	\$ 523	\$ 142	\$ 135
Prior service credit	(50)	(60)	—	—
Net transition obligation	—	—	19	29
Regulatory deferrals	(16)	(24)	4	5
Total	<u>\$ 441</u>	<u>\$ 439</u>	<u>\$ 165</u>	<u>\$ 169</u>

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2010 and 2009 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss, Net	Total
Pension			
Balance, January 1, 2009	\$ 404	\$ 4	\$ 408
Net loss arising during the year	29	5	34
Prior service credit arising during the year	(1)	—	(1)
Net amortization	(2)	—	(2)
Total	26	5	31
Balance, December 31, 2009	430	9	439
Net loss arising during the year	27	2	29
Curtailment	(14)	—	(14)
Net amortization	(13)	—	(13)
Total	—	2	2
Balance, December 31, 2010	\$ 430	\$ 11	\$ 441

	Regulatory Asset	Deferred Income Taxes	Total
Other Postretirement			
Balance, January 1, 2009	\$ 160	\$ 20	\$ 180
Net loss arising during the year	4	3	7
Prior service credit arising during the year	(1)	—	(1)
Transition obligation credit arising during the year	(3)	—	(3)
Net amortization	(14)	—	(14)
Total	(14)	3	(11)
Balance, December 31, 2009	146	23	169
Net loss arising during the year	11	—	11
Income tax benefits no longer realizable ⁽¹⁾	23	(23)	—
Net amortization	(15)	—	(15)
Total	19	(23)	(4)
Balance, December 31, 2010	\$ 165	\$ —	\$ 165

(1) Represents adjustments to regulatory assets associated with income tax benefits that will no longer be realized when the net periodic benefit cost is recognized as a result of the healthcare reform legislation.

The net loss, prior service credit, net transition obligation and regulatory deferrals that will be amortized in 2011 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Credit	Net Transition Obligation	Regulatory Deferrals	Total
Pension	\$ 37	\$ (8)	\$ —	\$ (9)	\$ 20
Other postretirement	6	—	11	1	18
Total	\$ 43	\$ (8)	\$ 11	\$ (8)	\$ 38

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost for the years ended December 31 were as follows:

	Pension			Other Postretirement		
	2010	2009	2008	2010	2009	2008
Benefit obligations as of December 31:						
Discount rate	5.35%	5.80%	6.90%	5.45%	5.85%	6.90%
Rate of compensation increase	3.50	3.00	3.50	N/A	N/A	N/A
Net benefit cost for the years ended:						
Discount rate	5.80%	6.90%	6.30%	5.85%	6.90%	6.45%
Expected return on plan assets	7.75	7.75	7.75	7.75	7.75	7.75
Rate of compensation increase	3.00	3.50	4.00	N/A	N/A	N/A

In establishing its assumption as to the expected return on plan assets, PacifiCorp utilizes the expected asset allocation and return assumptions for each asset class based on historical performance and forward-looking views of the financial markets.

	2010	2009
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	8%	8%
Rate that the cost trend rate gradually declines to	5%	5%
Year that the rate reaches the rate it is assumed to remain at	2016	2016

A one percentage-point change in assumed healthcare cost trend rates would have the following effects (in millions):

	Increase (Decrease)	
	One Percentage-Point Increase	One Percentage-Point Decrease
Effect on total service and interest cost	\$ 2	\$ (2)
Effect on other postretirement benefit obligation	41	(33)

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be \$71 million and \$28 million, respectively, during 2011. Funding to PacifiCorp's Retirement Plan trust is based upon the actuarially determined costs of the plan and the requirements of the Internal Revenue Code, the Employee Retirement Income Security Act of 1974 and the Pension Protection Act of 2006, as amended. PacifiCorp considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the Pension Protection Act of 2006, as amended. PacifiCorp's funding policy for its other postretirement benefit plans is to contribute an amount equal to the sum of the net periodic benefit cost and the amount of Medicare subsidies expected to be earned during the period.

The expected benefit payments to participants in PacifiCorp's pension and other postretirement benefit plans for 2011 through 2015 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments			
	Pension	Other Postretirement		
		Gross	Medicare Subsidy	Net of Subsidy
2011	\$ 97	\$ 34	\$ (3)	\$ 31
2012	99	36	(3)	33
2013	105	39	(3)	36
2014	112	42	(4)	38
2015	107	43	(4)	39
2016 - 2020	513	242	(30)	212

Plan Assets

Investment Policy and Asset Allocations

PacifiCorp's investment policy for its pension and other postretirement benefit plans is to balance risk and return through a diversified portfolio of fixed income securities, equity securities and other alternative investments. Maturities for fixed income securities are managed to targets consistent with prudent risk tolerances. The plans retain outside investment advisors to manage plan investments within the parameters outlined by the PacifiCorp Pension Committee. The investment portfolio is managed in line with the investment policy with sufficient liquidity to meet near-term benefit payments. The return on assets assumption for each plan is based on a weighted-average of the expected historical performance for the types of assets in which the plans invest.

The target allocations (percentage of plan assets) for PacifiCorp's pension and other postretirement benefit plan assets are as follows as of December 31, 2010:

	Pension ⁽¹⁾	Other Postretirement ⁽¹⁾
	%	%
Fixed-income securities ⁽²⁾	33 - 37	33 - 37
Equity securities ⁽²⁾	53 - 57	61 - 65
Limited partnership interests	8 - 12	1 - 3
Cash and cash equivalents	0 - 1	0 - 1

(1) PacifiCorp's Retirement Plan trust includes a separate account that is used to fund benefits for the other postretirement benefit plan. In addition to this separate account, the assets for the other postretirement benefit plans are held in two Voluntary Employees' Beneficiaries Association ("VEBA") trusts, each of which has its own investment allocation strategies. Target allocations for the other postretirement benefit plans include the separate account of the Retirement Plan trust and the two VEBA trusts.

(2) For purposes of target allocation percentages and consistent with the plans' investment policy, investment funds have been allocated based on the underlying investments in fixed-income and equity securities.

Fair Value Measurements

The following table presents the fair value of plan assets, by major category, for PacifiCorp's defined benefit pension plans (in millions):

	Input Levels for Fair Value Measurements			
	Level 1 ⁽¹⁾	Level 2 ⁽¹⁾	Level 3 ⁽¹⁾	Total
As of December 31, 2010				
Cash and cash equivalents	\$ —	\$ 8	\$ —	\$ 8
Fixed-income securities:				
United States government obligations	20	—	—	20
Corporate obligations	—	52	—	52
International government obligations	—	81	—	81
Municipal obligations	—	4	—	4
Agency, asset and mortgage-backed obligations	—	49	—	49
Equity securities:				
United States equity securities	366	—	—	366
International equity securities	7	—	—	7
Investment funds ⁽²⁾	109	180	—	289
Limited partnership interests ⁽³⁾	—	—	84	84
Total	\$ 502	\$ 374	\$ 84	\$ 960
As of December 31, 2009				
Cash and cash equivalents	\$ —	\$ 8	\$ —	\$ 8
Fixed-income securities:				
United States government obligations	20	—	—	20
Corporate obligations	—	44	—	44
International government obligations	—	65	—	65
Municipal obligations	—	2	—	2
Agency, asset and mortgage-backed obligations	—	43	—	43
Equity securities:				
United States equity securities	296	—	—	296
International equity securities	4	—	—	4
Investment funds ⁽²⁾	95	168	—	263
Limited partnership interests ⁽³⁾	—	—	80	80
Total	\$ 415	\$ 330	\$ 80	\$ 825

(1) Refer to Note 6 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These investment funds represent equity and fixed-income securities as of December 31, 2010 and 2009, of approximately 60% and 40% and 61% and 39%, respectively.

(3) Limited partnership interests include several private equity funds that invest primarily in buyout, growth equity and venture capital.

The following table presents the fair value of plan assets, by major category, for PacifiCorp's defined benefit other postretirement plan (in millions):

	Input Levels for Fair Value Measurements			Total
	Level 1 ⁽¹⁾	Level 2 ⁽¹⁾	Level 3 ⁽¹⁾	
December 31, 2010				
Cash and cash equivalents	\$ 2	\$ 1	\$ —	\$ 3
Fixed-income securities:				
United States government obligations	2	—	—	2
Corporate obligations	—	4	—	4
International government obligations	—	7	—	7
Agency, asset and mortgage-backed obligations	—	4	—	4
Equity securities:				
United States equity securities	134	—	—	134
International equity securities	3	—	—	3
Investment funds ⁽²⁾	118	107	—	225
Limited partnership interests ⁽³⁾	—	—	7	7
Total	\$ 259	\$ 123	\$ 7	\$ 389
December 31, 2009				
Cash and cash equivalents	\$ 4	\$ —	\$ —	\$ 4
Fixed-income securities:				
United States government obligations	2	—	—	2
Corporate obligations	—	4	—	4
International government obligations	—	6	—	6
Agency, asset and mortgage-backed obligations	—	4	—	4
Equity securities:				
United States equity securities	115	—	—	115
International equity securities	2	—	—	2
Investment funds ⁽²⁾	101	104	—	205
Limited partnership interests ⁽³⁾	—	—	8	8
Total	\$ 224	\$ 118	\$ 8	\$ 350

(1) Refer to Note 6 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These investment funds represent equity and fixed-income securities as of December 31, 2010 and 2009, of approximately 47% and 53% and 50% and 50%, respectively.

(3) Limited partnership interests include several private equity funds that invest primarily in buyout, growth equity and venture capital.

When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics. When observable market data is not available, the fair value is determined using unobservable inputs, such as estimated future cash flows, purchase multiples paid in other comparable third-party transactions or other information. Investments in limited partnerships are valued at estimated fair value based on the Plan's proportionate share of the partnerships' fair value as recorded in the partnerships' most recently available financial statements adjusted for recent activity and forecasted returns. The fair values recorded in the partnerships' financial statements are generally determined based on closing public market prices for publicly traded securities and as determined by the general partners for other investments based on factors including estimated future cash flows, purchase multiples paid in other comparable third-party transactions, comparable public company trading multiples and other information.

The following table reconciles the beginning and ending balances of PacifiCorp's plan assets measured at fair value using significant Level 3 inputs for the years ended December 31 (in millions):

	Limited Partnership Interests	
	Pension	Other Postretirement
Balance, January 1, 2009	\$ 78	\$ 7
Actual return on plan assets still held at December 31, 2009	5	1
Purchases, sales, distributions and settlements	(3)	—
Balance, December 31, 2009	\$ 80	\$ 8
Actual return on plan assets still held at December 31, 2010	10	—
Purchases, sales, distributions and settlements	(6)	(1)
Balance, December 31, 2010	<u>\$ 84</u>	<u>\$ 7</u>

Defined Contribution Plan

PacifiCorp sponsors a defined contribution plan covering substantially all employees. PacifiCorp's contributions are based primarily on each participant's level of contribution and cannot exceed the maximum allowable for tax purposes. PacifiCorp's contributions to the 401(k) Plan were \$39 million, \$34 million and \$23 million for the years ended December 31, 2010, 2009 and 2008, respectively. As previously described, certain participants now receive enhanced benefits in the 401(k) Plan and no longer accrue benefits in the Retirement Plan.

(12) Income Taxes

Income tax expense consists of the following for the years ended December 31 (in millions):

	2010	2009	2008
Current:			
Federal	\$ (498)	\$ (417)	\$ (64)
State	(1)	6	(6)
Total	<u>(499)</u>	<u>(411)</u>	<u>(70)</u>
Deferred:			
Federal	684	619	276
State	30	30	36
Total	<u>714</u>	<u>649</u>	<u>312</u>
Investment tax credits	(4)	(4)	(4)
Total income tax expense	<u>\$ 211</u>	<u>\$ 234</u>	<u>\$ 238</u>

A reconciliation of the federal statutory income tax rate to the effective income tax rate applicable to income before income tax expense is as follows for the years ended December 31:

	2010	2009	2008
Federal statutory tax rate	35%	35%	35%
State taxes, net of federal benefit	3	3	3
Tax credits ⁽¹⁾	(8)	(6)	(5)
Effects of ratemaking	(2)	—	1
Other	(1)	(2)	—
Effective income tax rate	27%	30%	34%

- (1) Primarily attributable to the impact of federal renewable electricity production tax credits related to qualifying wind-powered generating facilities that extend 10 years from the date the facilities were placed in service.

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2010	2009
Deferred tax assets:		
Regulatory liabilities	\$ 322	\$ 326
Employee benefits	190	247
Derivative contracts	184	140
Other	196	169
	<u>892</u>	<u>882</u>
Deferred tax liabilities:		
Property, plant and equipment	(3,302)	(2,599)
Regulatory assets ⁽¹⁾	(928)	(838)
Other	(27)	(31)
	<u>(4,257)</u>	<u>(3,468)</u>
Net deferred tax liability	<u>\$ (3,365)</u>	<u>\$ (2,586)</u>
Reflected as:		
Deferred income taxes - current assets	\$ 83	\$ 39
Deferred income taxes - non-current liabilities	(3,448)	(2,625)
	<u>\$ (3,365)</u>	<u>\$ (2,586)</u>

- (1) Includes \$278 million and \$262 million of deferred income tax liabilities associated with property, plant and equipment as of December 31, 2010 and 2009, respectively, for which the income tax benefits were previously flowed through to customers and that will be included in rates when the temporary difference reverse.

The sale of PacifiCorp to MEHC on March 21, 2006 triggered certain tax related events that remain unsettled. PacifiCorp does not believe that the tax, if any, arising from the ultimate settlement of these events will have a material impact on its consolidated financial results.

The United States Internal Revenue Service has closed its examination of PacifiCorp's income tax returns through the 2003 tax year. In most cases, state jurisdictions have closed their examinations of PacifiCorp's income tax returns through 1993.

As of December 31, 2010 and 2009, net unrecognized tax benefits totaled \$70 million and \$75 million, respectively, which included \$9 million and \$6 million, respectively, of tax positions that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect PacifiCorp's effective tax rate.

(13) Commitments and Contingencies

Legal Matters

PacifiCorp is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. PacifiCorp does not believe that such normal and routine litigation will have a material impact on its consolidated financial results. PacifiCorp is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines, penalties and other costs in substantial amounts and are described below.

Environmental Laws and Regulations

PacifiCorp is subject to federal, state and local laws and regulations regarding air and water quality, renewable portfolio standards, emissions performance standards, climate change, coal combustion byproducts, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact PacifiCorp's current and future operations. PacifiCorp believes it is in material compliance with all applicable laws and regulations.

New Source Review

As part of an industry-wide investigation to assess compliance with the New Source Review ("NSR") and Prevention of Significant Deterioration ("PSD") provisions, the Environmental Protection Agency ("EPA") has requested from numerous utilities information and supporting documentation regarding their capital projects for various generating facilities. Between 2001 and 2003, PacifiCorp responded to requests for information relating to its capital projects at its generating facilities, and has been engaged in periodic discussions with the EPA over several years regarding its historical projects and their compliance with NSR and PSD provisions. A NSR enforcement case against another utility has been decided by the United States Supreme Court, holding that an increase in annual emissions of a generating facility, when combined with a modification (i.e., a physical or operational change), may trigger NSR permitting. PacifiCorp could be required to install additional emissions controls, and incur additional costs and penalties, in the event it is determined that PacifiCorp's historical projects did not meet all regulatory requirements. The impact of these additional emissions controls, costs and penalties, if any, on PacifiCorp's consolidated financial results cannot be determined at this time.

Hydroelectric Relicensing

PacifiCorp's hydroelectric portfolio consists of 46 generating facilities with an aggregate facility net owned capacity of 1,157 megawatts ("MW"). The Federal Energy Regulatory Commission ("FERC") regulates 98% of the net capacity of this portfolio through 16 individual licenses, which typically have terms of 30 to 50 years. PacifiCorp expects to incur ongoing operating and maintenance expense and capital expenditures associated with the terms of its renewed hydroelectric licenses and settlement agreements, including natural resource enhancements. PacifiCorp's Klamath hydroelectric system is currently operating under annual licenses. Substantially all of PacifiCorp's remaining hydroelectric generating facilities are operating under licenses that expire between 2030 and 2058.

Klamath Hydroelectric System - Klamath River, Oregon and California

PacifiCorp is currently operating under an annual license for the Klamath hydroelectric system as part of a relicensing process that includes possible removal of the system's four mainstem dams.

In February 2010, PacifiCorp, the United States Department of the Interior, the United States Department of Commerce, the State of California, the State of Oregon and various other governmental and non-governmental settlement parties signed the Klamath Hydroelectric Settlement Agreement ("KHSA"). Among other things, the KHSA provides that the United States Department of the Interior conduct scientific and engineering studies to assess by March 31, 2012 whether removal of the Klamath hydroelectric system's four mainstem dams is in the public interest and will advance the Klamath Basin's salmonid fisheries. If it is determined that dam removal should proceed, dam removal is expected to commence no earlier than 2020.

Under the KHSA, PacifiCorp and its customers are protected from uncapped dam removal costs and liabilities. For dam removal to occur, federal legislation consistent with the KHSA must be enacted to provide, among other things, protection for PacifiCorp from all liabilities associated with dam removal activities. If Congress does not enact legislation, then PacifiCorp will resume relicensing at the FERC. In addition, the KHSA limits PacifiCorp's contribution to dam removal costs to no more than \$200 million, of which up to \$184 million would be collected from PacifiCorp's Oregon customers with the remainder to be collected from PacifiCorp's California customers. An additional \$250 million for dam removal costs is expected to be raised through a California bond measure or other appropriate State of California financing mechanism. If dam removal costs exceed \$200 million and if the State of California is unable to raise the additional funds necessary for dam removal costs, sufficient funds would need to be provided by an entity other than PacifiCorp in order for the KHSA and dam removal to proceed.

PacifiCorp has begun collection of surcharges from Oregon customers for their share of dam removal costs, as approved by the OPUC, and is depositing the proceeds in a trust account maintained by the OPUC. The California Public Utilities Commission issued a proposed decision in February 2011 with similar provisions for California customers and a final order is pending.

As of December 31, 2010, the net book value of PacifiCorp's Klamath hydroelectric system generating facilities was \$59 million with an average remaining depreciable life of 36 years. As of December 31, 2010, relicensing and settlement costs associated with the Klamath hydroelectric system totaled \$74 million. PacifiCorp received approval from the OPUC to depreciate its hydroelectric system generating facilities and relicensing and settlement costs through the expected dam removal date, and is at various stages of seeking approval in its remaining jurisdictions.

Hydroelectric Commitments

As described above, certain of PacifiCorp's hydroelectric licenses contain requirements for PacifiCorp to make certain capital and operating expenditures related to its hydroelectric facilities. PacifiCorp estimates it is obligated to make capital expenditures of approximately \$321 million over the next 10 years related to these licenses.

FERC Issues

FERC Investigation

During 2007, the Western Electricity Coordinating Council ("WECC") audited PacifiCorp's compliance with several of the reliability standards developed by the North American Electric Reliability Corporation ("NERC"). In April 2008, PacifiCorp received notice of a preliminary non-public investigation from the FERC and the NERC to determine whether an outage that occurred in PacifiCorp's transmission system in February 2008 involved any violations of reliability standards. In November 2008, PacifiCorp received preliminary findings from the FERC staff regarding its non-public investigation into the February 2008 outage. Also in November 2008, in conjunction with the reliability standards review, the FERC assumed control of certain aspects of the WECC's 2007 audit. PacifiCorp has engaged in discussions with FERC staff regarding findings related to the non-public investigation, which includes the WECC's findings that are now being processed by the FERC. PacifiCorp does not believe that the outcome of the non-public investigation will have a material impact on its consolidated financial results.

Northwest Refund Case

In June 2003, the FERC terminated its proceeding relating to the possibility of requiring refunds for wholesale spot-market bilateral sales in the Pacific Northwest between December 2000 and June 2001. The FERC concluded that ordering refunds would not be an appropriate resolution of the matter. In November 2003, the FERC issued its final order denying rehearing. Several market participants, excluding PacifiCorp, filed petitions in the United States Court of Appeals for the Ninth Circuit ("Ninth Circuit") for review of the FERC's final order. In August 2007, the Ninth Circuit concluded 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 in the Pacific Northwest spot market made by the California Energy Resources Scheduling ("CERS") division of the California Department of Water Resources. Without issuing the mandate order, the Ninth Circuit remanded the case to the FERC to (a) 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; (b) include sales to CERS in its analysis; and (c) further consider its refund decision in light of related, intervening opinions of the court. The Ninth Circuit offered no opinion on the FERC's findings based on the record established by the administrative law judge and did not rule on the merits of the FERC's November 2003 decision to deny refunds. In April 2009, the Ninth Circuit issued a formal mandate order, completing the remand of the case to the FERC, which has not yet undertaken further action. PacifiCorp cannot predict the future course of this proceeding and its impact on its consolidated financial results, if any, at this time.

Purchase Obligations

PacifiCorp has the following purchase obligations that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2010 are as follows (in millions):

	2011	2012	2013	2014	2015	Thereafter	Total
Purchased electricity	\$ 170	\$ 136	\$ 135	\$ 100	\$ 96	\$ 543	\$ 1,180
Fuel	764	604	595	573	472	2,591	5,599
Construction	393	97	20	9	9	37	565
Transmission	115	108	97	83	62	745	1,210
Operating leases	6	5	4	4	3	39	61
Maintenance, service and other commitments	44	19	16	12	6	53	150
Total commitments	<u>\$ 1,492</u>	<u>\$ 969</u>	<u>\$ 867</u>	<u>\$ 781</u>	<u>\$ 648</u>	<u>\$ 4,008</u>	<u>\$ 8,765</u>

Purchased Electricity

As part of its energy resource portfolio, PacifiCorp acquires a portion of its electricity through long-term purchases and exchange agreements. PacifiCorp has several power purchase agreements with wind-powered and other generating facilities that are not included in the table above as the payments are based on the amount of energy generated and there are no minimum payments. Included in the purchased electricity payments are any power agreements that meet the definition of an operating lease.

Included in the minimum fixed annual payments for purchased electricity above are commitments to purchase electricity from several hydroelectric systems under long-term arrangements with public utility districts. These purchases are made on a "cost-of-service" basis for a stated percentage of system output and for a like percentage of system operating expenses and debt service. These costs are included in energy costs on the Consolidated Statements of Operations. PacifiCorp is required to pay its portion of operating costs and its portion of the debt service, whether or not any electricity is produced. These arrangements accounted for less than 5% of PacifiCorp's 2010, 2009 and 2008 energy sources.

Fuel

PacifiCorp has "take or pay" coal and natural gas contracts that require minimum payments.

Construction

PacifiCorp has purchase obligations for its ongoing construction programs to meet increased electricity usage, customer growth, system reliability objectives, develop incremental generating capacity, foster the use of renewable resources, enhance transmission capabilities and mitigate environmental impacts through the installation of emission reduction technology. The amounts included in the table above relate to firm commitments. The following discussion describes PacifiCorp's overall commitments and includes amounts that PacifiCorp is not yet firmly committed through a purchase order or other agreement.

PacifiCorp has significant future capital requirements. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of such reviews. Estimates may change significantly at any time as a result of, among other factors, changes in rules and regulations, including environmental; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment, and materials; and the cost and availability of capital.

As part of the March 2006 acquisition of PacifiCorp, MEHC and PacifiCorp made a number of commitments to the state regulatory commissions in all six states in which PacifiCorp has retail customers. These commitments are generally being implemented over several years following the acquisition and are subject to subsequent regulatory review and approval. As of December 31, 2010, the status of the key financial commitments was as follows:

- Invest approximately \$812 million in emissions reduction technology for PacifiCorp's existing coal-fired generating facilities. Through December 31, 2010, PacifiCorp had spent a total of \$1.2 billion, including non-cash equity AFUDC, on these emissions reduction projects. In June 2010, PacifiCorp filed notification of its completion of this commitment with the applicable state regulatory commissions.
- Invest in certain transmission and distribution system projects that would enhance reliability, facilitate the receipt of renewable resources and enable further system optimization in an amount that was originally estimated to be approximately \$520 million at the date of the acquisition. Through December 31, 2010, PacifiCorp had spent a total of \$958 million in capital expenditures, including non-cash equity AFUDC, which was in excess of the original estimate due to the evolving nature of the projects agreed to in the commitment. This amount includes costs for the transmission expansion program discussed below.

PacifiCorp's Energy Gateway Transmission Expansion Program, which began in 2007, represents a plan to build approximately 2,000 miles of new high-voltage transmission lines, with an estimated cost exceeding \$6 billion, primarily in Wyoming, Utah, Idaho and Oregon. The plan includes several transmission line segments that will: (a) address customer load growth; (b) improve system reliability; (c) reduce transmission system constraints; (d) provide access to diverse generation resources, including renewable resources; and (e) improve the flow of electricity throughout PacifiCorp's six-state service area.

Transmission

PacifiCorp has agreements for the right to transmit electricity over other entities' transmission lines to facilitate delivery to PacifiCorp's customers.

Operating Leases and Easements

PacifiCorp has non-cancelable operating leases primarily for office equipment, office space, certain operating facilities, land and equipment under operating leases that expire at various dates through the year ending December 31, 2092. These leases generally require PacifiCorp to pay for insurance, taxes and maintenance applicable to the leased property. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. PacifiCorp also has non-cancelable easements for land on which its wind-powered generating facilities are located. Rent expense on non-cancelable operating leases totaled \$15 million for 2010, \$13 million for 2009 and \$16 million for 2008.

Maintenance, Service and Other Commitments

PacifiCorp has various non-cancelable maintenance, service and other commitments primarily related to turbine and equipment maintenance and various other service agreements.

(14) Preferred Stock

PacifiCorp's preferred stock was as follows as of December 31 (shares in thousands, dollars in millions, except per share amounts):

	Redemption Price Per Share	2010		2009	
		Shares	Amount	Shares	Amount
Series:					
Serial Preferred, \$100 stated value, 3,500 shares authorized					
4.52% to 4.72%	\$102.3 to \$103.5	149	\$ 15	157	\$ 15
5.00% to 5.40%	\$100.0 to \$101.0	108	10	108	10
6.00%	Non-redeemable	6	1	6	1
7.00%	Non-redeemable	18	2	18	2
5% Preferred, \$100 stated value, 127 shares authorized					
	\$110.0	126	13	126	13
		407	\$ 41	415	\$ 41

Generally, preferred stock is redeemable at stipulated prices plus accrued dividends, subject to certain restrictions. In the event of voluntary liquidation, all preferred stock is entitled to stated value or a specified preference amount per share plus accrued dividends. Upon involuntary liquidation, all preferred stock is entitled to stated value plus accrued dividends. Dividends on all preferred stock are cumulative. Holders also have the right to elect members to the PacifiCorp Board of Directors in the event dividends payable are in default in an amount equal to four full quarterly payments.

In May 2010, PacifiCorp received an unsolicited offer to repurchase certain shares of PacifiCorp's preferred stock. As a result, PacifiCorp purchased and canceled 4,036 shares of its \$100 stated value 4.72% Serial Preferred Stock for \$318,844, at an average price per share of \$79, and 3,266 shares of its \$100 stated value 4.56% Serial Preferred Stock for \$241,684, at an average price per share of \$74.

Dividends declared but not yet due for payment on preferred stock were \$1 million as of December 31, 2010 and 2009.

(15) Common Shareholder's Equity

In January 2011, PacifiCorp declared a dividend of \$275 million payable to PPW Holdings LLC, a direct subsidiary of MEHC on February 28, 2011.

Through PPW Holdings LLC, MEHC is the sole shareholder of PacifiCorp's common stock. The state regulatory orders that authorized MEHC's acquisition of PacifiCorp contain restrictions on PacifiCorp's ability to pay dividends to the extent that they would reduce PacifiCorp's common stock equity below specified percentages of defined capitalization.

As of December 31, 2010, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings LLC or MEHC without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 46.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. This minimum level of common equity declines to 45.25% for the year ending December 31, 2011 and 44% thereafter. The terms of this commitment treat 50% of PacifiCorp's remaining balance of preferred stock in existence prior to the acquisition of PacifiCorp by MEHC as common equity. As of December 31, 2010, PacifiCorp's actual common stock equity percentage, as calculated under this measure, was 55.8%, and PacifiCorp would have been permitted to dividend \$2.320 billion under this commitment.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings LLC or MEHC if PacifiCorp's unsecured debt rating is BBB- or lower by Standard & Poor's Rating Services or Fitch Ratings or Baa3 or lower by Moody's Investor Service, as indicated by two of the three rating services. As of December 31, 2010, PacifiCorp's unsecured debt rating was A- by Standard & Poor's Rating Services, BBB+ by Fitch Ratings and Baa1 by Moody's Investor Service.

PacifiCorp is also subject to a maximum debt-to-total capitalization percentage under various financing agreements as further discussed in Notes 8 and 9.

(16) Components of Accumulated Other Comprehensive Loss, Net

Accumulated other comprehensive loss attributable to PacifiCorp, net consists of unrecognized amounts on retirement benefits of \$7 million, net of tax of \$4 million, and \$6 million, net of tax of \$3 million, as of December 31, 2010 and 2009, respectively.

(17) Variable-Interest Entities

PacifiCorp holds an undivided interest in 50% of the 474-MW Hermiston generating facility (refer to Note 4), dictates when the generating facility operates, procures 100% of the natural gas for the generating facility and subsequently receives 100% of the generated electricity, 50% of which is acquired through a long-term power purchase agreement. As a result, PacifiCorp holds a variable interest in the joint owner of the remaining 50% of the facility and is the primary beneficiary. PacifiCorp has been unable to obtain the information necessary to consolidate the entity because the entity has not agreed to supply the information due to the lack of a contractual obligation to do so. PacifiCorp continues to request from the entity the information necessary to perform the consolidation; however, no information has yet been provided by the entity. Cost of the electricity purchased from the joint owner was \$37 million during the year ended December 31, 2010 and \$36 million during each of the years ended December 31, 2009 and 2008. The entity is operated by the equity owners and PacifiCorp has no risk of loss in relation to the entity in the event of a disaster.

As discussed in Note 2, Bridger Coal was deconsolidated effective January 1, 2010 and is now accounted for under the equity method. PacifiCorp holds a two-thirds interest in Bridger Coal, which supplies coal to the Jim Bridger generating facility that is owned proportionately by PacifiCorp and PacifiCorp's joint venture partner in Bridger Coal. PacifiCorp purchases two-thirds of the coal produced by Bridger Coal, while the remaining coal is purchased by the joint venture partner. The power to direct the activities that most significantly impact Bridger Coal's economic performance are shared with the joint venture partner. Refer to Note 18 for information regarding related party transactions with Bridger Coal.

(18) Related-Party Transactions

PacifiCorp has an intercompany administrative services agreement with its indirect parent company, MEHC and its subsidiaries. Expenses charged to PacifiCorp under this agreement totaled \$9 million during each of the years ended December 31, 2010, 2009 and 2008. MEHC also pays certain third-party expenses on behalf of PacifiCorp that are reimbursed by PacifiCorp. These reimbursements were \$2 million, \$1 million and \$- million during the years ended December 31, 2010, 2009 and 2008, respectively. Payables associated with these administrative and third-party expenses were \$1 million and \$2 million as of December 31, 2010 and 2009, respectively. PacifiCorp also receives payments for services performed by PacifiCorp for MEHC and its affiliates, as well as for reimbursement of certain expenses. Services performed by PacifiCorp for MEHC and its affiliates primarily relate to administrative and technology services and direct-assigned employees. During the years ended December 31, 2010, 2009 and 2008, these services and expense reimbursements were \$3 million, \$1 million and \$2 million, respectively. Receivables associated with these activities were \$1 million and \$- million as of December 31, 2010 and 2009, respectively.

PacifiCorp also engages in various transactions with several subsidiaries of MEHC in the ordinary course of business. Services provided by these affiliates in the ordinary course of business and charged to PacifiCorp relate to the transportation of natural gas and relocation services. These expenses totaled \$5 million, \$3 million and \$6 million during the years ended December 31, 2010, 2009 and 2008, respectively. Payables associated with these expenses were \$- million and \$1 million as of December 31, 2010 and 2009, respectively.

PacifiCorp has long-term transportation contracts with BNSF Railway Company ("BNSF"), which became an indirect wholly owned subsidiary of Berkshire Hathaway, PacifiCorp's ultimate parent company, in February 2010. Transportation costs under these contracts were \$30 million, \$29 million and \$32 million during the years ended December 31, 2010, 2009 and 2008, respectively. As of December 31, 2010 and 2009, PacifiCorp had \$2 million and \$1 million of accounts payable to BNSF outstanding under these contracts, including indirect payables related to a jointly owned facility.

PacifiCorp participates in a captive insurance program provided by MEHC Insurance Services Ltd. ("MISL"), a wholly owned subsidiary of MEHC. MISL covers all or significant portions of the property damage and liability insurance deductibles in many of PacifiCorp's current policies, as well as overhead distribution and transmission line property damage. PacifiCorp has no equity interest in MISL and has no obligation to contribute equity or loan funds to MISL. Premium amounts were established in March 2006 based on a combination of actuarial assessments and market rates to cover loss claims, administrative expenses and appropriate reserves, but as a result of regulatory commitments were capped through December 31, 2010. Certain costs associated with the program are prepaid and amortized over the policy coverage period expiring March 20, 2011. Premium expenses were \$7 million during each of the years ended December 31, 2010, 2009 and 2008. Prepayments to MISL were \$2 million as of December 31, 2010 and 2009. Receivables for claims were \$12 million and \$10 million as of December 31, 2010 and 2009, respectively. Proceeds from claims were \$14 million, \$17 million and \$10 million during the years ended December 31, 2010, 2009 and 2008, respectively.

PacifiCorp is party to a tax-sharing agreement and is part of the Berkshire Hathaway United States federal income tax return. As of December 31, 2010 and 2009, income taxes receivable from MEHC were \$345 million and \$249 million, respectively.

PacifiCorp transacts with its equity investees, Bridger Coal and Trapper Mining Inc. Refer to Note 2 for additional information regarding Bridger Coal. During the year ended December 31, 2010, PacifiCorp charged Bridger Coal \$4 million for administrative support and management services provided by PacifiCorp to Bridger Coal. Receivables for these services, as well as for certain expenses paid by PacifiCorp and reimbursed by Bridger Coal, were \$3 million as of December 31, 2010. Services provided by equity investees and charged to PacifiCorp primarily relate to coal purchases. During the year ended December 31, 2010, coal purchases from PacifiCorp's equity investees totaled \$141 million. Payables to PacifiCorp's equity investees were \$17 million as of December 31, 2010.

(19) Supplemental Cash Flows Information

The summary of supplemental cash flows information for the years ended December 31 is as follows (in millions):

	<u>2010</u>	<u>2009</u>	<u>2008</u>
Interest paid, net of amounts capitalized	\$ 331	\$ 325	\$ 280
Income taxes received, net	<u>\$ 395</u>	<u>\$ 252</u>	<u>\$ 53</u>
Supplemental disclosure of non-cash investing and financing activities:			
Property, plant and equipment additions in accounts payable	\$ 216	\$ 251	\$ 405
Property, plant and equipment acquired under capital lease obligations	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 17</u>

(20) Unaudited Quarterly Operating Results (in millions)

	<u>Three-Month Periods Ended</u>			
	<u>March 31, 2010</u>	<u>June 30, 2010</u>	<u>September 30, 2010</u>	<u>December 31, 2010</u>
Operating revenue	\$ 1,106	\$ 1,052	\$ 1,165	\$ 1,109
Operating income	251	269	280	236
Net income	136	150	156	124
Net income attributable to PacifiCorp	136	150	156	124

	<u>Three-Month Periods Ended</u>			
	<u>March 31, 2009</u>	<u>June 30, 2009</u>	<u>September 30, 2009</u>	<u>December 31, 2009</u>
Operating revenue	\$ 1,116	\$ 1,016	\$ 1,146	\$ 1,179
Operating income	259	228	293	280
Net income	126	110	166	148
Net income attributable to PacifiCorp	123	110	162	147

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

At the end of the period covered by this Annual Report on Form 10-K, PacifiCorp carried out an evaluation, under the supervision and with the participation of PacifiCorp's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), of the effectiveness of the design and operation of PacifiCorp's disclosure controls and procedures (as defined in Rule 13a-15(e) promulgated under the Securities and Exchange Act of 1934, as amended). Based upon that evaluation, PacifiCorp's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), concluded that PacifiCorp's disclosure controls and procedures were effective to ensure that information required to be disclosed by PacifiCorp in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and is accumulated and communicated to management, including PacifiCorp's Chief Executive Officer (principal executive officer) and Chief Financial Officer (principal financial officer), or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. There has been no change in PacifiCorp's internal control over financial reporting during the quarter ended December 31, 2010 that has materially affected, or is reasonably likely to materially affect, PacifiCorp's internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Management of PacifiCorp is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in the Securities Exchange Act of 1934 Rule 13a-15(f). Under the supervision and with the participation of PacifiCorp's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), PacifiCorp's management conducted an evaluation of the effectiveness of PacifiCorp's internal control over financial reporting as of December 31, 2010 as required by the Securities Exchange Act of 1934 Rule 13a-15(c). In making this assessment, PacifiCorp's management used the criteria set forth in the framework in "Internal Control - Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the evaluation conducted under the framework in "Internal Control - Integrated Framework," PacifiCorp's management concluded that PacifiCorp's internal control over financial reporting was effective as of December 31, 2010.

PacifiCorp
February 28, 2011

Item 9B. Other Information

Coal Mine Safety Disclosures Required by the Dodd-Frank Wall Street Reform and Consumer Protection Act

The operation of PacifiCorp's coal mines and coal processing facilities is regulated by the Federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 ("Mine Safety Act"). MSHA inspects PacifiCorp's coal mines and coal processing facilities on a regular basis and may issue citations, notices, orders, or any combination thereof, when it believes a violation has occurred under the Mine Safety Act. For citations, monetary penalties are assessed by MSHA. Citations, notices and orders can be contested and appealed and the severity and assessment of penalties may be reduced or, in some cases, dismissed through the appeal process.

The table below summarizes the total number of citations, notices and orders issued and penalties assessed by MSHA for each coal mine or coal processing facility operated by PacifiCorp under the indicated provisions of the Mine Safety Act during the three- and six-month periods ended December 31, 2010. Legal actions pending before the Federal Mine Safety and Health Review Commission, which are not exclusive to citations, notices, orders and penalties assessed by MSHA, are as of December 31, 2010. Closed or idled mines have been excluded from the table below as no citations, orders or notices were issued for such mines during the three- and six-month periods ended December 31, 2010. In addition, there were no fatalities at PacifiCorp's coal mines or coal processing facilities during the three- and six-month periods ended December 31, 2010.

Coal Mine or Coal Processing Facility	Mine Safety Act						Total Value of Proposed MSHA Assessments (in thousands)	Legal Actions Pending
	Section 104 (a) Significant & Substantial Citations ⁽¹⁾	Section 104(b) Orders ⁽²⁾	Section 104(d) Citations & Orders ⁽³⁾	Section 110(b)(2) Citations ⁽⁴⁾	Section 107(a) Immlnent Danger Orders ⁽⁵⁾	Section 104(e) Notice ⁽⁶⁾		
Three-month period ended December 31, 2010								
Deer Creek	3	—	—	—	—	—	\$ 44	17
Bridger (surface)	2	—	—	—	—	—	3	6
Bridger (underground)	7	—	—	—	—	—	48	17
Cottonwood Preparatory Plant	—	—	—	—	—	—	—	—
Wyodak Coal Crushing Facility	1	—	—	—	—	—	—	—
Six-month period ended December 31, 2010								
Deer Creek	13	—	1	—	—	—	\$ 84	17
Bridger (surface)	4	—	—	—	—	—	7	6
Bridger (underground)	16	—	—	—	1	—	90	17
Cottonwood Preparatory Plant	—	—	—	—	—	—	—	—
Wyodak Coal Crushing Facility	1	—	—	—	—	—	—	—

- (1) For alleged violations of a mining safety standard or regulation where there exists a reasonable likelihood that the hazard contributed to or will result in an injury or illness of a reasonably serious nature.
- (2) For alleged failure to totally abate the subject matter of a Mine Safety Act section 104(a) citation within the period specified in the citation.
- (3) For an alleged unwarrantable failure (i.e., aggravated conduct constituting more than ordinary negligence) to comply with a mining safety standard or regulation.
- (4) For alleged flagrant violations (i.e., reckless or repeated failure to make reasonable efforts to eliminate a known violation of a mandatory health or safety standard that substantially and proximately caused, or reasonably caused, or reasonably could have been expected to cause, death or serious bodily injury).
- (5) The total number of imminent danger orders (i.e., the existence of any condition or practice in a coal or other mine which could reasonably be expected to cause death or serious physical harm before such condition or practice can be abated).
- (6) For a pattern, or the potential to have a pattern, of violations of mandatory health or safety standards that are of such nature as could have significantly and substantially contributed to the cause and effect of coal or other mine health or safety hazards.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

PacifiCorp is an indirect subsidiary of MEHC and its directors consist of executive management from both MEHC and PacifiCorp. Each director was elected based on individual responsibilities, experience in the energy industry and functional expertise. There are no family relationships among the executive officers, nor any arrangements or understandings between any executive officer and any other person pursuant to which the executive officer was appointed. Set forth below is certain information, as of January 31, 2011, with respect to each of the current directors and executive officers of PacifiCorp:

Gregory E. Abel, 48, Chairman of the Board of Directors and Chief Executive Officer of PacifiCorp since 2006. Mr. Abel has been Chief Executive Officer of MEHC since 2008, director since 2000, President since 1998, and was Chief Operating Officer from 1998 to 2008. Mr. Abel joined MEHC in 1992 and has extensive executive management experience in the energy industry.

Douglas L. Anderson, 52, Director. Mr. Anderson has been a director of PacifiCorp since 2006 and Senior Vice President, General Counsel and Corporate Secretary of MEHC since 2001. Mr. Anderson joined MEHC in 1993 and has significant legal experience, including expertise in corporate governance; mergers and acquisitions; and ethics and compliance programs.

Micheal G. Dunn, 45, President of PacifiCorp Energy and director of PacifiCorp since February 2010; President of Kern River Gas Transmission Company ("Kern River"), an indirect subsidiary of MEHC, from 2007 to January 2010; and Vice President of Operations, Information Technology and Engineering, of Kern River from 2005 to 2007. Mr. Dunn joined Kern River in 1990 and has significant operational, engineering and leadership expertise in the energy industry, including managing large construction projects and asset management.

Brent E. Gale, 59, Director. Mr. Gale has been a director of PacifiCorp and Senior Vice President, Regulation and Legislation, of MEHC since 2006; and was Senior Vice President, Legislation and Regulation, of MidAmerican Energy Company, an indirect subsidiary of MEHC, from 2004 to 2006. Mr. Gale has been employed by MEHC and its predecessor companies since 1976 and has extensive regulatory experience in the utility industry at both the federal and state levels.

Patrick J. Goodman, 44, Director. Mr. Goodman has been a director of PacifiCorp since 2006 and Senior Vice President and Chief Financial Officer of MEHC since 1999. Mr. Goodman joined MEHC in 1995 and has significant financial experience, including expertise in mergers and acquisitions; accounting; treasury; and tax functions.

Natalie L. Hocken, 41, Vice President and General Counsel of Pacific Power and director of PacifiCorp since 2007 and Assistant General Counsel of PacifiCorp from 2005 to 2007. Ms. Hocken joined PacifiCorp in 2002 and has significant legal experience in the utility industry, including expertise in litigation and federal and state regulatory compliance.

Mark C. Moench, 55, Senior Vice President and General Counsel of PacifiCorp since 2007; director of PacifiCorp and Senior Vice President and General Counsel of Rocky Mountain Power since 2006; Senior Vice President, Legal, of MEHC from 2005 to 2006; and Vice President and General Counsel of Kern River from 2002 to 2005. Mr. Moench has significant experience regarding federal and state regulation; mergers and acquisitions; and transmission permitting.

R. Patrick Reiten, 49, President of Pacific Power and director of PacifiCorp since 2006. Mr. Reiten served as President and Chief Executive Officer of PNGC Power from 2002 to 2006, after joining PNGC Power in 1993. Mr. Reiten has significant operational, public policy and leadership experience in the energy industry, including expertise in transmission and distribution systems; community relations; and regulatory matters.

Douglas K. Stuver, 47, Senior Vice President and Chief Financial Officer of PacifiCorp since 2008, Controller of PacifiCorp Energy from 2006 to 2008 and Controller of PacifiCorp's commercial and trading business unit from 2004 to 2006. Mr. Stuver joined PacifiCorp in 2004 and has significant financial and energy risk management experience.

A. Richard Walje, 59, President of Rocky Mountain Power since 2006, Executive Vice President from 2004 to 2006, director of PacifiCorp since 2001, and Chief Information Officer from 2000 to 2006. Mr. Walje joined PacifiCorp in 1986 and has significant operational, engineering, and leadership experience in the utility industry, including expertise in transmission and distribution systems; customer services; and information technology.

Board's Role in the Risk Oversight Process

PacifiCorp's Board of Directors is comprised of a combination of MEHC senior executives and PacifiCorp senior management who have direct and indirect responsibility for the management and oversight of risk. PacifiCorp's Board of Directors has not established a separate risk management and oversight committee.

Audit Committee and Audit Committee Financial Expert

During the year ended December 31, 2010, and as of the date of this Annual Report on Form 10-K, PacifiCorp's Board of Directors did not have an audit committee. PacifiCorp is not required to have an audit committee as its common stock is indirectly and wholly owned by MEHC and its Board of Directors consists primarily of MEHC and PacifiCorp employees. However, the audit committee of MEHC acts as the audit committee for PacifiCorp.

Code of Ethics

PacifiCorp has adopted a code of ethics that applies to its principal executive officer, its principal financial and accounting officer, or persons acting in such capacities, and certain other covered officers. The code of ethics is incorporated by reference in the exhibits to this Annual Report on Form 10-K.

Item 11. Executive Compensation

Compensation Discussion and Analysis

Compensation Philosophy and Overall Objectives

We and our indirect parent company, MidAmerican Energy Holdings Company, or MEHC, believe that the compensation paid to each of our Chief Executive Officer, or CEO, our Chief Financial Officer, or CFO, and our three other most highly compensated executive officers, to whom we refer collectively as our Named Executive Officers, or NEOs, should be closely aligned with our overall performance, and each NEO's contribution to that performance, on both a short- and long-term basis, and that such compensation should be sufficient to attract and retain highly qualified leaders who can create significant value for our organization. Our compensation programs are designed to provide our NEOs meaningful incentives for superior corporate and individual performance. Performance is evaluated on a subjective basis within the context of both financial and non-financial objectives that we believe contribute to our long-term success, among which are customer service, operational excellence, financial strength, employee commitment and safety, environmental respect and regulatory integrity.

How is Compensation Determined

Our compensation committee consists solely of the Chairman of our Board of Directors, Mr. Gregory E. Abel. Mr. Abel also serves as our CEO and as MEHC's President and Chief Executive Officer. Mr. Abel is employed by MEHC and receives no direct compensation from us. Mr. Abel is responsible for the establishment and oversight of our compensation policy for our NEOs and for approving base pay increases, incentive and performance awards, off-cycle pay changes, and participation in other employee benefit plans and programs.

Our criteria for assessing executive performance and determining compensation in any year is inherently subjective and is not based upon specific formulas or weighting of factors. Given the uniqueness of each NEO's duties, we do not specifically use other companies as benchmarks when establishing our NEOs' compensation.

Discussion and Analysis of Specific Compensation Elements

Base Salary

We determine base salaries for all of our NEOs, other than Mr. Abel, by reviewing our overall performance and each NEO's performance, the value each NEO brings to us and general labor market conditions. While base salary provides a base level of compensation intended to be competitive with the external market, the annual base salary adjustment for each NEO, other than Mr. Abel, is determined on a subjective basis after consideration of these factors and is not based on target percentiles or other formal criteria. All merit increases are approved by Mr. Abel and take effect in the last payroll period of each year. An increase or decrease in base salary may also result from a promotion or other significant change in a NEO's responsibilities during the year. In 2010, none of the NEOs received base salary increases. There have been no base salary changes for our NEOs since the December 26, 2008 merit increase.

Short-Term Incentive Compensation

The objective of short-term incentive compensation is to reward the achievement of significant annual corporate and business unit goals while also providing NEOs with competitive total cash compensation.

Annual Incentive Plan

Under our Annual Incentive Plan, or AIP, all NEOs, other than Mr. Abel, are eligible to earn an annual discretionary cash incentive award, which is determined on a subjective basis at Mr. Abel's sole discretion and is not based on a specific formula or cap. Mr. Abel considers a variety of factors in determining each NEO's performance award including the NEO's performance, our overall performance and each NEO's contribution to that overall performance. Mr. Abel evaluates performance using financial and non-financial principles, including customer service; operational excellence; financial strength; employee commitment and safety; environmental respect; and regulatory integrity, as well as the NEO's response to issues and opportunities that arise during the year. No factor was individually material to Mr. Abel's determination regarding the amounts paid to each NEO under the AIP for 2010. Approved awards are paid prior to year-end.

Performance Awards

In addition to the annual awards under the AIP, we may grant cash performance awards periodically during the year to one or more NEOs, other than Mr. Abel, to reward the accomplishment of significant non-recurring tasks or projects. These awards are discretionary and are approved by Mr. Abel. There were no performance awards granted to our NEOs during 2010.

Long-Term Incentive Compensation

The objective of long-term incentive compensation is to retain NEOs, reward their exceptional performance and motivate them to create long-term, sustainable value. Our current long-term incentive compensation program is cash-based. We do not utilize stock options or other forms of equity-based awards.

Long-Term Incentive Partnership Plan

The MidAmerican Energy Holdings Company Long-Term Incentive Partnership Plan, or LTIP, is designed to retain key employees and to align our interests and the interests of the participating employees. All of our NEOs, other than Mr. Abel, participate in the LTIP. The LTIP provides for annual discretionary awards based upon significant accomplishments by the individual participants and the achievement of the financial and non-financial objectives previously described. The goals are developed with the objective of being attainable with a sustained, focused and concerted effort and are determined and communicated in January of each plan year. Participation is discretionary and is determined by MEHC's Chairman of the Board of Directors and its Chief Executive Officer who recommend awards to the MEHC compensation committee annually in the fourth quarter. Except for limited situations of extraordinary performance, awards are capped at 1.5 times base salary and finalized in the first quarter of the following year. These cash-based awards are subject to mandatory deferral and equal annual vesting over a five-year period starting in the performance year. Participants allocate the value of their deferral accounts among various investment alternatives. Gains or losses may be incurred based on investment performance. Participating NEOs may elect to defer all or a part of the award or receive payment in cash after the five-year mandatory deferral and vesting period. Vested balances (including any investment profits or losses thereon) of terminating participants are paid at the time of termination.

Other Employee Benefits

Supplemental Executive Retirement Plan

Our Supplemental Executive Retirement Plan, or SERP, provides additional retirement benefits to participants. Mr. Walje was the only NEO who participated in our SERP during 2010, and we have no plans to add new participants in the future. The SERP provides monthly retirement benefits of 50% of final average pay plus 1% of final average pay for each fiscal year that we meet certain performance goals set for such fiscal year. The maximum benefit is 65% of final average pay. A participant's final average pay equals the 60 consecutive months of highest pay out of the last 120 months, and pay for this purpose includes salary and annual incentive plan payments reflected in the Summary Compensation Table below.

Deferred Compensation Plan

Our Executive Voluntary Deferred Compensation Plan, or DCP, provides a means for all NEOs, other than Mr. Abel, to make voluntary deferrals of up to 50% of base salary and 100% of short-term incentive compensation awards. We include the DCP as part of the participating NEO's overall compensation in order to provide a comprehensive, competitive package. The deferrals and any investment returns grow on a tax-deferred basis. Amounts deferred under the DCP receive a rate of return based on the returns of any combination of eight investment options offered under the DCP and selected by the participant. The plan allows participants to choose from three forms of distribution. The plan permits us to make discretionary contributions on behalf of participants.

Potential Payments Upon Termination

Our NEOs (excluding Mr. Abel) are not entitled to severance or enhanced benefits upon termination of employment or change-in-control. Please refer to MEHC's Annual Report on Form 10-K for the year ended December 31, 2010 (File No. 001-14881) for information about potential post-termination payments to Mr. Abel. However, upon any termination of employment, our other NEOs would be entitled to the vested balances in the Retirement Plan, SERP, LTIP and the DCP.

Compensation Committee Report

Mr. Abel, our Chairman and Chief Executive Officer and sole member of our compensation committee, has reviewed and discussed the Compensation Discussion and Analysis with management and, based on this review and discussion, has recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

Summary Compensation Table

The following table sets forth information regarding compensation earned by each of our NEOs during the years indicated:

Name and Principal Position	Year	Base Salary ⁽¹⁾	Bonus ⁽²⁾	Change in Pension Value and Nonqualified Deferred Compensation Earnings ⁽³⁾	All Other Compensation ⁽⁴⁾	Total ⁽⁵⁾
Gregory E. Abel ⁽⁶⁾	2010	\$ —	\$ —	\$ —	\$ —	\$ —
Chairman and	2009	—	—	—	—	—
Chief Executive Officer	2008	—	—	—	—	—
A. Richard Walje	2010	357,150	721,364	548,195	35,096	1,661,805
President, Rocky Mountain Power	2009	351,900	583,217	733,231	54,617	1,722,965
	2008	345,000	328,769	267,902	10,283	951,954
R. Patrick Reiten	2010	265,740	828,466	445	36,796	1,131,447
President, Pacific Power	2009	265,740	623,417	355	35,892	925,404
	2008	258,000	353,472	11,548	24,462	647,482
Michael G. Dunn ⁽⁷⁾	2010	230,114	355,000	12,925	24,638	622,677
President, PacifiCorp Energy	2009	—	—	—	—	—
	2008	—	—	—	—	—
Doug K. Stuver	2010	233,525	268,455	8,014	34,460	544,454
Senior Vice President and	2009	228,800	231,033	12,623	39,945	512,401
Chief Financial Officer	2008	215,499	133,140	28,928	8,817	386,384

- (1) Includes a one-time increase to base pay for Mr. Walje and Mr. Stuver in the amount of \$9,000 and \$8,100, respectively, for the annual value of the vehicle allowance program that was discontinued in June 2010.
- (2) Consists of annual cash incentive awards earned pursuant to the AIP for our NEOs, performance awards earned related to non-routine projects and the vesting of LTIP awards and associated vested earnings. The breakout for 2010 is as follows:

	AIP	Performance Award	LTIP ^(a)		Total
			Vested Awards	Vested Earnings	
A. Richard Walje	\$ 200,000	\$ —	\$ 360,577	\$ 160,787	\$ 521,364
R. Patrick Reiten	275,000	—	405,717	147,749	553,466
Michael G. Dunn	260,000	—	95,000	—	95,000
Douglas K. Stuver	85,000	—	134,315	49,140	183,455

- (a) The LTIP vested awards and vested earnings columns exclude any amounts related to Mr. Dunn's awards granted and vested prior to him transferring to PacifiCorp.

The ultimate payouts of LTIP awards are undeterminable as the amounts to be paid out may increase or decrease depending on investment performance. Net income, the net income target goal and the matrix below were used in determining the gross amount of the LTIP award available to the participants. Net income for determining the award and the award itself are subject to discretionary adjustment by MEHC's Chairman of the Board of Directors, its Chief Executive Officer and its compensation committee. In 2010, the gross award and per-point value were determined based on the overall achievement of our financial and non-financial objectives.

MEHC Net Income	Award
Less than or equal to net income target goal	None
Exceeds net income target goal by 0.01% - 3.25%	15% of excess
Exceeds net income target goal by 3.251% - 6.50%	15% of the first 3.25% excess; 25% of excess over 3.25%
Exceeds net income target goal by more than 6.50%	15% of the first 3.25% excess; 25% of the next 3.25% excess; 35% of excess over 6.50%

Points are allocated among plan participants either as initial points or year-end performance points. A nominating committee recommends the point allocation, subject to approval by MEHC's Chairman of the Board of Directors and its Chief Executive Officer, based upon a discretionary evaluation of individual achievement of financial and non-financial goals previously described herein. A participant's award equals the participant's allocated points multiplied by the final per-point value, capped at 1.5 times base salary except in extraordinary circumstances.

- (3) Amounts are based upon the aggregate increase in the actuarial present value of all qualified and nonqualified defined benefit plans, which include the SERP and the Retirement Plan, as applicable. Amounts are computed using assumptions consistent with those used in preparing the related pension disclosures in our Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and are as of the pension plans' measurement dates. No participant in our DCP earned "above market" or "preferential" earnings on amounts deferred.
- (4) Amounts consist of Employee Savings Plan ("401(k) Plan") contributions we paid on behalf of the NEOs and registrant contributions to the DCP, as noted in the Nonqualified Deferred Compensation table. Items required to be reported and quantified are as follows: Mr. Walje - 401(k) contributions of \$32,500; Mr. Reiten - 401(k) contributions of \$34,300; Mr. Dunn - 401(k) contributions of \$11,430 and DCP contributions of \$13,208; and Mr. Stuver - 401(k) contributions of \$32,500.
- (5) Any amounts voluntarily deferred by the NEO, if applicable, are included in the appropriate column in the Summary Compensation Table.
- (6) Mr. Abel receives no direct compensation from us. We reimburse MEHC for the cost of Mr. Abel's time spent on matters supporting us, including compensation paid to him by MEHC, pursuant to an intercompany administrative services agreement among MEHC and its subsidiaries. Please refer to MEHC's Annual Report on Form 10-K for the year ended December 31, 2010 (File No. 001-14881) for executive compensation information for Mr. Abel.
- (7) On January 13, 2010, Mr. Dunn was elected President of PacifiCorp Energy effective February 1, 2010. Mr. Dunn previously served as President of Kern River, an indirect subsidiary of MEHC.

Pension Benefits

The following table sets forth certain information regarding the defined benefit pension plan accounts held by each of our NEOs as of December 31, 2010:

Name	Plan name	Number of years of credited service	Present value of accumulated benefits ⁽¹⁾
Gregory E. Abel	Retirement	n/a	\$ —
A. Richard Walje	SERP	25 years	2,672,161
	Retirement	23 years	867,706
R. Patrick Reiten	Retirement	2 years	15,832
Michael G. Dunn ⁽²⁾	Retirement	1 year	12,925
Douglas K. Stuver	Retirement	5 years	85,754

(1) Amounts are computed using assumptions consistent with those used in preparing the related pension disclosures in our Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and are as of December 31, 2010, which is the measurement date for the plans. Single life annuities were assumed for the SERP calculations of the present value of accumulated benefits. For the Retirement Plan calculations of the present value of accumulated benefits, the following assumptions were used: 50.0% lump sum and 50.0% single life annuity. The present value assumptions used in calculating the present value of accumulated benefits for the SERP were as follows: a discount rate of 5.35%; an expected retirement age of 60; and postretirement mortality using the RP-2000 table projected to 2011. The present value assumptions used in calculating the present value of accumulated benefits for the Retirement Plan were as follows: a discount rate of 5.35%; an expected retirement age of 65; postretirement mortality using the RP-2000 table projected to 2011; a lump sum interest rate of 5.35%; and lump sum mortality using the Internal Revenue Code §417(c)(3) Applicable Mortality Table for 2011.

(2) The number of years of service and the present value of accumulated benefits for Mr. Dunn represents his service as a PacifiCorp employee only and does not include any vested benefits earned under Kern River.

The SERP provides monthly retirement benefits of 50% of final average pay plus 1% of final average pay for each fiscal year that we meet certain performance goals set for such fiscal year. The maximum benefit is 65% of final average pay. A participant's final average pay equals the 60 consecutive months of highest pay out of the last 120 months, and pay for this purpose includes salary and annual incentive plan payments reflected in the Summary Compensation Table above. Mr. Walje has met the five-year participation requirement under the plan for early retirement eligibility. Mr. Walje's SERP benefit will be reduced by a portion of his Social Security benefits, his regular retirement benefit under the Retirement Plan, and 0.25% for each month benefit commencement precedes age 60.

We have adopted a non-contributory defined benefit pension plan, or the Retirement Plan, for the majority of our employees, other than employees subject to collective bargaining agreements that do not provide for coverage. Through May 31, 2007, participants earned benefits at retirement payable for life based on length of service through May 31, 2007 and average pay in the 60 consecutive months of highest pay out of the 120 months prior to May 31, 2007, and pay for this purpose included salary and annual incentive plan payments up to 10% of base salary, but were limited to the Internal Revenue Code amounts specified in §401(a)(17). Benefits were based on 1.3% of final average pay plus 0.65% of final average pay in excess of covered compensation (as defined in Internal Revenue Code §401(1)(5)(E)) times years of service.

The Retirement Plan was restated effective June 1, 2007 to change from a traditional final-average-pay formula as described above to a cash balance formula for non-union participants. Benefits under the final-average-pay formula were frozen as of May 31, 2007, and no future benefits will accrue under that formula for non-union participants. Under the cash balance formula, benefits are based on pay credits to each participant's account of 6.5% (5.0% for employees hired after June 30, 2006 and before January 1, 2008) of eligible compensation plus 4.0% of eligible compensation in excess of compensation subject to Federal Insurance Contributions Act withholding (where such salary and incentive amounts are reduced for Internal Revenue Code §401(a)(17) limits). However, the 4.0% portion of the formula was eliminated on August 1, 2009 and therefore for 2009 the 4.0% benefit was based on eligible compensation for the first seven months that exceeded \$62,300 (7/12th of \$106,800). Interest is also credited to each participant's account. Employees who were age 40 or older as of May 31, 2007 receive certain additional transition pay credits for five years from the effective date of the plan restatement. Effective January 1, 2009, non-union participants were offered the option to continue to receive pay credits in the Retirement Plan as of December 31, 2008 or receive equivalent fixed 401(k) contributions.

Participants in the Retirement Plan are entitled to receive full benefits upon retirement after age 65. Such participants are also entitled to receive reduced benefits upon early retirement after age 55 with at least five years of service or when age plus years of service equals 75. Participants in the SERP are entitled to receive full benefits upon retirement after age 60. Such participants are also entitled to receive reduced benefits upon early retirement after age 55 with at least five years of SERP participation or after age 50 with at least 15 years of service and five years of SERP participation.

In 2008, non-union employee participants in the Retirement Plan were offered the option to continue to receive pay credits in the Retirement Plan or receive equivalent fixed contributions to the 401(k) plan, with any such election becoming effective January 1, 2009. Messrs. Walje, Reiten and Stuver elected the equivalent fixed 401(k) contribution option and, therefore, no longer receive pay credits in the Retirement Plan; however, they each continue to receive interest credits.

Nonqualified Deferred Compensation

The following table sets forth certain information regarding the DCP accounts held by each of our NEOs as of December 31, 2010:

Name	Executive contributions in 2010 ⁽¹⁾	Registrant contributions in 2010 ⁽²⁾	Aggregate earnings in 2010	Aggregate withdrawals/distributions	Aggregate balance as of December 31, 2010 ⁽³⁾
Gregory E. Abel	\$ —	\$ —	\$ —	\$ —	\$ —
A. Richard Walje	40,000	2,596	190,937	12,137	2,020,508
R. Patrick Reiten	346,651	1,960	—	—	348,611
Michael G. Dunn	13,000	13,208	126	—	26,334
Douglas K. Stuver	—	1,960	58	—	7,308

- (1) The contribution amounts shown for Messrs. Walje and Dunn are included in the 2010 total compensation reported for them in the Summary Compensation Table and are not additional earned compensation. The contribution amount shown for Mr. Reiten includes \$246,862 earned toward his 2006 LTIP award prior to 2010 and thus is not included in the 2010 total compensation reported for him in the Summary Compensation Table.
- (2) The contribution amounts shown for Messrs. Walje, Reiten, Dunn and Stuver are included in the 2010 total compensation reported for them in the Summary Compensation Table and are not additional earned compensation. The amounts were earned in 2010 but not contributed into the DCP until 2011.
- (3) The aggregate balance as of December 31, 2010 for Messrs. Walje and Stuver includes \$5,959 and \$5,290, respectively, of compensation previously reported in 2009 in the Summary Compensation Table, and \$189,000 and zero, respectively, of compensation previously reported in 2008 in the Summary Compensation Table.

Eligibility for our DCP is restricted to select management and highly compensated employees. The plan provides tax benefits to eligible participants by allowing them to defer compensation on a pretax basis, thus reducing their current taxable income. Deferrals and any investment returns grow on a tax-deferred basis, thus participants pay no income tax until they receive distributions. The DCP permits participants to make a voluntary deferral of up to 50% of base salary and 100% of short-term incentive compensation awards. All deferrals are net of social security taxes. Amounts deferred under the DCP receive a rate of return based on the returns of any combination of eight investment options offered by the plan and selected by the participant. Gains or losses are calculated daily, and returns are posted to accounts based on participants' fund allocation elections. Participants can change their fund allocations as of the end of any day on which the market is open.

The DCP allows participants to maintain three accounts based upon when they want to receive payments: retirement account, in-service account and education account. Both the retirement and in-service accounts can be distributed as lump sums or in up to 10 annual installments, except in the case of the four DCP transition accounts that allow for a grandfathered payout based on the previous deferred compensation plan distribution elections of lump sum, 5, 10 or 15 annual installments. Effective December 31, 2006, no new money may be deferred into the DCP transition accounts. The education account is distributed in four annual installments. If a participant leaves employment prior to retirement (age 55), all amounts in the participant's account will be paid out in a lump sum as soon as administratively practicable. Participants are 100% vested in their deferrals and any investment gains or losses recorded in their accounts.

Participants in our LTIP also have the option of deferring all or a part of those awards after the five-year mandatory deferral and vesting period. The provisions governing the deferral of LTIP awards are similar to those described for the DCP above.

Potential Payments Upon Termination

Our NEOs (excluding Mr. Abel) are not entitled to severance or enhanced benefits upon termination of employment or change-in-control. Please refer to MEHC's Annual Report on Form 10-K for the year ended December 31, 2010 (File No. 001-14881) for information about potential post-termination payments to Mr. Abel.

The following table sets forth the estimated enhancements to payments pursuant to the termination scenarios indicated. Payments or benefits that are not enhanced in form or amount upon the occurrence of a particular termination scenario, which include 401(k) and nonqualified deferred compensation account balances and those portions of long-term incentive payments and cash balance pension amounts that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2010, and are payable as lump sums unless otherwise noted.

Termination Scenario	Incentive ⁽¹⁾	Pension ⁽²⁾
Gregory E. Abel:		
Retirement, Voluntary and Involuntary With or Without Cause	\$ —	\$ —
Death and Disability	—	—
A. Richard Walje ⁽³⁾ :		
Retirement, Voluntary and Involuntary With or Without Cause	—	220,786
Death and Disability	761,785	220,786
R. Patrick Reiten:		
Retirement, Voluntary and Involuntary With or Without Cause	—	3,019
Death and Disability	970,665	3,019
Micheal G. Dunn:		
Retirement, Voluntary and Involuntary With or Without Cause	—	3,000
Death and Disability	380,000	3,000
Douglas K. Stuver:		
Retirement, Voluntary and Involuntary With or Without Cause	—	9,206
Death and Disability	362,739	9,206

- (1) Amounts represent the unvested portion of each NEO's LTIP account, which becomes 100% vested upon death or disability. For Mr. Dunn, this represents his unvested portion for service as a PacifiCorp employee only and does not include any vested benefits earned while employed by Kern River.
- (2) Pension values represent the excess of the present value of benefits payable under each termination scenario over the amount already reflected in the Pension Benefits table.
- (3) Mr. Walje has already met the retirement criteria, therefore his termination and death scenarios under the Retirement Plan are based on assuming 50% lump sum payout and 50% annuity.

Director Compensation Table

All of our directors serving in 2010 were employees of PacifiCorp, or in the case of Messrs. Anderson and Goodman, employees of MEHC, and did not receive additional compensation for service as a director. The following table excludes Messrs. Abel, Walje, Reiten and Dunn for whom compensation information is described in the Summary Compensation Table.

Name	Change in Pension Value and Nonqualified Deferred Compensation Earnings ⁽¹⁾	All Other Compensation ⁽²⁾	Total
Douglas L. Anderson	\$ —	\$ —	\$ —
Brent E. Gale	27,615	907,476	935,091
Patrick J. Goodman	—	—	—
Natalie L. Hocken	7,309	571,001	578,310
Mark C. Moench	26,047	526,311	552,358

(1) Amounts included in change in pension value and nonqualified deferred compensation earnings are based upon the aggregate increase in the actuarial present value of all qualified and nonqualified defined benefit plans, which include the SERP and the Retirement Plan, as applicable. Amounts are computed using assumptions consistent with those used in preparing the applicable pension disclosures included in our Notes to the Consolidated Financial Statements in Item 8 of this Form 10-K and are as of the pension plans' measurement dates. No participant in our DCP earned "above market" or "preferential" earnings on amounts deferred.

(2) Amounts shown for the year ended December 31, 2010, include:

- (i) Base salary in the amounts of \$287,000 for Mr. Gale, \$190,357 for Ms. Hocken and \$218,754 for Mr. Moench.
- (ii) Contributions to our 401(k) Plan of \$3,185 for Mr. Gale, \$29,466 for Ms. Hocken and \$9,555 for Mr. Moench.
- (iii) Life insurance premium paid by us on behalf of Mr. Gale in the amount of \$14,800.
- (iv) Annual cash incentive awards earned pursuant to the AIP for our directors, the vesting of LTIP awards and associated vested earnings for Mr. Gale, Ms. Hocken and Mr. Moench. The breakout of AIP and LTIP awards for 2010 is as follows:

	AIP	LTIP		
		Vested Awards	Vested Earnings	Total
Brent E. Gale	\$ 160,000	\$ 292,049	\$ 150,442	\$ 442,491
Natalie L. Hocken	135,000	149,635	66,543	216,178
Mark C. Moench	93,000	187,279	17,723	205,002

Compensation Committee Interlocks and Insider Participation

Mr. Abel is our Chairman of the Board of Directors and CEO and also the President and Chief Executive Officer of MEHC. None of our executive officers serves as a member of the compensation committee of any company that has an executive officer serving as a member of our Board of Directors. None of our executive officers serves as a member of the board of directors of any company (other than MEHC) that has an executive officer serving as a member of our compensation committee. See also Item 13 of this Annual Report on Form 10-K.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

We are a consolidated subsidiary of MEHC. Our common stock is indirectly owned by MEHC, 666 Grand Avenue, Des Moines, Iowa 50309. MEHC is a consolidated subsidiary of Berkshire Hathaway that, as of January 31, 2011, owns 89.85% of MEHC's common stock. The balance of MEHC's common stock is owned by Walter Scott, Jr. (along with family members and related entities), a member of MEHC's Board of Directors, and Gregory E. Abel, PacifiCorp's Chairman and Chief Executive Officer.

None of our executive officers or directors owns shares of our preferred stock. The following table sets forth certain information as of January 31, 2011 regarding the beneficial ownership of MEHC's common stock and the Class A and Class B shares of Berkshire Hathaway common stock held by each of our directors, executive officers and all of our directors and executive officers as a group as of January 31, 2011.

Beneficial Owner	MEHC		Berkshire Hathaway			
	Common Stock		Class A Common Stock		Class B Common Stock	
	Number of Shares Beneficially Owned ⁽¹⁾	Percentage of Class ⁽¹⁾	Number of Shares Beneficially Owned ⁽¹⁾	Percentage of Class ⁽¹⁾	Number of Shares Beneficially Owned ⁽¹⁾	Percentage of Class ⁽¹⁾
Gregory E. Abel ⁽²⁾	595,940	0.8%	1	*	1,930	*
Douglas L. Anderson	—	—	4	*	300	*
Michael G. Dunn	—	—	—	—	—	—
Brent E. Gale	—	—	—	—	—	—
Patrick J. Goodman	—	—	4	*	660	*
Natalie L. Hocken	—	—	—	—	—	—
Mark C. Moench ⁽³⁾	—	—	3	*	—	—
R. Patrick Reiten	—	—	—	—	—	—
Douglas K. Stuver	—	—	—	—	—	—
A. Richard Walje	—	—	—	—	—	—
All executive officers and directors as a group (10 persons)	595,940	0.8%	12	*	2,890	*

* Indicates beneficial ownership of less than one percent of all outstanding shares.

- (1) Includes shares which the listed beneficial owner is deemed to have the right to acquire beneficial ownership under Rule 13d-3(d) under the Securities Exchange Act, including, among other things, shares which the listed beneficial owner has the right to acquire within 60 days.
- (2) In accordance with a shareholders' agreement, as amended on December 7, 2005, based on an assumed value for MEHC's common stock and the closing price of Berkshire Hathaway common stock on January 31, 2011, Mr. Abel would be entitled to exchange his shares of MEHC common stock for either 1,120 shares of Berkshire Hathaway Class A stock or 1,676,651 shares of Berkshire Hathaway Class B stock. Assuming an exchange of all available MEHC shares into either Berkshire Hathaway Class A shares or Berkshire Hathaway Class B shares, Mr. Abel would beneficially own less than 1% of the outstanding shares of either class of stock.
- (3) Excludes 12 Class A shares and 15,000 Class B shares of Berkshire Hathaway common stock held by a family corporation and family limited partnership, as to which Mr. Moench disclaims beneficial ownership.

Other Matters

Pursuant to a shareholders' agreement, as amended on December 7, 2005, Mr. Abel is able to require Berkshire Hathaway to exchange any or all of his shares of MEHC common stock for shares of Berkshire Hathaway common stock. The number of shares of Berkshire Hathaway common stock to be exchanged is based on the fair market value of MEHC common stock divided by the closing price of the Berkshire Hathaway common stock on the day prior to the date of exchange.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Certain Relationships and Related Transactions

The Berkshire Hathaway Inc. Code of Business Conduct and Ethics and the MEHC Code of Business Conduct, or the Codes, which apply to all of our directors, officers and employees and those of our subsidiaries, generally govern the review, approval or ratification of any related-person transaction. A related-person transaction is one in which we or any of our subsidiaries participate and in which one or more of our directors, executive officers, holders of more than five percent of our voting securities or any of such persons' immediate family members have a direct or indirect material interest.

Under the Codes, all of our directors and executive officers (including those of our subsidiaries) must disclose to our legal department any material transaction or relationship that reasonably could be expected to give rise to a conflict with our interests. No action may be taken with respect to such transaction or relationship until approved by the legal department. For our chief executive officer and chief financial officer, prior approval for any such transaction or relationship must be given by Berkshire Hathaway's audit committee. In addition, prior legal department approval must be obtained before a director or executive officer can accept employment, offices or board positions in other for-profit businesses, or engage in his or her own business that raises a potential conflict or appearance of conflict with our interests.

Under an intercompany administrative services agreement we have entered into with MEHC and its other subsidiaries, the costs of certain administrative services provided by MEHC to us or by us to MEHC, or shared with MEHC and other subsidiaries, are directly charged or allocated to the entity receiving such services. This agreement has been filed with the utility regulatory commissions in the states where we serve retail customers. We also provide an annual report of all transactions with our affiliates to our state regulatory commissions, who have the authority to refuse recovery in rates for payments we make to our affiliates deemed to have the effect of subsidizing the separate business activities of MEHC or its other subsidiaries.

Refer to Note 18 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding related-party transactions.

Director Independence

Because our common stock is indirectly, wholly owned by MEHC, our Board of Directors consists primarily of MEHC and PacifiCorp employees and we are not required to have independent directors or audit, nominating or compensation committees consisting of independent directors.

Based on the standards of the New York Stock Exchange LLC, on which the common stock of our ultimate parent company, Berkshire Hathaway, is listed, our Board of Directors has determined that none of our directors are considered independent because of their employment by MEHC or PacifiCorp.

Item 14. Principal Accountant Fees and Services

The following table shows PacifiCorp's fees paid or accrued for audit and audit-related services and fees paid for tax and all other services rendered by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates (collectively, the "Deloitte Entities") for each of the last two years (in millions):

	2010	2009
Audit fees ⁽¹⁾	\$ 1.4	\$ 1.8
Audit-related fees ⁽²⁾	0.2	0.2
Tax fees ⁽³⁾	—	—
All other fees	—	—
Total aggregate fees billed	<u>\$ 1.6</u>	<u>\$ 2.0</u>

- (1) Audit fees include fees for the audit of PacifiCorp's consolidated financial statements and interim reviews of PacifiCorp's quarterly financial statements, audit services provided in connection with required statutory audits, and comfort letters, consents and other services related to SEC matters.
- (2) Audit-related fees primarily include fees for assurance and related services for any other statutory or regulatory requirements, audits of certain employee benefit plans and consultations on various accounting and reporting matters.
- (3) Tax fees include fees for services relating to tax compliance, tax planning and tax advice. These services include assistance regarding federal and state tax compliance, tax return preparation and tax audits.

The audit committee of MEHC reviewed and approved the services rendered by the Deloitte Entities in and for fiscal 2010 as set forth in the above table and concluded that the non-audit services were compatible with maintaining the principal accountant's independence. Under the Sarbanes-Oxley Act of 2002, all audit and non-audit services performed by the principal accountant require the approval in advance by the audit committee in order to assure that such services do not impair the principal accountant's independence from PacifiCorp. Accordingly, the audit committee has an Audit and Non-Audit Services Pre-Approval Policy (the "Policy") that sets forth the procedures and the conditions pursuant to which services to be performed by the principal accountant are to be pre-approved. Pursuant to the Policy, certain services described in detail in the Policy may be pre-approved on an annual basis together with pre-approved maximum fee levels for such services. The services eligible for annual pre-approval consist of services that would be included under the categories of Audit Fees, Audit-Related Fees and Tax Fees. If not pre-approved on an annual basis, proposed services must otherwise be separately approved prior to being performed by the principal accountant. In addition, any services that receive annual pre-approval but exceed the pre-approved maximum fee level also will require separate approval by the audit committee prior to being performed. The Policy does not delegate to management the audit committee's responsibilities to pre-approve services performed by the principal accountant.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements and Schedules

(i) Financial Statements:

Consolidated Financial Statements are included in Item 8.

(ii) Financial Statement Schedules:

All schedules have been omitted because they are either not applicable, not required or the information required to be set forth therein is included on the Consolidated Financial Statements or notes thereto.

(b) Exhibits

The exhibits listed on the accompanying Exhibit Index are filed as part of this Annual Report.

(c) Financial statements required by Regulation S-X, which are excluded from the Annual Report by Rule 14a-3(b).

Not applicable.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on this 28th day of February 2011.

PACIFICORP

/s/ Douglas K. Stuver

Douglas K. Stuver

Senior Vice President and Chief Financial Officer
(principal financial and accounting officer)

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

Signature	Title	Date
<u>/s/ Gregory E. Abel</u> Gregory E. Abel	Chairman of the Board of Directors and Chief Executive Officer (principal executive officer)	February 28, 2011
<u>/s/ Douglas K. Stuver</u> Douglas K. Stuver	Senior Vice President and Chief Financial Officer (principal financial and accounting officer)	February 28, 2011
<u>/s/ Douglas L. Anderson</u> Douglas L. Anderson	Director	February 28, 2011
<u>/s/ Micheal G. Dunn</u> Micheal G. Dunn	Director	February 28, 2011
<u>/s/ Brent E. Gale</u> Brent E. Gale	Director	February 28, 2011
<u>/s/ Patrick J. Goodman</u> Patrick J. Goodman	Director	February 28, 2011
<u>/s/ Natalie L. Hocken</u> Natalie L. Hocken	Director	February 28, 2011
<u>/s/ Mark C. Moench</u> Mark C. Moench	Director	February 28, 2011
<u>/s/ R. Patrick Reiten</u> R. Patrick Reiten	Director	February 28, 2011
<u>/s/ A. Richard Walje</u> A. Richard Walje	Director	February 28, 2011

EXHIBIT INDEX

Exhibit No. Description

- 3.1* Third Restated Articles of Incorporation of PacifiCorp (Exhibit (3)a, Annual Report on Form 10-K for the year ended December 31, 1996, filed March 21, 1997, File No. 1-5152).
- 3.2* Bylaws of PacifiCorp, as amended May 23, 2005 (Exhibit 3.2, on Annual Report on Form 10-K for the year ended March 31, 2006, filed May 30, 2006, File No. 1-5152).
- 4.1* Mortgage and Deed of Trust dated as of January 9, 1989, between PacifiCorp and The Bank of New York Mellon Trust Company, N.A., Trustee, Ex. 4-E, Form 8-B, File No. 1-5152, as supplemented and modified by 23 Supplemental Indentures as follows:

Exhibit No.	File Type	File Date	File Number
(4)(b)	SE	November 2, 1989	33-31861
(4)(a)	8-K	January 9, 1990	1-5152
4(a)	8-K	September 11, 1991	1-5152
4(a)	8-K	January 7, 1992	1-5152
4(a)	10-Q	Quarter ended March 31, 1992	1-5152
4(a)	10-Q	Quarter ended September 30, 1992	1-5152
4(a)	8-K	April 1, 1993	1-5152
4(a)	10-Q	Quarter ended September 30, 1993	1-5152
(4)b	10-Q	Quarter ended June 30, 1994	1-5152
(4)b	10-K	Year ended December 31, 1994	1-5152
(4)b	10-K	Year ended December 31, 1995	1-5152
(4)b	10-K	Year ended December 31, 1996	1-5152
4(b)	10-K	Year ended December 31, 1998	1-5152
99(a)	8-K	November 21, 2001	1-5152
4.1	10-Q	Quarter ended June 30, 2003	1-5152
99	8-K	September 8, 2003	1-5152
4	8-K	August 24, 2004	1-5152
4	8-K	June 13, 2005	1-5152
4.2	8-K	August 14, 2006	1-5152
4	8-K	March 14, 2007	1-5152
4.1	8-K	October 3, 2007	1-5152
4.1	8-K	July 17, 2008	1-5152
4.1	8-K	January 8, 2009	1-5152

- 4.2* Third Restated Articles of Incorporation and Bylaws. See 3.1 and 3.2 above.

In reliance upon item 601(4)(iii) of Regulation S-K, various instruments defining the rights of holders of long-term debt of the Registrant and its subsidiaries are not being filed because the total amount authorized under each such instrument does not exceed 10% of the total assets of the Registrant and its subsidiaries on a consolidated basis. The Registrant hereby agrees to furnish a copy of any such instrument to the Commission upon request.

- 10.1† Summary of Key Terms of Named Executive Officer and Employee Director Compensation
- 10.2*† PacifiCorp Executive Voluntary Deferred Compensation Plan (Exhibit 10.3, Annual Report on Form 10-K, for the year ended December 31, 2007, filed February 29, 2008, File No. 1-5152).
- 10.3*† Supplemental Executive Retirement Plan (Exhibit 10.7, Annual Report on Form 10-K, for the year ended March 31, 2005, filed May 27, 2005, File No. 1-5152).

- 10.4*† Amendment No. 10 to PacifiCorp Supplemental Executive Retirement Plan dated June 2, 2006 (Exhibit 10.5, Quarterly Report on Form 10-Q, filed August 7, 2006, File No. 1-5152).
- 10.5*† Amendment No. 11 to PacifiCorp Supplemental Executive Retirement Plan dated June 2, 2006 (Exhibit 10.6, Quarterly Report on Form 10-Q, filed August 7, 2006, File No. 1-5152).
- 10.6* \$700,000,000 Credit Agreement dated as of October 23, 2007 among PacifiCorp, The Banks listed on the signatures pages thereto, The Royal Bank of Scotland plc, as Syndication Agent, and Union Bank, N.A. (formerly known as Union Bank of California, N.A.), as Administrative Agent. (Exhibit 99, Quarterly Report on Form 10-Q, filed November 2, 2007, File No. 1-5152).
- 10.7* \$800,000,000 Amended and Restated Credit Agreement dated as of July 6, 2006 among PacifiCorp, The Banks listed on the signatures pages thereto, JPMorgan Chase Bank, N.A., as Administrative Agent and Issuing Bank, and The Royal Bank of Scotland plc, as Syndication Agent. (Exhibit 99, Quarterly Report on Form 10-Q, filed August 4, 2006, File No. 1-5152).
- 10.8* First Amendment dated as of April 15, 2009, amends that certain Credit Agreement, dated as of October 23, 2007, among PacifiCorp, the banks listed on the signatures pages thereto, the Royal Bank of Scotland plc, as Syndication Agent and Union Bank, N.A., (formerly known as Union Bank of California, N.A.), as Administrative Agent. (Exhibit 10.1, Quarterly Report on Form 10-Q, filed May 8, 2009, File No. 1-5152).
- 10.9* First Amendment dated as of April 15, 2009, amends that certain Amended and Restated Credit Agreement, dated as of July 6, 2006, among PacifiCorp, the banks listed on the signature pages thereto, JPMorgan Chase Bank, N.A. as Administrative Agent and Issuing Bank, and the Royal Bank of Scotland plc, as Syndication Agent. (Exhibit 10.2, Quarterly Report on Form 10-Q, filed May 8, 2009, File No. 1-5152).
- 10.10*† Amendment No. 1 to the PacifiCorp Executive Voluntary Deferred Compensation Plan dated October 28, 2008.
- 12.1 Statements of Computation of Ratio of Earnings to Fixed Charges.
- 12.2 Statements of Computation of Ratio of Earnings to Combined Fixed Charges and Preference Dividends.
- 14.1* Code of Ethics (Exhibit 14.1, Transition Report on Form 10-K for the nine-month period ended December 31, 2006, filed March 2, 2007, File No. 1-5152).
- 23.1 Consent of Deloitte & Touche LLP.
- 31.1 Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
- 31.2 Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
- 32.1 Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
- 32.2 Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

*Incorporated herein by reference.

†Management contract or compensatory plan.

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SUMMARY OF KEY TERMS OF COMPENSATION ARRANGEMENTS WITH PACIFICORP'S NAMED EXECUTIVE OFFICERS AND DIRECTORS

PacifiCorp's named executive officers (other than its Chairman and Chief Executive Officer, Greg Abel) and its other employee directors each receive an annual salary and participate in health insurance and other benefit plans on the same basis as other employees, as well as certain other compensation and benefit plans described in PacifiCorp's Annual Report on Form 10-K. Mr. Abel is employed by PacifiCorp's parent company, MidAmerican Energy Holdings Company ("MEHC") and is not directly compensated by PacifiCorp. PacifiCorp reimburses MEHC for the cost of Mr. Abel's time spent on PacifiCorp matters, including compensation paid to him by MEHC, pursuant to an intercompany administrative services agreement among MEHC and its subsidiaries.

The named executive officers and directors are also eligible to receive a cash incentive award under PacifiCorp's Annual Incentive Plan ("AIP"). The AIP provides for a discretionary annual cash award that is determined on a subjective basis and paid in December. In addition to the AIP, the named executive officers are eligible to receive discretionary cash performance awards periodically during the year to reward the accomplishment of significant non-recurring tasks or projects. The named executive officers and directors are participants in MEHC's Long-Term Incentive Partnership Plan ("LTIP"). A copy of the LTIP is attached as Exhibit 10.11 to the MEHC Annual Report on Form 10-K for the year ended December 31, 2010 and incorporated by reference herein.

Base salary for named executive officers and employee directors for PacifiCorp's fiscal year ending December 31, 2011 (excluding Mr. Abel) is shown in the following table:

<u>Name and Title</u>	<u>Base Salary</u>
Douglas K. Stuver Senior Vice President and Chief Financial Officer	\$ 239,269
A. Richard Walje President, Rocky Mountain Power	368,000
R. Patrick Reiten President, Pacific Power	290,000
Micheal G. Dunn President, PacifiCorp Energy	275,000
Brent E. Gale Director	292,750
Natalie L. Hocken Director	194,164
Mark C. Moench Director	222,525

Messrs. Walje, Reiten, Dunn, Gale and Moench and Ms. Hocken are directors of PacifiCorp, but do not receive additional compensation for their service as directors other than what they receive as employees of PacifiCorp. Messrs. Abel, Anderson and Goodman are employees of MEHC, but do not receive additional compensation for their service as directors other than what they receive as employees of MEHC.

PACIFICORP
STATEMENTS OF COMPUTATION OF RATIO
OF EARNINGS TO FIXED CHARGES
(DOLLARS IN MILLIONS)

	Years Ended December 31,				Nine-Month Period Ended December 31, 2006
	2010	2009	2008	2007	
Earnings Available for Fixed Charges:					
Income from continuing operations					
before income tax expense	\$ 777	\$ 784	\$ 703	\$ 665	\$ 253
Add:					
Fixed charges	392	398	349	322	221
Deduct:					
Net income attributable to noncontrolling interest in subsidiary that has not incurred fixed charges	—	(8)	(7)	(6)	(6)
Total earnings available for fixed charges	<u>\$ 1,169</u>	<u>\$ 1,174</u>	<u>\$ 1,045</u>	<u>\$ 981</u>	<u>\$ 468</u>
Fixed Charges:					
Interest expense	\$ 387	\$ 394	\$ 343	\$ 314	\$ 215
Estimated interest portion of rentals charged to expense	5	4	6	8	6
Total fixed charges	<u>\$ 392</u>	<u>\$ 398</u>	<u>\$ 349</u>	<u>\$ 322</u>	<u>\$ 221</u>
Ratio of Earnings to Fixed Charges	<u>3.0 x</u>	<u>2.9 x</u>	<u>3.0 x</u>	<u>3.0 x</u>	<u>2.1 x</u>

PACIFICORP
 STATEMENTS OF COMPUTATION OF RATIO
 OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS
 (DOLLARS IN MILLIONS)

	Years Ended December 31,				Nine-Month Period Ended December 31, 2006
	2010	2009	2008	2007	
Earnings Available for Fixed Charges:					
Income from continuing operations before income tax expense	\$ 777	\$ 784	\$ 703	\$ 665	\$ 253
Add:					
Fixed charges	392	398	349	322	221
Deduct:					
Net income attributable to noncontrolling interest in subsidiary that has not incurred fixed charges	—	(8)	(7)	(6)	(6)
Total earnings available for fixed charges	<u>\$ 1,169</u>	<u>\$ 1,174</u>	<u>\$ 1,045</u>	<u>\$ 981</u>	<u>\$ 468</u>
Fixed Charges and Preferred Stock					
Dividends:					
Interest expense	\$ 387	\$ 394	\$ 343	\$ 314	\$ 215
Estimated interest portion of rentals charged to expense	5	4	6	8	6
Total fixed charges	<u>392</u>	<u>398</u>	<u>349</u>	<u>322</u>	<u>221</u>
Preferred stock dividends	<u>3</u>	<u>3</u>	<u>3</u>	<u>3</u>	<u>2</u>
Total fixed charges and preferred stock dividends	<u>\$ 395</u>	<u>\$ 401</u>	<u>\$ 352</u>	<u>\$ 325</u>	<u>\$ 223</u>
Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends	<u>3.0 x</u>	<u>2.9 x</u>	<u>3.0 x</u>	<u>3.0 x</u>	<u>2.1 x</u>

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CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-170954 on Form S-3ASR of our report dated February 28, 2011, relating to the consolidated financial statements of PacifiCorp and subsidiaries appearing in this Annual Report on Form 10-K of PacifiCorp for the year ended December 31, 2010.

/s/Deloitte & Touche LLP
Deloitte & Touche LLP

Portland, Oregon
February 28, 2011

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Gregory E. Abel, certify that:

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

Date: February 28, 2011

/s/ Gregory E. Abel

Gregory E. Abel

Chairman of the Board of Directors and Chief Executive Officer
(principal executive officer)

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Douglas K. Stuver, certify that:

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

Date: February 28, 2011

/s/ Douglas K. Stuver

Douglas K. Stuver

Senior Vice President and Chief Financial Officer

(principal financial officer)

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Gregory E. Abel, Chairman of the Board of Directors and Chief Executive Officer of PacifiCorp, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

- (1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2010 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and
- (2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: February 28, 2011

/s/ Gregory E. Abel

Gregory E. Abel

Chairman of the Board of Directors and Chief Executive Officer
(principal executive officer)

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Douglas K. Stuver, Senior Vice President and Chief Financial Officer of PacifiCorp, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

- (1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2010 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o (d)); and
- (2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: February 28, 2011

/s/ Douglas K. Stuver

Douglas K. Stuver
Senior Vice President and Chief Financial Officer
(principal financial officer)