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

FORM 10-K

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

For the fiscal year ended December 31, 2009

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.
001-14881	**MIDAMERICAN ENERGY HOLDINGS COMPANY** **(An Iowa Corporation)** **666 Grand Avenue, Suite 500** **Des Moines, Iowa 50309-2580** **515-242-4300**	**94-2213782**

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☐ 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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes ☐ 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 of the shares of common equity of MidAmerican Energy Holdings Company are privately held by a limited group of investors. As of January 31, 2010, 74,859,001 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 "may," "could," "project," "believe," "anticipate," "expect," "estimate," "continue," "intend," "potential," "plan," "forecast" and similar terms. These statements are based upon the Company's current intentions, assumptions, expectations and beliefs and are subject to risks, uncertainties and other important factors. Many of these factors are outside the Company's control and could cause actual results to differ materially from those expressed or implied by the Company's forward-looking statements. These factors include, among others:

- general economic, political and business conditions in the jurisdictions in which the Company's facilities operate;
- changes in federal, state and local governmental, legislative or regulatory requirements, including those pertaining to income taxes, affecting the Company or the electric or gas utility, pipeline or power generation industries;
- changes in, and compliance with, environmental laws, regulations, decisions and policies that could, among other items, increase operating and capital costs, reduce plant output or delay plant construction;
- 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 supply of electricity and gas or the Company's ability to obtain long-term contracts with customers and suppliers;
- a high degree of variance between actual and forecasted load and prices that could impact the hedging strategy and costs to balance electricity and load supply;
- 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 generation capacity and energy costs;
- the financial condition and creditworthiness of the Company'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 MidAmerican Energy Holdings Company's ("MEHC") and its subsidiaries' credit facilities;
- changes in MEHC's and its subsidiaries' credit ratings;
- performance of the Company's generating facilities, including unscheduled outages or repairs;
- risks relating to nuclear generation;
- the impact of derivative contracts used to mitigate or manage volume, price and interest rate risk, including increased collateral requirements, and changes in the commodity prices, interest rates and other conditions that affect the fair value of derivative contracts;
- increases in employee healthcare costs and the potential impact of federal healthcare reform legislation;
- the impact of investment performance and changes in interest rates, legislation, healthcare cost trends, mortality and morbidity on pension and other postretirement benefits expense and funding requirements;
- changes in the residential real estate brokerage and mortgage industries that could affect brokerage transaction levels;
- 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 pronouncements or changes in current accounting estimates and assumptions on consolidated financial results;
- the Company's ability to successfully integrate future acquired operations into its business;
- other risks or unforeseen events, including litigation, wars, the effects of terrorism, embargoes and other catastrophic events; and
- other business or investment considerations that may be disclosed from time to time in MEHC'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 the Company are described in Item 1A and other discussions contained in this Form 10-K. The Company 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

MidAmerican Energy Holdings Company ("MEHC") is a holding company that owns subsidiaries principally engaged in energy businesses (collectively with its subsidiaries, the "Company"). MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway"). The balance of MEHC's common stock is owned by Mr. Walter Scott, Jr. (along with family members and related entities), a member of MEHC's Board of Directors, and Mr. Gregory E. Abel, a member of MEHC's Board of Directors and MEHC's President and Chief Executive Officer. As of January 31, 2010, Berkshire Hathaway, Mr. Scott (along with family members and related entities) and Mr. Abel owned 89.5%, 9.7% and 0.8%, respectively, of MEHC's voting common stock.

On March 1, 2006, MEHC and Berkshire Hathaway entered into an Equity Commitment Agreement (the "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 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. 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. The Berkshire Equity Commitment expires on February 28, 2011.

The Company's operations are organized and managed as eight distinct platforms: PacifiCorp, MidAmerican Funding, LLC ("MidAmerican Funding") (which primarily includes MidAmerican Energy Company ("MidAmerican Energy")), Northern Natural Gas Company ("Northern Natural Gas"), Kern River Gas Transmission Company ("Kern River"), CE Electric UK Funding Company ("CE Electric UK") (which primarily includes Northern Electric Distribution Limited ("Northern Electric") and Yorkshire Electricity Distribution plc ("Yorkshire Electricity")), CalEnergy Generation-Foreign (which owns a majority interest in the Casecnan project in the Philippines), CalEnergy Generation-Domestic (which owns interests in independent power projects in the United States), and HomeServices of America, Inc. (collectively with its subsidiaries, "HomeServices"). Through these platforms, MEHC owns and operates an electric utility company in the Western United States, an electric and natural gas utility company in the Midwestern United States, two interstate natural gas pipeline companies in the United States, two electricity distribution companies in Great Britain, a diversified portfolio of independent power projects and the second-largest residential real estate brokerage firm in the United States.

MEHC's energy subsidiaries generate, transmit, store, distribute and supply energy. Approximately 97% of the Company's operating income in 2009 was generated from rate-regulated businesses. As of December 31, 2009, MEHC's electric and natural gas utility subsidiaries served 6.2 million electricity customers and end-users and 0.7 million natural gas customers. MEHC's natural gas pipeline subsidiaries operate interstate natural gas transmission systems that transported approximately 8% of the total natural gas consumed in the United States in 2009. These pipeline subsidiaries have approximately 17,000 miles of pipeline and a design capacity of more than 7.0 billion cubic feet ("Bcf") of natural gas per day. As of December 31, 2009, the Company had interests in approximately 18,000 net owned megawatts ("MW") of power generation facilities in operation, including approximately 17,000 net owned MW in facilities that are part of the regulated asset base of its electric utility businesses and approximately 1,000 net owned MW in non-utility power generation facilities.

Refer to Note 22 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional segment information regarding MEHC's platforms.

MEHC's principal executive offices are located at 666 Grand Avenue, Suite 500, Des Moines, Iowa 50309-2580 and its telephone number is (515) 242-4300. MEHC was initially incorporated in 1971 under the laws of the state of Delaware and reincorporated in 1999 in Iowa, which resulted in a change of its name from CalEnergy Company, Inc. to MidAmerican Energy Holdings Company.

PacifiCorp

General

On March 21, 2006, a wholly owned subsidiary of MEHC acquired 100% of the common stock of PacifiCorp from a wholly owned subsidiary of Scottish Power plc for a cash purchase price of $5.12 billion, including direct transaction costs. In connection with MEHC's acquisition of PacifiCorp, PacifiCorp and MEHC agreed to certain material financial regulatory commitments as discussed in Note 16 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

PacifiCorp is a United States regulated electric utility company headquartered in Oregon that serves 1.7 million retail electric customers in portions of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp is principally engaged in the business of generating, transmitting, distributing and selling electricity. 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. No single segment of the economy dominates the service territory, which helps mitigate PacifiCorp's exposure to economic fluctuations. In addition to retail sales, PacifiCorp sells electric energy to other utilities, municipalities and marketers on a wholesale basis.

PacifiCorp's regulated electric operations are conducted under numerous franchise agreements, certificates, permits and licenses obtained from federal, state and local authorities. The average term of these franchise 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.

Regulated Electric Operations

<u>Customers</u>

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

	2009	2008	2007
Utah	42%	42%	42%
Oregon	25	26	26
Wyoming	17	17	16
Washington	8	7	8
Idaho	6	6	6
California	2	2	2
	100%	100%	100%

The percentages of 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:

	2009	2008	2007
Residential	24%	24%	24%
Commercial	25	24	24
Industrial	31	32	31
Other	1	1	1
Total retail	81	81	80
Wholesale	19	19	20
Total retail and wholesale	100%	100%	100%
Total GWh sold:			
Retail	52,710	54,362	53,390
Wholesale	12,349	12,345	13,724
Total retail and wholesale	65,059	66,707	67,114
Total average retail customers (in millions)	1.7	1.7	1.7

In addition to the variations in weather from year to year, fluctuations in economic conditions within the 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 in 2009, resulting in lower retail demands than in 2008.

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 the year ended December 31, 2009, PacifiCorp's peak demand was 9,420 MW in the summer and 9,336 MW in the winter.

Power and Fuel Supply

PacifiCorp has ownership interests in a diverse portfolio of power generating facilities. The following table presents certain information concerning PacifiCorp's owned power generating facilities as of December 31, 2009:

	Location	Energy Source	Installed	Facility Net Capacity (MW)[(1)]	Net MW Owned[(1)]
COAL:					
Jim Bridger	Rock Springs, WY	Coal	1974-1979	2,117	1,411
Hunter Nos. 1, 2 and 3	Castle Dale, UT	Coal	1978-1983	1,320	1,122
Huntington	Huntington, UT	Coal	1974-1977	895	895
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
				9,478	6,116
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 Peakers	Salt Lake City, UT	Natural gas	2002	122	122
Little Mountain	Ogden, UT	Natural gas	1971	14	14
				2,469	2,232
HYDROELECTRIC:					
Lewis River System	WA	Hydroelectric	1931-1958	578	578
North Umpqua River System	OR	Hydroelectric	1950-1956	200	200
Klamath River System	CA, OR	Hydroelectric	1903-1962	170	170
Bear River System	ID, UT	Hydroelectric	1908-1984	105	105
Rogue River System	OR	Hydroelectric	1912-1957	52	52
Minor hydroelectric facilities	Various	Hydroelectric	1895-1986	53	53
				1,158	1,158
WIND:					
Marengo	Dayton, WA	Wind	2007-2008	210	210
Glenrock	Glenrock, WY	Wind	2008-2009	138	138
Seven Mile Hill	Medicine Bow, WY	Wind	2008	119	119
Leaning Juniper	Arlington, OR	Wind	2006	101	101
High Plains	McFadden, WY	Wind	2009	99	99
Rolling Hills	Glenrock, WY	Wind	2009	99	99
Goodnoe Hills	Goldendale, WA	Wind	2008	94	94
Foote Creek	Arlington, WY	Wind	1999	41	33
McFadden Ridge	McFadden, WY	Wind	2009	28	28
				929	921
OTHER:					
Blundell	Milford, UT	Geothermal	1984, 2007	34	34
Camas Co-Gen	Camas, WA	Black liquor	1996	22	22
				56	56
Total Available Generating Capacity				14,090	10,483

(1) Facility Net Capacity (MW) represents (except for wind-powered generation 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 MW Owned indicates PacifiCorp's ownership of Facility Net Capacity.

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

	2009	2008	2007
Coal	63%	65%	64%
Natural gas	12	12	11
Hydroelectric	5	5	5
Other[(1)]	4	2	1
Total energy generated	84	84	81
Energy purchased - short-term contracts and other	10	11	14
Energy purchased - long-term contracts	6	5	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 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.

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 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 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 owns coal mines that support its coal-fired generating facilities. These mines supplied 31% of PacifiCorp's total coal requirements during each of the years ended December 31, 2009, 2008 and 2007. The remaining coal requirements are acquired through long- and short-term third-party contracts. PacifiCorp's mines are located adjacent to many 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, 2009, based on PacifiCorp's most recent engineering studies, were as follows (in millions):

Location	Plant Served	Mining Method	Recoverable Tons	
Craig, CO	Craig	Surface	46	(1)
Huntington & Castle Dale, UT	Huntington and Hunter	Underground	30	(2)
Rock Springs, WY	Jim Bridger	Surface	83	(3)
Rock Springs, WY	Jim Bridger	Underground	50	(3)
			209	

(1) 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.

(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 Bridger Coal Company, 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 represents only PacifiCorp's two-thirds interest in the coal reserves.

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 technologies for controlling sulfur dioxide ("SO_2") 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 remaining generating facilities over their currently expected useful lives.

During the year ended December 31, 2009, PacifiCorp-owned coal-fired generating facilities held sufficient SO_2 emission allowances to comply with the United States Environmental Protection Agency ("EPA") Title IV requirements.

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, transmission support and standby purposes. These sources are presently in adequate supply and available to meet PacifiCorp's needs.

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 River System, refer to Note 16 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

PacifiCorp is pursuing 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 generation facilities and wholesale transactions. PacifiCorp's wind-powered generating facilities are eligible for federal renewable electricity production tax credits ("PTCs") for 10 years from the date that the facilities were placed in-service. In February 2009, legislation was passed extending the date by which such facilities must be placed in service to be eligible for PTCs to December 31, 2012.

In addition to its portfolio of generating facilities, PacifiCorp purchases and sells electricity in the wholesale markets to serve its retail load and to enhance the efficient use of its generating capacity over the long-term. PacifiCorp purchases electricity in the wholesale markets when it is more economical than generating it at its own facilities. PacifiCorp sells into the wholesale market available electricity arising from imbalances between generation and retail load obligations, subject to pricing and transmission constraints. Many of PacifiCorp's purchased electricity contracts have fixed-price components, which provide some protection against price volatility.

Transmission and Distribution

PacifiCorp operates two balancing authority areas in its service territory, a geographic area with electric 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 electric 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 Electric Coordinating Council ("WECC"). 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. The electric transmission system of PacifiCorp included 15,900 miles of transmission lines and 900 substations as of December 31, 2009.

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, Oregon and the desert Southwest. 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 resource areas, including renewable resources; and (e) improve the flow of electricity throughout PacifiCorp's six-state service area and the

Western United States. Proposed transmission line segments are re-evaluated to ensure maximum benefits and timing before committing to move forward with permitting and construction. The first major transmission segments associated with this plan are expected to be placed in service during 2010, with other segments placed in service through 2019, depending on siting, permitting and construction schedules.

Future Generation

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 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. In May 2009, PacifiCorp filed its 2008 IRP with each of its state commissions. During 2009, PacifiCorp received orders from Washington and Idaho acknowledging that the IRP met their applicable standards and guidelines. In February 2010, the OPUC issued an order acknowledging the 2008 IRP. Acknowledgement of the 2008 IRP by the UPSC is pending.

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. Subject to random prudence reviews, state regulations allow for contemporaneous recovery of costs incurred for the DSM programs through state-specific energy efficiency service charges paid by retail electric customers. In addition to these DSM programs, PacifiCorp has load curtailment contracts with a number of large industrial customers that deliver up to 342 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. In 2009, $106 million was expended on the DSM programs in PacifiCorp's six-state service area, resulting in an estimated 457,000 megawatt hours ("MWh") of first-year energy savings and 441 MW of peak load management. Total demand-side load available for control in 2009, including both load management from the large industrial curtailment contracts and DSM programs, was 783 MW.

MidAmerican Energy

General

MidAmerican Energy, an indirect wholly owned subsidiary of MEHC, is a United States regulated electric and gas utility company headquartered in Iowa that serves 0.7 million regulated retail electric customers in portions of Iowa, Illinois and South Dakota and 0.7 million regulated retail and transportation natural gas customers in portions of Iowa, South Dakota, Illinois and Nebraska. MidAmerican Energy is principally engaged in the business of generating, transmitting, distributing and selling electricity and in distributing, selling and transporting natural gas. MidAmerican Energy has a diverse customer base consisting of residential, agricultural and a variety of commercial and industrial customer groups. Some of the larger industrial groups served by MidAmerican Energy include the processing and sales of food products; the manufacturing, processing and fabrication of primary metals; farm and other non-electrical machinery; real estate; and cement and gypsum products. In addition to retail sales and natural gas transportation, MidAmerican Energy sells electric energy to markets operated by regional transmission organizations ("RTOs") and electric energy and natural gas to other utilities, municipalities and marketers on a wholesale basis.

MidAmerican Energy's regulated electric and gas operations are conducted under numerous franchise agreements, certificates, permits and licenses obtained from federal, state and local authorities. The franchise agreements, with various expiration dates, are typically for 25-year terms. MidAmerican Energy 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 MidAmerican Energy an opportunity to recover its costs of providing services and to earn a reasonable return on its investment.

MidAmerican Energy has nonregulated business activities that consist of competitive electric and natural gas retail sales and gas income-sharing arrangements. Nonregulated electric activities predominantly include sales to retail customers in Illinois and other states that allow customers to choose their energy supplier. For its nonregulated gas activities, MidAmerican Energy purchases gas from producers and third party marketers and sells it directly to commercial and industrial end-users, as well as wholesalers, primarily in Iowa and Illinois. In addition, MidAmerican Energy manages gas supplies for a number of smaller commercial end-users, which includes the sale of gas to these customers to meet their supply requirements.

The percentages of MidAmerican Energy's operating revenue derived from the following business activities during the years ended December 31 were as follows:

	2009	2008	2007
Regulated electric	47%	43%	45%
Regulated gas	23	29	28
Nonregulated and other	30	28	27
	100%	100%	100%

Regulated Electric Operations

Customers

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

	2009	2008	2007
Iowa	90%	90%	90%
Illinois	9	9	9
South Dakota	1	1	1
	100%	100%	100%

The percentages of electricity sold to retail and wholesale customers by class of customer, total GWh sold and the average number of retail customers for the years ended December 31 were as follows:

	2009	2008	2007
Residential	17%	17%	18%
Commercial	12	12	12
Industrial	26	25	27
Other	5	4	5
Total retail	60	58	62
Wholesale	40	42	38
Total retail and wholesale	100%	100%	100%
Total GWh sold:			
Retail	20,185	20,928	20,976
Wholesale	13,424	15,133	12,638
Total retail and wholesale	33,609	36,061	33,614
Total average retail customers (in millions)	0.7	0.7	0.7

In addition to the variations in weather from year to year, fluctuations in economic conditions within the service territory and elsewhere can impact customer usage, particularly for industrial and wholesale customers. Beginning in the third quarter of 2008, industrial customer usage levels began to decline due to the effects of the economic conditions in the United States. The declining usage trend continued in 2009, resulting in lower retail demand than in 2008.

There are seasonal variations in MidAmerican Energy's electric business that are principally related to the use of electricity for air conditioning and the related effects of weather. Typically, 35-40% of MidAmerican Energy's regulated electric revenue is reported in the months of June, July, August and September.

The annual hourly peak demand on MidAmerican Energy's electric system usually occurs as a result of air conditioning use during the cooling season. Peak demand represents the highest demand on a given day and at a given hour. On June 22, 2009, retail customer usage of electricity caused a record hourly peak demand of 4,299 MW on MidAmerican Energy's electric system, which is 59 MW greater than the previous peak demand of 4,240 MW set August 13, 2007.

Power and Fuel Supply

MidAmerican Energy has ownership interests in a diverse portfolio of power generating facilities. The following table presents certain information concerning MidAmerican Energy's owned power generating facilities as of December 31, 2009:

	Location	Energy Source	Installed	Facility Net Capacity (MW)[1]	Net MW Owned[1]
COAL:					
Walter Scott, Jr. Nos. 1, 2, 3 and 4	Council Bluffs, IA	Coal	1954-2007	1,623	1,156
George Neal Nos. 1, 2 and 3	Sergeant Bluff, IA	Coal	1964-1975	945	801
Louisa	Muscatine, IA	Coal	1983	745	656
Ottumwa	Ottumwa, IA	Coal	1981	710	369
George Neal No. 4	Salix, IA	Coal	1979	644	261
Riverside Nos. 3 and 5	Bettendorf, IA	Coal	1925-1961	135	135
				4,802	3,378
NATURAL GAS:					
Greater Des Moines	Pleasant Hill, IA	Natural gas	2003-2004	498	498
Electrifarm	Waterloo, IA	Natural gas/oil	1975-1978	199	199
Pleasant Hill	Pleasant Hill, IA	Natural gas/oil	1990-1994	162	162
Sycamore	Johnston, IA	Natural gas/oil	1974	149	149
River Hills	Des Moines, IA	Natural gas	1966-1967	119	119
Coralville	Coralville, IA	Natural gas	1970	64	64
Moline	Moline, IL	Natural gas	1970	64	64
Parr	Charles City, IA	Natural gas	1969	32	32
28 portable power modules	Various	Oil	2000	56	56
				1,343	1,343
WIND:					
Pomeroy	Pomeroy, IA	Wind	2007-2008	256	256
Century	Blairsburg, IA	Wind	2005-2008	200	200
Intrepid	Schaller, IA	Wind	2004-2005	176	176
Adair	Adair, IA	Wind	2008	175	175
Walnut	Walnut, IA	Wind	2008	153	153
Carroll	Carroll, IA	Wind	2008	150	150
Victory	Westside, IA	Wind	2006	99	99
Charles City	Charles City, IA	Wind	2008	75	75
				1,284	1,284
NUCLEAR:					
Quad Cities Nos. 1 and 2	Cordova, IL	Uranium	1972	1,740	435
OTHER:					
Moline Nos. 1-4	Moline, IL	Mississippi River	1941	3	3
Total Available Generating Capacity				9,172	6,443

(1) Facility Net Capacity (MW) represents (except for wind-powered generation facilities, which are nominal ratings) total plant accredited net generating capacity from the summer of 2009 based on MidAmerican Energy's accreditation approved by the Mid-Continent Area Power Pool ("MAPP"). The 2009 summer accreditation of the wind-powered generation facilities in service at that time totaled 297 MW and is considerably less than the nominal ratings due to the varying nature of wind. Net MW Owned indicates MidAmerican Energy's ownership of Facility Net Capacity.

The following table shows the percentage of MidAmerican Energy's total energy supplied by energy source for the years ended December 31:

	2009	2008	2007
Coal	60%	59%	56%
Nuclear	11	10	10
Natural gas	1	3	3
Other[(1)]	10	6	5
Total energy generated	82	78	74
Energy purchased - short-term contracts and other	11	14	19
Energy purchased - long-term contracts	7	8	7
	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.

The percentage of MidAmerican Energy'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, MidAmerican Energy may place more reliance on other energy sources. For example, when wind conditions are favorable, MidAmerican Energy can generate more electricity using its low cost wind-powered generating facilities. When wind resources are less favorable, MidAmerican Energy must increase its reliance on more expensive generation or purchased electricity. MidAmerican Energy manages certain risks relating to its supply of electricity and fuel requirements by entering into various contracts, which may be 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.

All of the coal-fired generating facilities operated by MidAmerican Energy are fueled by low-sulfur, western coal from the Powder River Basin in northeast Wyoming. MidAmerican Energy's coal supply portfolio includes multiple suppliers and mines under short-term and multi-year agreements of varying terms and quantities. MidAmerican Energy's coal supply portfolio has a substantial majority of its expected 2010-2011 requirements under fixed-price contracts. MidAmerican Energy regularly monitors the western coal market for opportunities to enhance its coal supply portfolio. During the year ended December 31, 2009, MidAmerican Energy-owned generating facilities held sufficient allowances for SO_2 and nitrogen oxide ("NO_x") emissions to comply with the EPA Title IV and Clean Air Interstate Rule requirements.

MidAmerican Energy has a long-haul coal transportation agreement with Union Pacific Railroad Company ("Union Pacific"). Under this agreement, Union Pacific delivers coal directly to MidAmerican Energy's George Neal and Walter Scott, Jr. Energy Centers and to an interchange point with Canadian Pacific Railway for short-haul delivery to the Louisa and Riverside Energy Centers. MidAmerican Energy has the ability to use BNSF Railway Company, an affiliate company, for delivery of a small amount of coal to the Walter Scott, Jr., Louisa and Riverside Energy Centers should the need arise.

MidAmerican Energy is a 25% joint owner of Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station"), a nuclear power plant. Exelon Generation Company, LLC ("Exelon Generation"), the 75% joint owner and the operator of Quad Cities Station, is a subsidiary of Exelon Corporation. Approximately one-third of the nuclear fuel assemblies in each reactor core at the Quad Cities Station is replaced every 24 months. MidAmerican Energy has been advised by Exelon Generation that the following requirements for the Quad Cities Station can be met under existing supplies or commitments: uranium requirements through 2012 and partial requirements through 2020; uranium conversion requirements through 2015 and partial requirements through 2020; enrichment requirements through 2012 and partial requirements through 2028; and fuel fabrication requirements through 2019. MidAmerican Energy has been advised by Exelon Generation that it does not anticipate it will have difficulty in contracting for uranium, uranium conversion, enrichment or fabrication of nuclear fuel needed to operate Quad Cities Station during these time periods.

MidAmerican Energy uses natural gas and oil as fuel for intermediate and peak demand electric generation, igniter fuel, transmission support and standby purposes. These sources are presently in adequate supply and available to meet MidAmerican Energy's needs.

MidAmerican Energy has the largest owned wind-powered generation fleet of any United States electric utility and believes wind-powered generation offers a viable, economical and environmentally prudent means of supplying electricity. Additionally, MidAmerican Energy has regulatory approval to construct up to 1,001 MW (nominal ratings) of additional wind-powered generation in Iowa through 2012, the last 251 MW of which is subject to confirmation from the Iowa Utilities Board ("IUB"). MidAmerican Energy has further committed that not greater than 500 MW will be placed in service during 2012. Wind projects under this agreement are authorized to earn a 12.2% return on equity in any future Iowa rate proceeding. Renewable resources have low to no emissions, require little or no fossil fuel and are complemented by MidAmerican Energy's other generating facilities and wholesale transactions. MidAmerican Energy's wind-powered generating facilities are eligible for federal renewable electricity PTCs for 10 years from the date the facilities were placed in-service. In February 2009, legislation was passed extending the date by which such facilities must be placed in service to be eligible for PTCs to December 31, 2012.

In addition to its portfolio of generating facilities, MidAmerican Energy purchases and sells electricity and ancillary services in the wholesale markets to serve its retail load and to enhance the efficient use of its generating capacity over the long-term. MidAmerican Energy purchases electricity in the wholesale markets when it is more economical than generating it at its own facilities. MidAmerican Energy sells into the wholesale market available electricity arising from imbalances between generation and retail load obligations, subject to pricing and transmission constraints.

Transmission and Distribution

Electricity from MidAmerican Energy's generating facilities and purchased electricity is delivered to wholesale markets and its retail customers, via the transmission facilities of MidAmerican Energy and others. MidAmerican Energy determined that participation in an RTO energy and ancillary service market as a transmission-owning member would be superior to continuing as a stand-alone balancing control area and provide MidAmerican Energy with enhanced wholesale marketing opportunities and improved economic dispatch of its generating facilities. Effective September 1, 2009, MidAmerican Energy integrated its facilities with the Midwest Independent Transmission System Operator, Inc. ("MISO") as a transmission-owning member. Accordingly, MidAmerican Energy now operates its transmission assets at the direction of the MISO.

In its role as the operator of its energy, capacity and ancillary service market, the MISO continually balances electric supply and demand in its day-ahead and real-time markets. Primarily through a centralized economic dispatch that optimizes the use of generation resources within the region, the MISO controls the day-to-day operations of the bulk power system for the region served by its members. Additionally, the MISO provides transmission service to MidAmerican Energy and others through its open access transmission tariff.

MidAmerican Energy can enter into wholesale bilateral transactions with a number of parties within the MISO market footprint and can also participate directly in the MISO market. MidAmerican Energy's wholesale transactions can also occur through the Southwest Power Pool, Inc. ("SPP") and PJM Interconnection, L.L.C. RTOs and several other major transmission-owning utilities in the region as a result of transmission interconnections MISO has with such organizations. The electric transmission and distribution systems of MidAmerican Energy included 2,300 miles of transmission lines and 400 substations as of December 31, 2009.

Regulated Natural Gas Operations

MidAmerican Energy is engaged in the procurement, transportation, storage and distribution of natural gas for customers in its service territory. MidAmerican Energy purchases natural gas from various suppliers, transports it from the production areas to MidAmerican Energy's service territory under contracts with interstate natural gas pipelines, stores it in various storage facilities to manage fluctuations in system demand and seasonal pricing, and delivers it to customers through MidAmerican Energy's distribution system. MidAmerican Energy sells natural gas and transportation services to end-use customers and natural gas to other utilities, municipalities and marketers. MidAmerican Energy also transports natural gas through its distribution system for a number of end-use customers who have independently secured their supply of natural gas. During 2009, 46% of the total natural gas delivered through MidAmerican Energy's system for end-use customers was under natural gas transportation service.

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

	2009	2008	2007
Iowa	76%	77%	77%
South Dakota	13	12	12
Illinois	10	10	10
Nebraska	1	1	1
	100%	100%	100%

The percentages of natural gas sold to retail and wholesale customers by class of customer, total decatherms ("Dth") of natural gas sold, total Dth of transportation service and the average number of retail customers for the years ended December 31 were as follows:

	2009	2008	2007
Residential	42%	42%	40%
Commercial(1)	22	21	19
Industrial(1)	4	4	4
Total retail	68	67	63
Wholesale(2)	32	33	37
	100%	100%	100%
Total Dth of natural gas sold (000's)	121,355	132,172	124,391
Total Dth of transportation service (000's)	69,642	68,782	65,876
Total average number of retail customers (in millions)	0.7	0.7	0.7

(1) Commercial and industrial customers are classified primarily based on the nature of their business and natural gas usage. Commercial customers are business customers whose natural gas usage is principally for heating. Industrial customers are business customers whose principal natural gas usage is for their manufacturing processes.

(2) Wholesale generally includes other utilities, municipalities and marketers to whom natural gas is sold at wholesale for eventual resale to end-use customers.

There are seasonal variations in MidAmerican Energy's natural gas business that are principally due to the use of natural gas for heating. Typically, 45-55% of MidAmerican Energy's regulated natural gas revenue is reported in the months of January, February, March and December.

On January 15, 2009, MidAmerican Energy recorded its all-time highest peak-day delivery of 1,147,599 Dth. This peak-day delivery consisted of approximately 75% traditional retail sales service and 25% transportation service of customer-owned gas. As of January 31, 2010, MidAmerican Energy's 2009/2010 winter heating season peak-day delivery of 1,058,757 Dth was reached on January 4, 2010. This peak-day delivery included 71% traditional retail sales service and 29% transportation service.

Fuel Supply and Capacity

MidAmerican Energy is allowed to recover its cost of natural gas from all of its regulated natural gas customers through purchased gas adjustment clauses ("PGA"). Accordingly, as long as MidAmerican Energy is prudent in its procurement practices, MidAmerican Energy's regulated natural gas customers retain the risk associated with the market price of natural gas. MidAmerican Energy uses several strategies designed to reduce volatility of natural gas prices for its natural gas customers while maintaining system reliability, including a geographically diverse supply portfolio from producers and third party marketers, the use of storage gas and peak-shaving facilities, sharing arrangements to share savings and costs with customers and short- and long-term financial and physical gas purchase contracts.

MidAmerican Energy has rights to firm natural gas pipeline capacity to transport natural gas to its service territory through direct interconnects to the pipeline systems of several interstate natural gas pipeline systems, including Northern Natural Gas, an affiliate company.

MidAmerican Energy utilizes leased gas storage to meet peak day requirements and to manage the daily changes in demand due to changes in weather. The storage gas is typically replaced during off-peak months when the demand for natural gas is historically lower than during the heating season. In addition, MidAmerican Energy also utilizes its three liquefied natural gas ("LNG") plants and one propane-air plant to meet peak day demands in the winter. The storage and peak shaving facilities reduce MidAmerican Energy's dependence on natural gas purchases during the volatile winter heating season. MidAmerican Energy can deliver approximately 50% of its design day sales requirements from its storage and peak shaving supply sources.

Natural gas property consists primarily of natural gas mains and services pipelines, meters, and related distribution equipment, including feeder lines to communities served from natural gas pipelines owned by others. The gas distribution facilities of MidAmerican Energy included 22,000 miles of gas mains and service pipelines as of December 31, 2009.

Demand-side Management

MidAmerican Energy has provided a comprehensive set of DSM programs to its Iowa electric and gas customers since 1990, its Illinois electric and gas customers since 2008 and, beginning in 2009, its South Dakota gas customers. 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, MidAmerican Energy 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 residential customers who participate in the air conditioner load control program and nonresidential customers who participate in the nonresidential load management program. Subject to prudence reviews, state regulations allow for contemporaneous recovery of costs incurred for the DSM programs through state-specific energy efficiency service charges paid by all retail electric and gas customers. In 2009, $63 million was expended on the DSM programs resulting in an estimated 240,000 MWh of electric and 474,000 Dth of gas first-year energy savings and an estimated 304 MW of electric and 6,691 Dth/day of gas peak load management.

Interstate Natural Gas Pipeline Companies

Northern Natural Gas

Northern Natural Gas, an indirect wholly owned subsidiary of MEHC, owns one of the largest interstate natural gas pipeline systems in the United States, which reaches from southern Texas to Michigan's Upper Peninsula. Northern Natural Gas' pipeline system, which is interconnected with many interstate and intrastate pipelines in the national grid system, consists of two distinct, but operationally integrated, markets. Its traditional end-use and distribution market area, referred to as the Market Area, includes points in Iowa, Nebraska, Minnesota, Wisconsin, South Dakota, Michigan and Illinois. Its natural gas supply and delivery service area, referred to as the Field Area, includes Kansas, Texas, Oklahoma and New Mexico. Northern Natural Gas primarily transports and stores natural gas for utilities, municipalities, other pipeline companies, gas marketers, industrial and commercial users and other end-users. Northern Natural Gas' pipeline system consists of 15,000 miles of natural gas pipelines, including 6,400 miles of mainline transmission pipelines and 8,600 miles of branch and lateral pipelines, with a Market Area design capacity of 5.5 Bcf per day and a Field Area delivery capacity of 2.0 Bcf per day to the Market Area. Based on a review of relevant 2008 industry data, the Northern Natural Gas system is believed to be the largest single pipeline in the United States as measured by pipeline miles and the eighth-largest as measured by throughput. In 2009, Northern Natural Gas' transportation and storage revenue accounted for 94% of its total operating revenue, of which 85% was generated from reservation charges under firm transportation and storage contracts. About 57% of the charges under the firm transportation and storage contracts were from utilities. Except for quantities of natural gas owned and managed for operational and system balancing purposes, Northern Natural Gas does not own the natural gas that is transported through its system. The sale of natural gas for operational and system balancing purposes accounts for the majority of the remaining 6% of its 2009 operating revenue. Northern Natural Gas' transportation and storage operations are subject to a regulated tariff that is on file with the FERC. The tariff rates are designed to allow Northern Natural Gas an opportunity to recover its costs and generate a regulated return on equity.

Northern Natural Gas' pipeline system provides its customers access to natural gas from key production areas, including the Hugoton, Permian, Anadarko and Rocky Mountain basins in its Field Area and, through interconnections with other pipelines, the Rocky Mountain, Williston and Canadian basins in its Market Area. In each of these areas, Northern Natural Gas has numerous interconnecting receipt and delivery points.

Northern Natural Gas transports natural gas primarily to end-users and local distribution markets in the Market Area. In 2009, 70% of Northern Natural Gas' transportation and storage revenue was generated from Market Area customer transportation contracts. Northern Natural Gas directly serves 76 utilities, including MidAmerican Energy, and in turn, these utilities serve numerous residential, commercial and industrial customers. A majority of Northern Natural Gas' capacity in the Market Area is committed to customers under firm transportation contracts. As of December 31, 2009, 93% of Northern Natural Gas' customers' entitlement in the Market Area is contracted beyond 2010, and 50% is contracted beyond 2015. The weighted average remaining contract term for Northern Natural Gas' Market Area transportation contracts is approximately six years as of December 31, 2009.

Northern Natural Gas' Northern Lights expansion project is concentrated primarily in the Twin Cities area of Minnesota and is expected to serve incremental load due to residential and commercial growth in natural gas demand, gas-fired power plants and ethanol facilities. Northern Natural Gas has commitments to two of its largest customers to meet minimum levels of incremental capacity requests through 2026. The project is designed to deliver volumes needed to meet those commitments. The project is expected to add 650,000 Dth per day of capacity to its Market Area by the end of 2010, of which 610,000 Dth per day has been added as of December 31, 2009. In total, the Northern Lights expansion project is expected to require more than $340 million in capital expenditures through 2010, of which $320 million has been incurred through December 31, 2009.

In the Field Area, customers that contract for firm transportation capacity, or entitlement, consist primarily of marketers, power generators and producers. The majority of this entitlement is contracted on a short-term basis, principally by marketers and producers. Northern Natural Gas expects short-term contracting to continue in the foreseeable future to support Market Area customers' demand requirements. Supplies from the Field Area have historically been less expensive than the supply alternatives available from other sources that bring Canadian supply to Northern Natural Gas' system in the Market Area. However, the revenue received from these contracts is expected to vary in relationship to the spread in natural gas prices between the MidContinent Region and Canada. Additionally, a weaker economy and lower market loads in the upper Midwest markets east of Northern Natural Gas' pipeline system, such as in Chicago and Michigan, create a risk of more Canadian supply being delivered into Northern Natural Gas' Market Area providing competition to Northern Natural Gas' supply from the Field Area. In 2009, 16% of Northern Natural Gas' transportation and storage revenue was generated from Field Area customer transportation contracts.

Northern Natural Gas' storage services are provided through the operation of one underground natural gas storage field in Iowa, two underground natural gas storage facilities in Kansas and two LNG storage peaking units, one in Iowa and one in Minnesota. The three underground natural gas storage facilities and two LNG storage peaking units have a total firm service cycle capacity of 73 Bcf and over 2.0 Bcf of peak day delivery capability. These storage facilities provide Northern Natural Gas with operational flexibility for the daily balancing of its system and provide services to customers to meet their winter peaking and year-round load swing requirements. In 2009, 14% of Northern Natural Gas' transportation and storage revenue was generated from storage services.

Since June 2006, Northern Natural Gas has added 14 Bcf of firm storage cycle capacity through investments and modifications made at its Cunningham, Kansas and Redfield, Iowa storage facilities. This capacity was sold to local distribution companies ("LDC") for terms of 20-21 years.

Northern Natural Gas' system experiences significant seasonal swings in demand and revenue, with the highest demand typically occurring during the months of November through March. This seasonality provides Northern Natural Gas with opportunities to deliver additional value-added services, such as firm and interruptible storage services. Because of its location and multiple interconnections with interstate and intrastate pipelines, Northern Natural Gas is able to access natural gas from both traditional production areas, such as the Hugoton, Permian and Anadarko Basins, and growing supply areas, such as the Rocky Mountains through Trailblazer Pipeline Company, Kinder Morgan Interstate Gas Transmission, Cheyenne Plains Pipeline, Colorado Interstate Gas Pipeline Company ("Colorado Interstate") and Rockies Express Pipeline, as well as from Canadian production areas through Northern Border Pipeline Company, ("Northern Border"), Great Lakes Gas Transmission Limited Partnership ("Great Lakes") and Viking Gas Transmission Company ("Viking"). This supply diversity provides significant flexibility to Northern Natural Gas' system and customers. As a result of Northern Natural Gas' geographic location in the middle of the United States and its many interconnections with other pipelines, Northern Natural Gas has the opportunity to augment its steady end user and LDC revenue by capitalizing on opportunities for shippers to reach additional markets, such as Chicago, Illinois, other parts of the Midwest, and Texas, through interconnects.

Kern River

Kern River, an indirect wholly owned subsidiary of MEHC, owns an interstate natural gas pipeline system that extends from supply areas in the Rocky Mountains to consuming markets in Utah, Nevada and California. Kern River's pipeline system consists of 1,700 miles of natural gas pipelines, including 1,400 miles of mainline section and 300 miles of common facilities, with a design capacity of 1,755,575 Dth per day. Kern River owns the entire mainline section, which extends from the system's point of origination near Opal, Wyoming, through the Central Rocky Mountains area into Daggett, California. The mainline section consists of 1,300 miles of 36-inch diameter pipeline and 100 miles of various laterals that connect to the mainline. The common facilities are jointly owned by Kern River (77% as of December 31, 2009) and Mojave Pipeline Company ("Mojave"), a wholly owned subsidiary of El Paso Corporation, as tenants-in-common. Kern River's ownership percentage in the common facilities will increase or decrease pursuant to the capital contributions made by the respective joint owners. Kern River has exclusive rights to 1,570,600 Dth per day of the common facilities' capacity, and Mojave has exclusive rights to 400,000 Dth per day of capacity. Operation and maintenance of the common facilities are the responsibility of Mojave Pipeline Operating Company, an affiliate of Mojave. Except for quantities of natural gas owned for system operations, Kern River does not own the natural gas that is transported through its system. Kern River's transportation operations are subject to a regulated tariff that is on file with the FERC. The tariff rates are designed to allow Kern River an opportunity to recover its costs and generate a regulated return on equity.

Kern River's 2010 Expansion project will be placed in-service when final approval is received from the Pipeline and Hazardous Materials Safety Administration. Approval is expected in 2010. The project will add an additional 145,000 Dth per day of capacity by increasing the maximum allowable operating pressure from 1,200 pounds per square inch ("psig") to 1,333 psig. Kern River will begin construction of its Apex Expansion project after it receives approval from the FERC. The project is expected to be placed in-service in 2011 and will add an incremental 266,000 Dth per day of capacity.

Kern River has year-round long-term firm natural gas transportation service agreements for 1,755,575 Dth per day of capacity. Pursuant to these agreements, the pipeline receives natural gas on behalf of shippers at designated receipt points, transports the natural gas on a firm basis up to each shipper's maximum daily quantity and delivers thermally equivalent quantities of natural gas at designated delivery points. Each shipper pays Kern River the aggregate amount specified in its long-term firm natural gas transportation service agreement and Kern River's tariff, with such amount consisting primarily of a fixed monthly reservation fee based on each shipper's maximum daily quantity and a commodity charge based on the actual amount of natural gas transported.

These year-round, long-term firm natural gas transportation service agreements expire between September 30, 2011 and April 30, 2018, and have a weighted-average remaining contract term of almost seven years. Shippers on the pipeline include major oil and gas companies or affiliates of such companies, electric generating companies, energy marketing and trading companies, financial institutions and natural gas distribution utilities which provide services in Utah, Nevada and California. As of December 31, 2009, over 98% of the firm capacity has primary delivery points in California, with the flexibility to access secondary delivery points in Nevada and Utah.

Northern Natural Gas and Kern River Competition

Pipelines compete on the basis of cost (including both transportation costs and the relative costs of the natural gas they transport), flexibility, reliability of service and overall customer service. End-users often choose from various alternatives, such as natural gas, electricity, fuel oil and coal, primarily on the basis of price. Legislation and governmental regulations, the weather, the futures market, production costs and other factors beyond the control of Northern Natural Gas and Kern River influence the price of natural gas.

Historically, Northern Natural Gas has been able to provide competitively priced services because of its access to a variety of relatively low cost supply basins, its cost control measures and its relatively high load factor throughput, which lowers the per unit cost of transportation. To date, Northern Natural Gas has avoided any significant pipeline system bypasses or turn-back of firm entitlement. In recent years, Northern Natural Gas has retained and signed long-term contracts with customers such as CenterPoint Energy Minnesota Gas, Xcel Energy Inc. ("Xcel Energy") and Metropolitan Utilities District, which in some cases, because of competition, resulted in lower reservation charges relative to the contracts being replaced.

Northern Natural Gas' major competitors in the Market Area include ANR Pipeline Company, Northern Border and Natural Gas Pipeline Company of America LLC. Other competitors of Northern Natural Gas include Great Lakes and Viking. In the Field Area, Northern Natural Gas competes with a large number of interstate and intrastate pipeline companies where the vast majority of Northern Natural Gas' capacity is used for transportation services provided on a short-term firm basis.

Northern Natural Gas needs to compete aggressively to serve existing load and add new customers and load. Northern Natural Gas has been successful in competing for a significant amount of the increased demand related to residential and commercial needs and the construction of new power plants through its Northern Lights expansion project. The growth related to utilities is driven by population growth and increased commercial and industrial needs. The new power plant growth originates from re-powering coal-fired generation, as well as new combustion and combined-cycle gas-fired generation. The growth also may be supportive of the continued sale of Northern Natural Gas' storage services and Field Area transportation services.

Kern River competes with various interstate pipelines in developing expansion projects and entering into long-term agreements to serve market growth in Southern California; Las Vegas, Nevada; and Salt Lake City, Utah. Kern River also competes with various interstate pipelines and its shippers to market capacity that is unutilized under shorter term transactions. Kern River provides its customers with supply diversity through pipeline interconnections with Northwest Pipeline Corporation, Colorado Interstate, Overland Trails Pipeline, Questar Pipeline Company and Questar Overthrust Pipeline Company. These interconnections, in addition to the direct interconnections to natural gas processing facilities, allow Kern River to access natural gas reserves in Colorado, northwestern New Mexico, Wyoming, Utah and the Western Canadian Sedimentary Basin.

Kern River is the only interstate pipeline that presently delivers natural gas directly from a gas supply basin to end-users in the California market. This enables direct connect customers to avoid paying a "rate stack" (i.e., additional transportation costs attributable to the movement from one or more interstate pipeline systems to an intrastate system within California). Kern River believes that its historic levelized rate structure and access to upstream pipelines, storage facilities and economic Rocky Mountain gas reserves increases its competitiveness and attractiveness to end-users. Kern River believes it has an advantage relative to other competing interstate pipelines because its relatively new pipeline can be economically expanded and will require significantly less capital expenditures than other systems to comply with the Pipeline Safety Improvement Act of 2002 ("PSIA"). Kern River's favorable market position is tied to the availability and relatively favorable price of gas reserves in the Rocky Mountain area, an area that in recent years has attracted considerable expansion of pipeline capacity serving markets other than California and Nevada.

In 2009, Northern Natural Gas had two customers that each accounted for greater than 10% of its revenue and its ten largest customers accounted for 55% of its system-wide transportation and storage revenue. Northern Natural Gas has agreements to retain the vast majority of its two largest customers' volumes through at least 2017. Kern River had one customer who accounted for greater than 10% of its revenue. The loss of any of these significant customers, if not replaced, could have a material adverse effect on Northern Natural Gas' and Kern River's respective businesses.

CE Electric UK

General

CE Electric UK, an indirect wholly owned subsidiary of MEHC, is a holding company which owns two companies that distribute electricity in Great Britain, Northern Electric and Yorkshire Electricity. Northern Electric and Yorkshire Electricity serve 3.8 million end-users and operate in the north-east of England from North Northumberland through Tyne and Wear, County Durham, Tees Valley and Yorkshire to North Lincolnshire, an area covering 10,000 square miles. The principal function of Northern Electric and Yorkshire Electricity is to build, maintain and operate the electricity distribution network through which the end-user receives a supply of electricity. In addition Northern Electric and Yorkshire Electricity, CE Electric UK also owns an engineering contracting business that provides electrical infrastructure contracting services to third parties and a hydrocarbon exploration and development business that is focused on developing integrated upstream gas projects in Europe and Australia.

Electricity Distribution

Northern Electric and Yorkshire Electricity receive electricity from the national grid transmission system and distribute it to end-users' premises using their networks of transformers, switchgear and distribution lines and cables. Substantially all of the end-users in Northern Electric's and Yorkshire Electricity's distribution service areas are connected to the Northern Electric and Yorkshire Electricity networks and electricity can only be delivered to these end-users through their distribution systems, thus providing Northern Electric and Yorkshire Electricity with distribution volume that is relatively stable from year to year. Northern Electric and Yorkshire Electricity each charge fees for the use of their distribution systems to the suppliers of electricity. The suppliers purchase electricity from generators, sell the electricity to end-user customers and use Northern Electric's and Yorkshire Electricity's distribution networks pursuant to an industry standard "Distribution Connection and Use of System Agreement." One supplier, RWE Npower PLC and certain of its affiliates, represented 33% of the total combined distribution revenue of Northern Electric and Yorkshire Electricity in 2009.

The service territory geographically features a diverse economy with no dominant sector. The mix of rural, agricultural, urban and industrial areas covers a broad customer base ranging from domestic usage through farming and retail to major industry including automotives, chemicals, mining, steelmaking and offshore marine construction. The industry within the area is concentrated around the principal centers of Newcastle, Middlesbrough and Leeds.

The price controlled revenue of the regulated distribution companies are set out in the special conditions of the licenses of the companies. The licenses are enforced by the regulator, the Office of Gas and Electricity Markets ("Ofgem") and limit increases (or may require decreases) based upon the rate of inflation, other specified factors and other regulatory action. Changes to the price controls can be made only by agreement between a distribution company and the regulator or, if there is no agreement, following a report on a reference by the regulator to the Competition Commission. It has been the convention in the United Kingdom for regulators to conduct periodic regulatory reviews before making proposals for any changes to the price controls. The price controls have conventionally been based upon a 5-year price control period. The current price control period commenced April 1, 2005 and will be replaced by a new price control commencing April 1, 2010.

Electricity distributed to end-users and the total number of end-users as of and for the years ended December 31 were as follows:

	2009	2008	2007
Electricity distributed (in GWh):			
Northern Electric	15,567	16,563	16,977
Yorkshire Electricity	22,642	24,047	24,281
	38,209	40,610	41,258
Number of end-users (in millions):			
Northern Electric	1.6	1.6	1.6
Yorkshire Electricity	2.2	2.2	2.2
	3.8	3.8	3.8

As of December 31, 2009, Northern Electric's and Yorkshire Electricity's electricity distribution network, on a combined basis, included 18,000 miles of overhead lines, 40,000 miles of underground cables and 700 major substations.

CalEnergy Generation-Foreign

The CalEnergy Generation-Foreign platform consists of MEHC's indirect majority ownership of the Casecnan project, which is a 150 MW combined irrigation and hydroelectric power generation project located on the Casecnan and Taan Rivers on the Philippine island of Luzon. The Company's net owned capacity for the Casecnan project is 128 MW and is subject to disputes with two initial minority shareholders with respect to ownership rights. Refer to Item 3 of this Form 10-K for additional information.

The Casecnan project's sole customer is the Republic of the Philippines ("ROP"). The ROP has provided a performance undertaking under which the Philippine National Irrigation Administration's ("NIA") obligations under the Casecnan Project Agreement, as modified ("Project Agreement"), are guaranteed by the full faith and credit of the ROP. NIA also pays CE Casecnan Water and Energy Company, Inc. ("CE Casecnan") for delivery of water and electricity by CE Casecnan. The Casecnan project carries political risk insurance.

Under the terms of the Project Agreement, CE Casecnan will own and operate the project for a 20-year cooperation period which ends December 11, 2021, after which ownership and operation of the project will be transferred to NIA at no cost on an “as-is” basis. The Casecnan project is dependent upon sufficient rainfall to generate electricity and deliver water. Rainfall varies within the year and from year to year, which is outside the control of CE Casecnan, and impacts the amount of electricity generated and water delivered by the Casecnan project. Rainfall has historically been highest from June through December and lowest from January through May. The contractual terms for water delivery fees and variable energy fees can produce variability in revenue between reporting periods. NIA’s payment obligation under the project agreement is substantially denominated in United States dollars and is the Casecnan project’s sole source of operating revenue.

On June 25, 2006, the Upper Mahiao project’s and on July 25, 2007, the Malitbog and Mahanagdong projects’ separate 10-year cooperation periods ended and the projects, representing a total of 485 MW of net owned contract capacity, were transferred to PNOC-Energy Development Corporation by the Company at no cost on an “as-is” basis.

CalEnergy Generation-Domestic

The subsidiaries comprising the Company’s CalEnergy Generation-Domestic platform own interests in 15 non-utility power projects in the United States. The following table sets out certain information concerning CalEnergy Generation-Domestic’s non-utility power projects in operation as of December 31, 2009:

Operating Project	Facility Net or Contract Capacity (MW)[1]	Net MW Owned[1]	Energy Source	Location	Power Purchase Agreement Expiration	Power Purchaser[2]
CE Generation[3]:						
Natural-Gas Fired:						
Saranac	240	90	Natural Gas	New York	2011	Shell
Power Resources	212	106	Natural Gas	Texas	2011	EDF
Yuma	50	25	Natural Gas	Arizona	2024	SDG&E
Total Natural-Gas Fired	502	221				
Imperial Valley Projects	327	164	Geothermal	California	[4]	[4]
Total CE Generation	829	385				
Cordova	537	537	Natural Gas	Illinois	2019	CECG
Wailuku	10	5	Wailuku River	Hawaii	2023	HELCO
Total CalEnergy Generation-Domestic	1,376	927				

(1) Facility Net or Contract Capacity (MW) represents total plant accredited net generating capacity from the summer of 2009 as approved by MAPP for Cordova and contract capacity for most other projects. Net MW Owned indicates CalEnergy Generation-Domestic’s ownership of the Facility Net or Contract Capacity.

(2) Shell Energy North America (US) L.P. (“Shell”); EDF Trading North America LLC (“EDF”); San Diego Gas & Electric Company (“SDG&E”); Constellation Energy Commodities Group, Inc. (“CECG”); and Hawaii Electric Company (“HELCO”).

(3) MEHC has a 50% ownership interest in CE Generation, LLC (“CE Generation”) whose subsidiaries currently operate ten geothermal plants in the Imperial Valley of California (“Imperial Valley Projects”) and three natural gas-fired power generation facilities.

(4) 82% of the Company’s interests in the Imperial Valley Projects’ Contract Capacity (MW) are sold to Southern California Edison Company under long-term power purchase agreements expiring in 2016 through 2026.

HomeServices

HomeServices, a majority-owned subsidiary of MEHC, is the second largest full-service residential real estate brokerage firm in the United States. In addition to providing traditional residential real estate brokerage services, HomeServices offers other integrated real estate services, including mortgage originations, primarily through joint ventures; title and closing services; property and casualty insurance; home warranties; and other home-related services. HomeServices' real estate brokerage business is subject to seasonal fluctuations because more home sale transactions tend to close during the second and third quarters of the year. As a result, HomeServices' operating results and profitability are typically higher in the second and third quarters relative to the remainder of the year. HomeServices currently operates 300 broker offices in 20 states with about 16,000 sales associates under 21 brand names. The United States residential real estate brokerage business is subject to the general real estate market conditions, is highly competitive and consists of numerous local brokers and agents in each market seeking to represent sellers and buyers in residential real estate transactions.

Other Investments - Electric Transmission Joint Ventures

In December 2007, approval was received from the Public Utility Commission of Texas ("PUCT") to establish Electric Transmission Texas, LLC ("ETT"), a company owned equally by subsidiaries of American Electric Power Company, Inc. ("AEP") and MEHC, to own and operate electric transmission assets in the Electric Reliability Council of Texas ("ERCOT") footprint. The PUCT order also approved initial rates based on a 9.96% after tax rate of return on equity and a debt to equity capital structure of 60:40. In January 2009, the PUCT voted to assign approximately $800 million of transmission investment in support of Competitive Renewable Energy Zones ("CREZ") to ETT. The CREZ projects are currently pending final project specific, PUCT approval before construction begins. Additionally, AEP subsidiaries have transferred to ETT the obligation to build approximately $1.5 billion of transmission projects within its ERCOT footprint. Substantially all of these projects are scheduled for completion by the end of 2017. The majority of these projects are in the process of being reviewed for possible endorsement by ERCOT or negotiated with generation customers. Construction will begin only after these steps are complete.

The City of Garland has appealed the PUCT's decision on assignment of CREZ which could impact the level and timing of capital expenditures. In June 2009, the Texas legislature passed and the Texas governor signed a new law that clarifies the PUCT's authority to grant certificates of convenience and necessity ("CCN") to transmission-only utilities such as ETT. ETT filed for a new, conditional CCN under this law in September 2009 to the PUCT for approval. A final order on this matter is expected in 2010.

Electric Transmission America, LLC ("ETA"), is a company owned equally by subsidiaries of AEP and MEHC to pursue transmission opportunities outside of ERCOT. During the second quarter of 2008, ETA formed joint ventures with Westar Energy, Inc. and a subsidiary of OGE Energy Corp. to build and own new electric transmission assets within the SPP. The Westar Energy, Inc. project includes approximately 110 miles of extra-high voltage transmission in Kansas, while the OGE Energy Corp. project includes approximately 170 miles of extra-high voltage in Oklahoma. Both projects received necessary approval from FERC in December 2008 including a return on equity, inclusive of incentives, of 12.3%. The completion of these projects is subject to obtaining SPP and necessary state regulatory approvals.

The investments are accounted for under the equity method.

Employees

As of December 31, 2009, the Company had approximately 16,300 employees, of which approximately 7,400 are covered by union contracts. The majority of the union employees are employed by PacifiCorp and MidAmerican Energy (the "Utilities") and are represented by the International Brotherhood of Electrical Workers, the Utility Workers Union of America, the International Brotherhood of Boilermakers and the United Mine Workers of America. These collective bargaining agreements have expiration dates ranging through September 2013. HomeServices' sales associates are independent contractors and not employees.

General Regulation

MEHC's subsidiaries are subject to comprehensive governmental regulation which significantly influences their operating environment, prices charged to customers, capital structure, costs and their 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.

Domestic Regulated Public Utility Subsidiaries

The Utilities are subject to comprehensive regulation by state utility commissions, federal agencies, and other state and local regulatory agencies. The more significant aspects of this regulatory framework are described below.

State Regulation

Historically, state utility 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 cost of sales, operation and maintenance expense, depreciation expense and income and other tax expense, reduced by wholesale electric sales and other revenue. State utility 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 utility commissions typically have the authority to review and change rates on their own initiative. States 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.

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

Except for Oregon, Washington and Illinois, the Utilities have an exclusive right to serve electricity customers within their service territories and, in turn, have the obligation to provide electric service to those customers. 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 the Company'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 Washington Utilities and Transportation Commission ("WUTC"). In Illinois, a law that changed how and what electric services are regulated by the Illinois Commerce Commission ("ICC") transitioned traditional electric services to a competitive environment so that all Illinois customers are free to choose their electricity service supplier. MidAmerican Energy has an obligation to serve customers at regulated cost-based rates that leave MidAmerican Energy's system, but later choose to return. To date, there has been no significant loss of customers in Illinois.

PacifiCorp

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

State Regulator	Base Rate Test Period	Adjustment Mechanism[1]
Utah Public Service Commission ("UPSC")	Forecasted or historical with known and measurable changes[2]	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.
		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.
Oregon Public Utility Commission ("OPUC")	Forecasted	Annual transition adjustment mechanism, a mechanism for annual rate adjustments for forecasted net variable power costs; no true-up to actual net variable power costs.
		Renewable adjustment clause to recover the revenue requirement of new renewable resources and associated transmission that are not reflected in general rates.
		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").
Wyoming Public Service Commission ("WPSC")	Forecasted or historical with known and measurable changes[2]	Power cost adjustment mechanism based on forecasted net power costs, later trued-up to actual net power costs, subject to dead bands and customer sharing.
Washington Utilities and Transportation Commission ("WUTC")	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 that qualify under the state's emissions performance standard and are not reflected in general rates.
Idaho Public Utilities Commission ("IPUC")	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	Post test-year adjustment mechanism for major capital additions, a mechanism that allows for rate adjustments outside of the context of a traditional 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.
		Energy cost adjustment clause that allows for an annual update to actual and forecasted net variable power costs.
		Post test-year adjustment mechanism for attrition, a mechanism that allows for an annual adjustment to costs other than net variable power costs.

(1) PacifiCorp has relied on both historical test periods with known and measurable adjustments and forecasted test periods. The WPSC has not issued a final ruling on its preference between historical or forecasted test periods.

PacifiCorp's energy efficiency program costs are collected through separately established rates that are adjusted periodically based on actual and expected costs, as approved by the respective state utility commission.

MidAmerican Energy

The IUB has approved over the past several years a series of electric settlement agreements between MidAmerican Energy, the Iowa Office of Consumer Advocate ("OCA") and other intervenors under which MidAmerican Energy has agreed not to seek a general increase in electric base rates to become effective prior to January 1, 2014, unless its Iowa jurisdictional electric return on equity for any twelve-month period covered by the applicable agreement falls below 10%, computed as prescribed in each respective agreement. Prior to filing for a general increase in electric rates, MidAmerican Energy is required to conduct 30 days of good faith negotiations with the signatories to the settlement agreements to attempt to avoid a general increase in rates. As a party to the settlement agreements, the OCA has agreed not to request or support any decrease in MidAmerican Energy's Iowa electric base rates to become effective prior to January 1, 2014. The settlement agreements specifically allow the IUB to approve or order electric rate design or cost-of-service rate changes that could result in changes to rates for specific customers as long as such changes do not result in an overall increase in revenue for MidAmerican Energy. Additionally, the settlement agreements also each provide that revenue associated with Iowa retail electric returns on equity within specified ranges will be shared with customers. The following table summarizes the ranges of Iowa electric returns on equity subject to revenue sharing under each of the remaining settlement agreements, the percent of revenue within those ranges to be assigned to customers, and the method by which the liability to customers will be settled.

Date Approved by the IUB	**Years Covered**	**Range of Iowa Electric Return on Equity Subject to Sharing**	**Customers' Share of Revenue Within Range**	**Method to be Used to Settle Liability to Customers**[1]
October 17, 2003	2006 - 2010	11.75% - 13%	40%	Credits against the cost of new generation plant in Iowa
		13% - 14%	50%	
		Above 14%	83.3%	
January 31, 2005	2011	Same	Same	Credits to customer bills in 2012
April 18, 2006	2012	Same	Same	Credits to customer bills in 2013
July 27, 2007[2]	2013	Same	Same	Credits against the cost of wind-powered generation projects covered by this agreement

(1) Revenue sharing credits recorded against the cost of new generation totaled $354 million as of December 31, 2009.

(2) If a rate case is filed pursuant to the 10% threshold, as discussed above, the revenue sharing arrangement for 2013 is changed such that the amount to be shared with customers will be 83.3% of revenue associated with Iowa electric operating income in excess of returns on equity allowed by the IUB as a result of the rate case.

MidAmerican Energy is exposed to fluctuations in electric energy costs relating to retail sales in Iowa and Illinois as it does not have energy cost adjustment mechanisms through which fluctuations in electric energy costs can be recovered in those jurisdictions. In Illinois, base rates were adjusted to include recoveries at average 2004/2005 energy cost levels beginning January 1, 2007, and regulatory approval is required for any base rate changes. MidAmerican Energy may not petition for reinstatement of the Illinois fuel adjustment clause until November 2011.

MidAmerican Energy's cost of gas is collected for each jurisdiction in its gas rates through a uniform PGA, which is updated monthly to reflect changes in actual costs. Subject to prudence reviews, the PGA accomplishes a pass-through of MidAmerican Energy's cost of gas to its customers and, accordingly, has no direct effect on net income. MidAmerican Energy's energy efficiency program costs are collected through separately established rates that are adjusted annually based on actual and expected costs, as approved by the respective state utility commission. As such, recovery of energy efficiency 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 Natural Gas Act ("NGA"), the Energy Policy Act and other federal statutes. The FERC regulates rates for interstate sales of electricity in wholesale markets; transmission of electric power, including pricing and expansion of transmission systems; electric system reliability; utility holding companies; accounting; securities issuances; and other matters, including construction and operation of hydroelectric projects. 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. The Utilities have implemented programs that facilitate compliance with the FERC regulations described below, including having instituted compliance monitoring procedures. MidAmerican Energy is also subject to regulation by the Nuclear Regulatory Commission ("NRC") pursuant to the Atomic Energy Act of 1954, as amended ("Atomic Energy Act"), with respect to the operation of the Quad Cities Station.

<u>Wholesale Electricity and Capacity</u>

The FERC regulates the Utilities' rates charged to wholesale customers for electricity and transmission capacity and related services. Most of the Utilities' wholesale electric 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 the Utilities' market-based pricing authority. Each utility must demonstrate the lack of market power in order to charge market-based rates for sales of wholesale electricity and electric generation capacity in their respective market areas. PacifiCorp's next triennial filing is due in June 2010 and MidAmerican Energy's are due in June and December 2011. Under the FERC's market-based rules, the Utilities 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. The Utilities are currently authorized to sell at market-based rates.

<u>Transmission</u>

PacifiCorp's wholesale transmission services are regulated by the FERC under cost-based regulation subject to PacifiCorp's Open Access Transmission Tariff ("OATT"). These services are offered on a non-discriminatory basis, meaning that all potential customers are provided an equal opportunity to access the transmission system. Effective September 1, 2009, MidAmerican Energy turned over functional control of its transmission system to the MISO as a transmission-owning member, as approved by the FERC, and no longer offers transmission services. While the MISO is responsible for directing the operation of MidAmerican Energy's transmission system, MidAmerican Energy retains ownership of its transmission assets and, accordingly, is subject to the FERC's reliability standards discussed below. The Company's transmission businesses are managed and operated independently from its wholesale marketing businesses in accordance with the FERC Standards of Conduct.

In February 2007, the FERC adopted a final rule in Order No. 890 designed to strengthen the pro-forma OATT by providing greater specificity and increasing transparency. The most significant revisions to the pro forma OATT relate to the development of more consistent methodologies for calculating available transfer capability, changes to the transmission planning process, changes to the pricing of certain generator and energy imbalances to encourage efficient scheduling behavior and changes regarding long-term point-to-point transmission service, including the addition of conditional firm long-term point-to-point transmission service, and generation re-dispatch. The FERC has issued rules through a set of subsequent orders clarifying Order No. 890. As a transmission provider with an OATT on file with the FERC, PacifiCorp is required to comply with the requirements of the new rule. PacifiCorp made its first compliance filing amending its OATT in July 2007. The FERC has continued to issue rules through a set of subsequent orders clarifying Order No. 890. In response to these various orders, PacifiCorp has made several required compliance filings.

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. The Utilities must comply with all applicable standards. Compliance, enforcement and monitoring oversight of these standards is carried out by the FERC, the WECC for PacifiCorp and the Midwest Reliability Organization ("MRO") for MidAmerican Energy. During 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 in principle with the WECC. The results of the settlement will not have a material impact on the Company's consolidated financial results. In September 2008, the MRO issued a public report to the NERC stating MidAmerican Energy was found to be 100% compliant with all standards addressed in the latest MRO on-site audit conducted in August 2008.

Hydroelectric Relicensing – Klamath River Hydroelectric Facilities

PacifiCorp's Klamath hydroelectric system is the only 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 16 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.

Nuclear Regulatory Commission

MidAmerican Energy is subject to the jurisdiction of the NRC with respect to its license and 25% ownership interest in the Quad Cities Station. Exelon Generation, the operator and 75% owner of Quad Cities Station, is under contract with MidAmerican Energy to secure and keep in effect all necessary NRC licenses and authorizations.

The NRC regulates the granting of permits and licenses for the construction and operation of nuclear generating stations and regularly inspects such stations for compliance with applicable laws, regulations and license terms. Current licenses for the Quad Cities Station provide for operation until December 14, 2032. The NRC review and regulatory process covers, among other things, operations, maintenance, and environmental and radiological aspects of such stations. The NRC may modify, suspend or revoke licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of such licenses.

Federal regulations provide that any nuclear operating facility may be required to cease operation if the NRC determines there are deficiencies in state, local or utility emergency preparedness plans relating to such facility, and the deficiencies are not corrected. Exelon Generation has advised MidAmerican Energy that an emergency preparedness plan for Quad Cities Station has been approved by the NRC. Exelon Generation has also advised MidAmerican Energy that state and local plans relating to Quad Cities Station have been approved by the Federal Emergency Management Agency.

MidAmerican Energy maintains financial protection against catastrophic loss associated with its interest in the Quad Cities Station through a combination of insurance purchased by Exelon Generation (the operator and joint owner of the Quad Cities Station), insurance purchased directly by MidAmerican Energy, and the mandatory industry-wide loss funding mechanism afforded under the Price-Anderson Amendments Act of 1988, which was amended and extended by the Energy Policy Act of 2005. The general types of coverage are: nuclear liability, property coverage and nuclear worker liability.

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, regulations and state regulatory agencies. The Mine Improvement and New Emergency Response Act of 2006 ("MINER Act"), enacted in June 2006, amended previous mine safety and health laws to improve mine safety and health and accident preparedness. PacifiCorp is required to develop a written emergency response plan specific to each underground mine it operates. These plans must be reviewed by MSHA every six months. It also requires every mine to have at least two rescue teams located within one hour, and it limits the legal liability of rescue team members and the companies that employ them. The MINER Act also increases civil and criminal penalties for violations of federal mine safety standards and gives MSHA the ability 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 the penalties or fines.

United States Interstate Natural Gas Pipeline Subsidiaries

The natural gas pipeline and storage operations of the Company's United States interstate pipeline subsidiaries are regulated by the FERC, which administers, most significantly, the NGA and the Natural Gas Policy Act of 1978. Under this authority, the FERC regulates, among other items, (a) rates, charges, terms and conditions of service and (b) the construction and operation of United States pipelines, storage and related facilities, including the extension, expansion or abandonment of such facilities.

Northern Natural Gas continues to use a modified straight fixed variable rate design methodology, whereby substantially all fixed costs, including a return on invested capital and income taxes, are collected through reservation charges, which are paid by firm transportation and storage customers regardless of volumes shipped. Commodity charges, which are paid only with respect to volumes actually shipped, are designed to recover the remaining, primarily variable, cost. In an order issued in November 2009 pursuant to Section 5 of the NGA, the FERC is investigating the reasonableness of Northern Natural Gas' rates. Kern River's rates have historically been set using a "levelized cost-of-service" methodology so that the rate is constant over the contract period. This levelized cost of service has been achieved by using a FERC-approved depreciation schedule in which depreciation increases as interest expense decreases.

FERC regulations also restrict each pipeline's marketing affiliates' access to United States interstate pipeline natural gas transmission customer data and place certain conditions on services provided by the United States interstate pipelines to their marketing affiliates.

United States interstate natural gas pipelines are also subject to regulations by a federal agency within the United States Department of Transportation ("DOT"), pursuant to the Natural Gas Pipeline Safety Act of 1968, as amended, which establishes safety requirements in the design, construction, operation and maintenance of interstate natural gas facilities, and the PSIA, which implemented additional safety and pipeline integrity regulations for high consequence areas. The regulation also requires Northern Natural Gas and Kern River to complete baseline integrity assessments on their pipeline systems by December 17, 2012. Each pipeline is on schedule to have this work completed by December 2011.

In addition to FERC and DOT regulation, certain operations are subject to oversight by state regulatory commissions.

United Kingdom Electricity Distribution Companies

Northern Electric and Yorkshire Electricity, as holders of electricity distribution licenses, are subject to regulation by the Gas and Electricity Markets Authority ("GEMA"). GEMA discharges certain of its powers through its staff within Ofgem. Each of fourteen licensed distribution network operators ("DNOs") distributes electricity from the national grid system to end use customers within their respective distribution service areas.

DNOs are subject to price controls, enforced by Ofgem, that limit the revenue that may be recovered and retained from their electricity distribution activities. The regulatory regime that has been applied to electricity distributors in the UK encourages companies to look for efficiency gains in order to improve profits. The distribution price control formula also adjusts the revenue received by DNOs to reflect the rate of inflation (as measured by the retail price index), the quality of service delivered by the licensee's distribution system and system losses (i.e., the difference between the number of units entering and leaving the licensee's system). The price controls that apply until March 31, 2010, also vary allowed revenue by reference to the change in the number of units distributed, but this will cease commencing April 1, 2010. Currently, price controls are established every five years, although the formula has been, and may be, reviewed at the regulator's discretion. The procedure and methodology adopted at a price control review are at the reasonable discretion of Ofgem. Historically, Ofgem's judgment of the future allowed revenue of licensees has been based upon, among other things:

- actual operating costs of each of the licensees;
- pension deficiency payments of each of the licensees;
- operating costs which each of the licensees would incur if it were as efficient as, in Ofgem's judgment, the more efficient licensees;
- taxes that each licensee is expected to pay;
- regulatory value ascribed to and the allowance for depreciation related to the distribution network assets;
- rate of return to be allowed on investment in the distribution network assets by all licensees; and
- financial ratios of each of the licensees and the license requirement for each licensee to maintain an investment grade status.

The current electricity distribution price control became effective in April 2005 and will continue through March 2010. The most recent review will result in a new formula that will commence April 1, 2010 and is expected to continue in force for five years. A resetting of the formula requires the consent of the DNO; however, license modifications may be unilaterally imposed by Ofgem without such consent following review by the British competition commission. Northern Electric and Yorkshire Electricity have each agreed to Ofgem's proposals for the resetting of the formula commencing April 1, 2010.

A number of incentive schemes also operate within the current price control period to encourage DNOs to provide an appropriate quality of service to end users with specified payments to be made for failures to meet prescribed standards of service. The aggregate of these payments is uncapped, but may be excused in certain prescribed circumstances that are generally beyond the control of the DNO.

The most recent price control review conducted by Ofgem led to an increase in allowed revenue for Northern Electric and Yorkshire Electricity. As a result, Northern Electric is expected to be permitted to increase its regulated revenue by 7.7% (plus inflation as measured by the United Kingdom's Retail Prices Index) in each of the next five regulatory years commencing April 1, 2010. Yorkshire Electricity may increase its regulated revenue by 6.5% (plus inflation) in each year over the same period.

Ofgem also monitors DNO compliance with license conditions and enforces the remedies resulting from any breach of condition. License conditions include the prices and terms of service, financial strength of the DNO, the provision of information to Ofgem and the public, as well as maintaining transparency, non-discrimination and avoidance of cross-subsidy in the provision of such services. Ofgem also monitors and enforces certain duties of a DNO set out in the Electricity Act of 1989 including the duty to develop and maintain an efficient, coordinated and economical system of electricity distribution. Under the Utilities Act 2000, the regulators are able to impose financial penalties on DNOs who contravene any of their license duties or certain of their duties under the Electricity Act 1989, as amended, or who are failing to achieve a satisfactory performance in relation to the individual standards prescribed by GEMA. Any penalty imposed must be reasonable and may not exceed 10% of the licensee's revenue.

Independent Power Projects

Foreign

The Philippine Congress has passed the Electric Power Industry Reform Act of 2001 ("EPIRA"), which is aimed at restructuring the Philippine power industry, privatizing the National Power Corporation and introducing a competitive electricity market, among other initiatives. The implementation of EPIRA may impact the Company's future operations in the Philippines and the Philippine power industry as a whole, the effect of which is not yet known as changes resulting from EPIRA are ongoing.

Domestic

Both the Cordova and Power Resources Projects are Exempt Wholesale Generators ("EWG") under the Energy Policy Act while the remaining domestic projects are currently certified as Qualifying Facilities ("QF") under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Both EWGs and QFs are generally exempt from compliance with extensive federal and state regulations that control the financial structure of an electric generating plant and the prices and terms at which electricity may be sold by the facilities. In addition, Cordova, Yuma Cogeneration Associates, Saranac Power Partners, L.P. and Power Resources Limited have obtained authority from the FERC to sell their power using market-based rates.

EWGs are permitted to sell capacity and electricity only in the wholesale markets, not to end users. Additionally, utilities are required to purchase electricity produced by QFs at a price that does not exceed the purchasing utility's "avoided cost" and to sell back-up power to the QFs on a non-discriminatory basis, unless they have successfully petitioned the FERC for an exemption from this purchase requirement for QFs of greater than 20 MW. Avoided cost is defined generally as the price at which the utility could purchase or produce the same amount of power from sources other than the QF on a long-term basis. The Energy Policy Act eliminated the purchase requirement for utilities with respect to new contracts under certain conditions. New QF contracts are also subject to FERC rate filing requirements, unlike QF contracts entered into prior to the Energy Policy Act. FERC regulations also permit QFs and utilities to negotiate agreements for utility purchases of power at rates other than the utilities' avoided cost.

Residential Real Estate Brokerage Company

HomeServices is regulated by the United States Department of Housing and Urban Development ("HUD"), most significantly under the Real Estate Settlement Procedures Act ("RESPA"), and by state agencies where it operates. RESPA primarily governs the real estate settlement process by mandating all parties fully inform borrowers about all closing costs, lender servicing and escrow account practices, and business relationships between closing service providers and other parties to the transaction. In November 2008, as a result of a rulemaking proceeding initiated earlier in the year the HUD adopted a new RESPA rule that updated procedures and forms, enhanced notice and communication requirements and further clarified the scope of business relationships among closing service providers. The Company does not believe the new rule will materially affect HomeServices' ability to do business.

Environmental Laws and Regulation

The Company is subject to federal, state, local and foreign laws and regulations regarding air and water quality, renewable portfolio standards, climate change, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact the Company'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, local and international 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 the Company is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. The Company believes it is in material compliance with all applicable laws and regulations.

Refer to the Liquidity and Capital Resources section of Item 7 of this Form 10-K for additional information regarding environmental laws and regulation and the Company's forecasted environmental-related capital expenditures.

Item 1A. Risk Factors

We are subject to numerous risks, including, but not limited to, those set forth 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 are a holding company and depend on distributions from subsidiaries, including joint ventures, to meet our obligations.

We are a holding company with no material assets other than the equity investments in our subsidiaries and joint ventures, collectively referred to as our subsidiaries. Accordingly, cash flows and the ability to meet our obligations are largely dependent upon the earnings of our subsidiaries and the payment of such earnings to us in the form of dividends or other distributions. Our subsidiaries are separate and distinct legal entities that do not guarantee the payment of any of our obligations or have an obligation, contingent or otherwise, to pay directly, or to make funds available for the payment of, amounts due pursuant to our senior and subordinated debt securities or our other obligations. Distributions from subsidiaries may also be limited by:

- their respective earnings, capital requirements, and required debt and preferred stock payments;
- the satisfaction of certain terms contained in financing, ring-fencing or organizational documents; and
- regulatory restrictions which limit the ability of our regulated utility subsidiaries to distribute profits.

We are substantially leveraged, the terms of our senior and subordinated indebtedness do not restrict the incurrence of additional indebtedness by us or our subsidiaries, and our senior and subordinated debt is structurally subordinated to the indebtedness of our subsidiaries, each of which could adversely affect our consolidated financial results.

A significant portion of our capital structure is debt and we expect to incur additional indebtedness in the future to fund acquisitions, capital investments or the development and construction of new or expanded facilities. As of December 31, 2009, we had the following outstanding obligations:

- senior indebtedness of $5.371 billion;
- subordinated indebtedness of $590 million, consisting of $237 million of trust preferred securities held by third parties and $353 million held by Berkshire Hathaway and its affiliates; and
- guarantees and letters of credit in respect of subsidiary and equity investment indebtedness aggregating $91 million.

Our consolidated subsidiaries also have significant amounts of outstanding indebtedness, which totaled $13.791 billion as of December 31, 2009. These amounts exclude (a) trade debt, (b) preferred stock obligations, (c) letters of credit in respect of subsidiary indebtedness, and (d) our share of the outstanding indebtedness of our own or our subsidiaries' equity investments.

Given our substantial leverage, we may not have sufficient cash to service our debt, which could limit our ability to finance future acquisitions, develop and construct additional projects, or operate successfully under adverse conditions, including those brought on by declining national and global economies and unfavorable financial markets, such as those experienced in the United States in 2008 and 2009. Our leverage could also impair our credit quality or the credit quality of our subsidiaries, making it more difficult to finance operations or issue future indebtedness on favorable terms, and could result in a downgrade in debt ratings by credit rating agencies.

The terms of our senior and subordinated debt do not limit our ability or the ability of our subsidiaries to incur additional debt or issue preferred stock. Accordingly, we or our subsidiaries could enter into acquisitions, new financings, refinancings, recapitalizations or other highly leveraged transactions that could significantly increase our or our subsidiaries' total amount of outstanding debt. The interest payments needed to service this increased level of indebtedness could adversely affect our consolidated financial results. Further, if an event of default accelerates a repayment obligation and such acceleration results in an event of default under some or all of our other indebtedness, we may not have sufficient funds to repay all of the accelerated indebtedness, and the other risks described under "Our Corporate and Financial Structure Risks" may be magnified as well.

Because we are a holding company, the claims of our senior and subordinated debt holders are structurally subordinated with respect to the assets and earnings of our subsidiaries. Therefore, the rights of our creditors to participate in the assets of any subsidiary in the event of a liquidation or reorganization are subject to the prior claims of the subsidiary's creditors and preferred shareholders. In addition, a significant amount of the stock or assets of our operating subsidiaries is directly or indirectly pledged to secure their financings and, therefore, may be unavailable as potential sources of repayment of our senior and subordinated debt.

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

Our senior unsecured long-term debt is rated investment grade by various rating agencies. We cannot assure that our senior unsecured long-term debt 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 agreement 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.

Similarly, any downgrade or other event negatively affecting the credit ratings of our subsidiaries could make their costs of borrowing higher or access to funding sources more limited, which in turn could cause us to provide liquidity in the form of capital contributions or loans to such subsidiaries, thus reducing our and our subsidiaries' liquidity and borrowing capacity.

Most of our large customers, suppliers and counterparties require sufficient creditworthiness in order to enter into transactions, particularly in the wholesale energy markets. If our credit ratings or the credit ratings of our subsidiaries were to decline, especially below investment grade, financing costs and borrowing 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 transactions with us or our subsidiaries.

Our majority shareholder, Berkshire Hathaway, could exercise control over us in a manner that would benefit Berkshire Hathaway to the detriment of our creditors.

Berkshire Hathaway is our majority owner and has control over all decisions requiring shareholder approval, including the election of our directors. In circumstances involving a conflict of interest between Berkshire Hathaway and our creditors, Berkshire Hathaway could exercise its control in a manner that would benefit Berkshire Hathaway to the detriment of our creditors.

Our Business Risks

Much of our growth has been achieved through acquisitions, and additional acquisitions may not be successful.

Much of our growth has been achieved through acquisitions. Future acquisitions may range from buying individual assets to the purchase of entire businesses. We will continue to investigate and pursue opportunities for future acquisitions that we believe may increase shareholder value and expand or complement existing businesses. We may participate in bidding or other negotiations at any time for such acquisition opportunities which may or may not be successful. Any transaction that does take place may involve consideration in the form of cash or debt or equity securities.

Completion of any acquisition entails numerous risks, including, among others, the:

- failure to complete the transaction for various reasons, such as the inability to obtain the required regulatory approvals, materially adverse developments in the potential acquiree's business or financial condition or successful intervening offers by third parties;
- failure of the combined business to realize the expected benefits or to meet regulatory commitments; and
- need for substantial additional capital and financial investments.

An acquisition could cause an interruption of, or loss of momentum in, the activities of one or more of our businesses. The diversion of management's attention and any delays or difficulties encountered in connection with the approval and integration of the acquired operations could adversely affect our combined businesses and financial results and could impair our ability to realize the anticipated benefits of the acquisition.

We cannot assure you that future acquisitions, if any, or any related integration efforts will be successful, or that our ability to repay our obligations will not be adversely affected by any future acquisitions.

Our regulated businesses are subject to extensive regulations and legislation that affect their operations and costs. These regulations and laws are complex, dynamic and subject to change.

Our businesses are subject to numerous regulations and laws enforced by regulatory agencies. In the United States, these regulatory agencies include, among others, the FERC, the EPA, the NRC, and the DOT. In addition, our domestic utility subsidiaries are subject to state utility regulation in each state in which they operate. In the United Kingdom, these regulatory agencies include, among others, GEMA, which discharges certain of its powers through its staff within Ofgem.

Regulations affect almost every aspect of 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; setting rates charged to customers; establishing capital structures and issuing debt or equity securities; engaging in transactions between our domestic utilities and other subsidiaries and affiliates; and paying dividends. Regulations are subject to ongoing policy initiatives, and we cannot predict the future course of changes in regulatory laws, regulations and orders, or the ultimate effect that regulatory changes may have on us. However, such changes could adversely affect our consolidated financial results through higher capital expenditures and operating costs and an overall change in how we operate our business. For example, such changes could result in, but are not limited to, increased retail competition within our subsidiaries' service territories; new environmental requirements, including the implementation of RPS and greenhouse gas ("GHG") emission reduction goals; the issuance of stricter air quality standards and the implementation of energy efficiency mandates; the acquisition by a municipality of our subsidiaries' distribution facilities (by a vote in favor of a public utility district under state law or by condemnation, negotiation or legislation under state law); or a negative impact on our subsidiaries' current transportation and cost recovery arrangements, including income tax recovery.

Federal and state energy regulation is one of the more challenging aspects of managing utility operations. The United States Congress and federal policy makers, with President Obama's support, are considering comprehensive climate change legislation, such as the American Clean Energy and Security Act of 2009 ("Waxman-Markey bill") that was passed by the United States House of Representatives in June 2009. In addition to a federal RPS, which would require utilities to obtain a portion of their energy from certain qualifying renewable sources and energy efficiency measures, the bill requires a reduction in GHG emissions beginning in 2012, with emission 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. In September 2009, a similar bill was introduced in the United States Senate by Senators Barbara Boxer and John Kerry, which would require an initial reduction in GHG emissions beginning in 2012 with emission reduction targets consistent with the Waxman-Markey bill, with the exception of the 2020 target, which requires 20% reduction below 2005 levels. In December 2009, the EPA issued a proposed determination that carbon dioxide ("CO_2") emissions can be regulated under the Clean Air Act and stated its intent to issue regulations limiting the release of CO_2 from sources including fossil fuel based electric generating facilities.

The impact of pending federal, regional, state and international accords, legislation or regulation related to climate change, including new laws, regulations or rules limiting GHG emissions could have a material adverse impact on us. Our regulated subsidiaries have significant coal-fired generating facilities that 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 quantified at this time. In addition to unknown factors, known factors include, but are not limited to, the magnitude and timing of GHG emissions reduction requirements; the cost, availability and effectiveness of emission control technology; the price and availability of offsets and allowances used for compliance; government-imposed compliance costs; and the existence and nature of incremental cost recovery mechanisms. To the extent that our regulated subsidiaries are not allowed by their regulators to recover or cannot otherwise recover the costs to comply with climate change requirements, these requirements could have a material adverse impact 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 sales volumes, this could have a material adverse impact on our consolidated financial results.

New and expanded regulations imposed by policy makers, court systems, and industry restructuring have imposed changes on the industry. The following are examples of recent changes to our regulatory environment that have impacted us:

- *Energy Policy Act of 2005* - The United States Energy Policy Act impacts many segments of the energy industry. The United States Congress granted the FERC additional authority in the Energy Policy Act which expanded its role from a regulatory body to an enforcement agency. To implement the law, the FERC adopted new regulations and issued regulatory decisions addressing electric system reliability, electric transmission planning, operation, expansion and pricing, regulation of utility holding companies, market transparency for natural gas marketing and transportation, and enforcement authority, including the ability to assess civil penalties of up to $1 million per day per violation for non-compliance with regulations in either the electric or natural gas areas of the FERC's jurisdiction. The FERC has essentially completed its implementation of the Energy Policy Act, and the emphasis of its recent decisions is on reporting and compliance. In that regard, the FERC has vigorously exercised its enforcement authority by imposing significant civil penalties for violations of its rules and regulations. In addition, as a result of past events affecting electric reliability, the Energy Policy Act requires federal agencies, working together with non-governmental organizations charged with electric reliability responsibilities, to adopt and implement measures designed to ensure the reliability of electric transmission and distribution systems. Since the adoption of the Energy Policy Act, the FERC has approved numerous electric reliability and critical infrastructure protection standards developed by the NERC. A transmission owner's reliability compliance issues with these and future standards could result in financial penalties. In FERC Order No. 693, the FERC implemented its authority to impose penalties of up to $1 million per day per violation for failure to comply with electric reliability standards. The adoption of these and future electric reliability standards has imposed more comprehensive and stringent requirements on us and our public utility subsidiaries, which has increased compliance costs. It is possible that the cost of complying with these and any additional standards adopted in the future could adversely affect our consolidated financial results.

- *FERC Orders* – The FERC has issued a series of orders to encourage competition in natural gas markets, the expansion of existing pipelines and the construction of new pipelines and to foster greater competition in wholesale power markets by reducing barriers to entry in the provision of transmission service. As a result of FERC Order Nos. 636 and 637, in the natural gas markets, LDCs and end-use customers have additional choices in this more competitive environment and may be able to obtain service from more than one pipeline to fulfill their natural gas delivery requirements. Any new pipelines that are constructed could compete with our pipeline subsidiaries to service customer needs. Increased competition could reduce the volumes of gas transported by our pipeline subsidiaries or, in the absence of long-term fixed rate contracts, could force our pipeline subsidiaries to lower their rates to remain competitive. This could adversely affect our pipeline subsidiaries' financial results. In FERC Order Nos. 888, 889 and 890, the FERC required electric utilities to adopt a proforma OATT, by which transmission service would be provided on a just, reasonable and not unduly discriminatory or preferential basis. The rules adopted by these orders promote transparency and consistency in the administration of the OATT, increase the ability of customers to access new generating resources and promote efficient utilization of transmission by requiring an open, transparent and coordinated transmission planning process. Together with the increased reliability standards required of transmission providers, the costs of operating the transmission system and providing transmission service have increased and, to the extent such increased costs are not recovered in rates charged to customers, they could adversely affect our consolidated financial results.

- *Hydroelectric Relicensing* – Currently, we are engaged in the FERC relicensing process for our Klamath hydroelectric system, for which the operating license has expired. We are currently operating under an annual license. Through a settlement signed in February 2010 with relicensing stakeholders, disposition of the relicensing process and a path toward dam transfer and removal by a third party may occur as an alternative to relicensing. Hydroelectric relicensing is a political and public regulatory process involving sensitive resource issues and uncertainties. We cannot predict with certainty 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 PacifiCorp will be willing to meet the relicensing requirements to continue operating its hydroelectric generating facilities. Loss of hydroelectric resources or additional commitments arising from relicensing could adversely affect our consolidated financial results.

Our subsidiaries are subject to numerous environmental, health, safety and other laws, regulations and other requirements that could adversely affect our consolidated financial results.

Operational Standards

Our subsidiaries are subject to numerous environmental, health, safety and other laws, regulations and other requirements affecting many aspects of their present and future operations, including, among others:

- the EPA's Clean Air Interstate Rule ("CAIR"), which established cap-and-trade programs to reduce SO_2 and NO_x emissions starting in 2009 to address alleged contributions to downwind non-attainment with the revised National Ambient Air Quality Standards;
- the implementation of federal and state RPS;
- other laws or regulations that establish or could establish standards for GHG emissions, water quality, wastewater discharges, solid waste and hazardous waste;
- the DOT regulations, effective in 2004, that establish mandatory inspections for all natural gas transmission pipelines in high-consequence areas within 10 years. These regulations require pipeline operators to implement integrity management programs, including more frequent inspections, and other safety protections in areas where the consequences of potential pipeline accidents pose the greatest risk to life and property; and
- the provisions of the MINER Act to improve underground coal mine safety and emergency preparedness.

These and related laws, regulations and orders generally require our subsidiaries to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals.

Compliance with environmental, health, safety, and other laws, regulations and other requirements 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 regulations could be prohibitively expensive. As a result, some facilities may be required to shut down or alter their operations. Further, our subsidiaries may not be able to obtain or maintain all required environmental regulatory approvals for their 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 our subsidiaries from operating their facilities, developing new facilities, expanding existing facilities or favorably locating new facilities. If our subsidiaries fail to comply with all applicable environmental requirements, they may be subject to penalties and fines or other sanctions. The costs of complying with current or new environmental, health, safety and other laws, regulations and other requirements could adversely affect our consolidated financial results. Not being able to operate existing facilities or develop new electric generating facilities to meet customer energy needs could require our subsidiaries to increase their purchases of power from the wholesale markets which could increase market and price risks and adversely affect our consolidated financial results.

Proposals for voluntary initiatives and mandatory controls are being discussed both in the United States and worldwide, such as the December 2009 climate conference in Copenhagen, Denmark, to reduce greenhouse gases such as CO_2 (a by-product of burning fossil fuels) and methane (the primary component of natural gas). These actions could result in increased costs to (a) operate and maintain our facilities, (b) install new emission controls on our facilities and (c) administer and manage compliance with any GHG emissions program, such as through the purchase of emission credits as may be required. These actions could also increase the demand for natural gas, causing increased natural gas prices, thereby adversely affecting our operations. See the preceding risk titled, "Our regulated businesses are subject to extensive regulations and legislation that affect their operations and costs. These regulations and laws are complex, dynamic and subject to change" for more detail on the United States' efforts and a discussion of the Waxman-Markey bill.

Site Cleanup and Contamination

Environmental, health, safety and other laws, regulations and requirements also impose obligations to remediate contaminated properties or to pay for the cost of such remediation, often by parties that did not actually cause the contamination. Our subsidiaries are generally responsible for on-site liabilities, and in some cases off-site liabilities, associated with the environmental condition of their assets, including power generating facilities and electric and natural gas transmission and distribution assets that our subsidiaries have acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with acquisitions, we or our subsidiaries may obtain or require indemnification against some environmental liabilities. If our subsidiaries incur a material liability, or the other party to a transaction fails to meet its indemnification obligations, our subsidiaries could suffer material losses. Our subsidiaries have established reserves to recognize their estimated obligations for known remediation liabilities, but such estimates may change materially over time. PacifiCorp is required to fund its portion of the costs of mine reclamation at its coal mining operations, which include principally site restoration. Also, MidAmerican Energy is required to fund its portion of the costs of decommissioning the Quad Cities Station when it is retired from service, which may include site remediation or decontamination. In addition, future events, such as changes in existing laws or policies or their enforcement, or the discovery of currently unknown contamination, may give rise to additional remediation liabilities that may be material.

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

Public Utility Subsidiaries – State Rate Proceedings

The Utilities establish rates for their 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 additional uncertainty associated with the approval proceedings.

Each state sets retail rates based in part upon the state utility 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 will not be sufficient to cover those costs. Each state utility commission generally sets rates based on a test year established in accordance with that commission's policies. The test year data adopted by a regulatory commission may create a lag between the incurrence of a cost and its recovery in rates. They also decide the allowed levels of expense and investment that they deem are just and reasonable in providing service. The state regulatory commissions may disallow recovery in rates for any costs that do not meet such standard. State regulatory commissions also decide the allowed rate of return the Utilities will be given an opportunity to earn on their sources of capital.

In Iowa, MidAmerican Energy has agreed not to seek a general increase in electric base rates to become effective prior to January 1, 2014 unless its Iowa jurisdictional electric return on equity for any twelve-month period falls below 10%. MidAmerican Energy expects to continue to make significant capital expenditures to maintain and improve the reliability of its generation, transmission and distribution facilities to reduce emissions and to support new business and customer growth. As a result, MidAmerican Energy's financial results may be adversely affected if it is not able to deliver electricity in a cost-efficient manner and is unable to offset inflation and the cost of infrastructure investments with cost savings or additional sales.

In certain states, the Utilities are not permitted to pass through energy cost increases in their electric rates without a general rate case. Any significant increase in fuel costs for electricity generation or purchased power costs could have a negative impact on PacifiCorp or MidAmerican Energy, 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.

Public Utility Subsidiaries – FERC Jurisdiction

The FERC establishes cost-based rates under which PacifiCorp provides transmission services to wholesale markets and retail markets in states that allow retail competition and establishes cost-based rates associated with MidAmerican Energy's transmission facilities. The FERC also has responsibility for approving both cost- and market-based rates under which both these companies sell electricity at wholesale, has licensing authority over most of PacifiCorp's 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 may (pursuant to pending or future proceedings) revoke or restrict the ability of our public utility subsidiaries to sell electricity at market-based rates, which could adversely affect our consolidated financial results. As a transmission owning member of the MISO, MidAmerican Energy is also subject to MISO-directed modifications of market rules, which are subject to FERC approval and operational procedures. The FERC may also impose substantial civil penalties for any non-compliance with the Federal Power Act and the FERC's rules and orders.

Interstate Pipelines

The FERC has jurisdiction over the construction and operation of pipelines and related facilities used in the transportation, storage and sale of natural gas in interstate commerce, including the modification or abandonment of such facilities and rates, charges and terms and conditions of service for the transportation of natural gas in interstate commerce. The FERC was granted expanded market transparency authority under §23 of the NGA, a section added to the NGA by the Energy Policy Act of 2005. The FERC has adopted additional reporting and internet posting requirements for natural gas pipelines and buyers and sellers of natural gas, including revisions to the FERC Form No. 2 and the adoption of FERC Form 552, an annual report of aggregate volumes of gas sales and purchases at wholesale. The FERC has closed an inquiry into the methodology for rate recovery by natural gas pipelines of fuel and lost and unaccounted-for gas costs and while not taking any action, the FERC expressed its support for an amendment to the NGA that would provide it with the authority to order refunds in connection with its review of interstate pipeline transportation rates.

Rates established for our United States interstate natural gas transmission and storage operations at Northern Natural Gas and Kern River are also subject to the FERC's regulatory authority. The rates the FERC authorizes these companies to charge their customers may not be sufficient to cover the costs incurred to provide services in any given period. These pipelines, from time to time, have in effect rate settlements approved by the FERC which prevent them or third parties from modifying rates, except for allowed adjustments, for certain periods. These settlements do not preclude the FERC from initiating a separate proceeding under the NGA to modify the rates, as it did in November 2009 when it initiated a Section 5 proceeding to investigate the reasonableness of Northern Natural Gas' rates. It is not possible to determine at this time whether any additional such actions would be instituted or what the outcome of the ongoing proceeding or any other would be, but such proceedings could result in rate adjustments.

United Kingdom Electricity Distribution

Northern Electric and Yorkshire Electricity, as DNOs and holders of electricity distribution licenses, are subject to regulation by GEMA. Most of the revenue of a DNO is controlled by a distribution price control formula set out in the electricity distribution license. The price control formula does not directly constrain profits from year to year, but is a control on revenue that operates independently of most of the DNO's costs. It has been the practice of Ofgem to review and reset the formula at five-year intervals, although the formula has been, and may be, reviewed at other times at the discretion of Ofgem. The current five-year cost control period became effective on April 1, 2005 and is due to be replaced by a new formula effective April 1, 2010. A resetting of the formula requires the consent of the DNO; however, license modifications may be unilaterally imposed by Ofgem without such consent following review by the British competition commission. Northern Electric and Yorkshire Electricity have each agreed to Ofgem's proposals for the resetting of the formula commencing April 1, 2010. GEMA is able to impose financial penalties on DNOs that contravene any of their electricity distribution license duties or certain of their duties under British law, or fail to achieve satisfactory performance of individual standards prescribed by GEMA. Any penalty imposed must be reasonable and may not exceed 10% of the DNO's revenue. During the term of the price control, additional costs have a direct impact on the financial results of Northern Electric and Yorkshire Electricity.

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

Through our subsidiaries we are continuing to develop and construct new or expanded facilities. We expect that these subsidiaries 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, gas storage facilities, new or expanded pipeline systems, as well as the continued maintenance of the installed asset base.

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 regulated rates or market prices our subsidiaries are able to charge their 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, our subsidiaries depend upon both internal and external sources of liquidity to provide working capital and to fund capital requirements. If we do not provide needed funding to our subsidiaries and the subsidiaries are unable to obtain funding from external sources, they may need to postpone or cancel planned capital expenditures.

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

A significant decrease in demand for natural gas or electricity in the markets served by our subsidiaries' pipeline and gas distribution systems would significantly decrease our operating revenue and thereby adversely affect our business and consolidated financial results.

A sustained decrease in demand for natural gas or electricity in the markets served by our subsidiaries 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 or natural gas, including the significant adverse changes in the economy and credit markets in 2008 and 2009 that may continue into future periods;
- an increase in the market price of natural gas or electricity or a decrease in the price of other competing forms of energy;
- efforts by customers, legislators and regulators to reduce their 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 natural gas or the fuel source for electricity generation or that limit the use of natural gas or 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.

Our subsidiaries are subject to market risk, counterparty performance risk and other risks associated with wholesale energy markets.

In general, wholesale market risk is the risk of adverse fluctuations in the market price of wholesale electricity and fuel, including natural gas and coal, which is compounded by volumetric changes affecting the availability of or demand for electricity and fuel. Wholesale electricity prices may be influenced by several factors, such as the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric and wind-powered generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth and changes in technology. Volumetric changes are caused by unanticipated changes in generation availability or changes in customer loads due to the weather, electricity prices, the economy, regulations or customer behavior. The Utilities purchase electricity and fuel in the open market or pursuant to short-term or variable-priced contracts as part of their normal operating businesses. If market prices rise, especially in a time when larger than expected volumes must be purchased at market or short-term prices, PacifiCorp or MidAmerican Energy may incur significantly greater expense than anticipated. Likewise, if electricity market prices decline in a period when PacifiCorp or MidAmerican Energy is a net seller of electricity in the wholesale market, PacifiCorp or MidAmerican Energy will earn less revenue.

The Utilities are also exposed to risks related to performance of contractual obligations by wholesale suppliers, customers and other participants in organized RTO markets. Each utility relies 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 the utilities to incur additional expenses to meet customer needs. In addition, when these contracts terminate, the utilities may be unable to purchase the commodities on terms equivalent to the terms of current contracts.

The Utilities rely on wholesale customers to take delivery of the energy they have committed to purchase and to pay for the energy on a timely basis. Failure of customers to take delivery may require these subsidiaries 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 the

Utilities for energy needed to satisfy their customers' energy needs may exceed the amounts they receive through rates. If our wholesale customers are unable to pay us for energy or fulfill their obligations, there may be a significant adverse impact on our cash flows. If the strategy used to minimize these risk exposures is ineffective or if PacifiCorp's or MidAmerican Energy's wholesale customers' financial condition deteriorates as a result of recent economic conditions causing them to be unable to pay, significant losses could result.

Transactional activities of MidAmerican Energy and other participants in organized RTO markets are governed by credit policies specified in each respective RTO's governing tariff and related business practices. Credit policies of RTO's, which have been developed through extensive stakeholder participation, generally seek to minimize potential loss in the event of a market participant default without unnecessarily inhibiting access to the marketplace. In the event of a default by a RTO market participant on its market-related obligations, losses are allocated among all other market participants in proportion to each participant's share of overall market activity during the period of time the loss was incurred. Because of this, MidAmerican Energy has potential indirect exposure to every other market participant in the RTO markets where it actively participates, including MISO, PJM, and ERCOT.

The deterioration in the credit quality of certain wholesale suppliers and customers and other RTO market participants of the Utilities as a result of the adverse economic conditions experienced in 2008 and 2009 could have an adverse impact on their ability to perform their contractual obligations, which in turn could have an adverse impact on our consolidated financial results.

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

During 2008 and early 2009, the United States, the United Kingdom 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 who were able to find financing, and in other cases resulted in the unavailability of certain types of debt financing. In 2008 and 2009, the United States federal government enacted legislation in an attempt to stabilize the economy, increased the federal deposit insurance, invested billions of dollars in financial institutions and took other steps to infuse liquidity into the economy. The United States federal government Troubled Asset Relief Program ("TARP") and current accommodative monetary stance in the United States and most other industrialized countries have reduced liquidity concerns, relieved credit constraints and provided many financial institutions with the ability to strengthen their financial position. However, there is no certainty that the credit environment will improve and it is also possible that financial institutions may not be able to provide previously arranged funding under revolving credit facilities or other arrangements like those that we and our subsidiaries have established as potential sources of liquidity. It is also difficult to predict how the financial markets will react to the United States federal government's gradual withdrawal or removal of certain economic stimulus programs. Uncertainty in the credit markets may negatively impact our and our subsidiaries' ability to access funds on favorable terms or at all. If we or our subsidiaries 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, consolidated financial condition and results of operations.

Our subsidiaries are exposed to credit risk of counterparties with whom they do business, and the failure of their significant customers to perform under or to renew their contracts, or failure to obtain new customers for expanded capacity, could adversely affect our consolidated financial results.

Certain of our subsidiaries are dependent upon a relatively small number of customers for a significant portion of their revenue. For example:

- a significant portion of our pipeline subsidiaries' capacity is contracted under long-term arrangements, and our pipeline subsidiaries are dependent upon relatively few customers for a substantial portion of their revenue;
- The Utilities rely on their wholesale customers to fulfill their commitments and pay for energy delivered to them on a timely basis;
- our United Kingdom utility electricity distribution businesses are dependent upon a relatively small number of retail suppliers; and
- generally, a single power purchaser takes energy from each of our non-utility generating facilities.

Adverse economic conditions or other events affecting counterparties with whom our subsidiaries conduct business could impair the ability of these counterparties to pay for services or fulfill their contractual obligations, or cause them to delay or reduce such payments to our subsidiaries. Our subsidiaries depend on these counterparties to remit payments on a timely basis. Some suppliers and customers experienced deteriorating credit quality in 2008 and 2009, and we continue to monitor these parties to attempt to reduce the impact of any potential counterparty default. Any delay or default in payment or limitation on the subsidiaries to negotiate alternative arrangements could adversely affect our consolidated financial results.

If our subsidiaries are unable to renew, remarket, or find replacements for their long-term arrangements, our sales volumes and revenue would be exposed to reduction and increased volatility. For example, without the benefit of long-term transportation agreements, we cannot assure that our pipeline subsidiaries will be able to transport gas at efficient capacity levels. Similarly, without long-term power purchase agreements, we cannot assure that our unregulated power generators will be able to operate profitably. Failure to maintain existing long-term agreements or secure new long-term agreements could adversely affect our consolidated financial results.

The replacement of any existing long-term agreements depends on market conditions and other factors that may be beyond our subsidiaries' control.

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

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

Our subsidiaries have a multitude of long-term agreements of varying duration that are material to the operation of their businesses, such as power purchase, coal and gas supply and transportation contracts. The failure to maintain, renew or replace these agreements on similar terms and conditions could increase our exposure to changes in prices, thereby increasing the volatility of our consolidated financial results. For example, each of our electric utilities currently has contracts of varying durations for the supply and transportation of coal for much of their existing generation capacity, although PacifiCorp obtains some of its coal supply from mines owned or leased by it. When these contracts expire or if they are not honored, we may not be able to purchase or transport coal on terms as favorable as the current contracts. Changes in the cost of coal, natural gas, fuel oil and associated transportation costs and changes in the relationship between such costs and the market price of power will affect our consolidated financial results. Since the sales price we receive for power may not change at the same rate as our coal, natural gas, fuel oil and associated transportation costs, we may be unable to pass on the changes in these costs to our customers. In addition, the overall prices we charge our retail customers in some jurisdictions are capped and our fuel recovery mechanisms in other states are frozen for various periods of time or have been eliminated.

Our public utility subsidiaries' financial results may be adversely affected if they are unable to obtain adequate, reliable and affordable access to natural gas transportation and electricity transmission service.

Our public utility subsidiaries depend on natural gas transportation and electricity transmission facilities owned and operated by other utilities to transport electricity and natural gas to both wholesale and retail markets, as well as natural gas purchased to supply some of our subsidiaries' electric generating facilities. If adequate transportation and transmission is unavailable, our subsidiaries may be unable to purchase and sell and deliver products. A lack of availability could also hinder our subsidiaries from providing adequate or economical electricity or natural gas to their wholesale and retail electric and gas customers and could adversely affect their financial results.

The different regional power markets have varying and dynamic regulatory structures, which could affect our businesses' growth and performance. In addition, the independent system operators who oversee the transmission systems in regional power markets 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 the financial results of our utilities.

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

In most parts of the United States and other markets in which our subsidiaries operate, demand for electricity peaks during the hot summer months when irrigation and cooling needs are higher. Market prices for electric supply also generally peak at that time. In other areas, demand for electricity peaks during the winter. In addition, demand for gas and other fuels generally peaks during the winter when heating needs are higher. This is especially true in Northern Natural Gas' market area and MidAmerican Energy's retail gas business. Further, extreme weather conditions such as heat waves or winter storms could cause these seasonal fluctuations to be more pronounced. Periods of low rainfall or snowpack may also impact electric generation at PacifiCorp's hydroelectric generating facilities.

As a result, the overall financial results of our subsidiaries may fluctuate substantially on a seasonal and quarterly basis. We have historically sold less power, 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 power and could adversely affect our consolidated financial results. Furthermore, during or following periods of low rainfall or snowpack, PacifiCorp may obtain substantially less electricity from hydroelectric generating facilities and must purchase greater amounts of electricity from the wholesale market or from other sources at market prices. Additionally, the Utilities have added substantial wind-powered generation capacity, which is a climate dependent resource. The resulting variable production output that may at times affect the amount of energy available for sale or purchase. The extent of fluctuation in our consolidated financial results may change depending on a number of factors related to our subsidiaries' regulatory environment and contractual agreements, including their ability to recover power costs, the existence of revenue sharing provisions and terms of the power sale contracts.

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

The operation of complex electric and gas utility (including generation, transmission and distribution) systems, pipelines or power generating facilities 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 power generation equipment, compressors, pipelines, 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 subsidiaries' revenue or significantly increase their expenses, thereby reducing the availability of distributions to us. For example, if our subsidiaries cannot operate their electric or natural gas facilities at full capacity due to damage caused by a catastrophic event, their revenue could decrease and their 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. Any reduction of revenue for such reason, or any other reduction of our subsidiaries' revenue or increase in their 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 continued threat of terrorism since September 11, 2001 and the impact of military and other actions by the United States and its allies has led to increased political, economic and financial market instability and has subjected our subsidiaries' operations to increased risks. The United States government has issued warnings that energy assets, specifically pipeline, nuclear generation and other electric utility infrastructure are potential targets for terrorist organizations. Political, economic or financial market instability or damage to the operating assets of our subsidiaries, 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 natural gas and electric energy, increased security, repair or other costs that may materially adversely affect us and our subsidiaries 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 and the ability of our subsidiaries to raise capital.

The insurance industry changed in response to these events. As a result, insurance covering risks we and our subsidiaries typically insure against may decrease in scope and availability and we may elect to self-insure against many such risks. In addition, the available insurance may have higher deductibles, higher premiums and more restrictive policy terms.

MidAmerican Energy is subject to the unique risks associated with nuclear generation.

The ownership and operation of nuclear power plants, such as MidAmerican Energy's 25% ownership interest in the Quad Cities Station, involves certain risks. These risks include, among other items, mechanical or structural problems, inadequacy or lapses in maintenance protocols, the impairment of reactor operation and safety systems due to human error, the costs of storage, handling and disposal of nuclear materials, limitations on the amounts and types of insurance coverage commercially available, and uncertainties with respect to the technological and financial aspects of decommissioning nuclear facilities at the end of their useful lives. The prolonged unavailability of the Quad Cities Station could materially adversely affect MidAmerican Energy's financial results, particularly when the cost to produce power at the plant is significantly less than market wholesale power prices. The following are among the more significant of these risks:

- *Operational Risk* - Operations at any nuclear power plant could degrade to the point where the plant would have to be shut down. If such degradations were to occur, the process of identifying and correcting the causes of the operational downgrade to return the plant to operation could require significant time and expense, resulting in both lost revenue and increased fuel and purchased power expense to meet supply commitments. Rather than incurring substantial costs to restart the plant, the plant could be shut down. Furthermore, a shut-down or failure at any other nuclear plant could cause regulators to require a shut-down or reduced availability at the Quad Cities Station.

- *Regulatory Risk* - The NRC may modify, suspend or revoke licenses and impose civil penalties for failure to comply with the Atomic Energy Act applicable regulations or the terms of the licenses of nuclear facilities. Unless extended, the NRC operating licenses for the Quad Cities Station will expire in 2032. Changes in regulations by the NRC could require a substantial increase in capital expenditures or result in increased operating or decommissioning costs.

- *Nuclear Accident Risk* - Accidents and other unforeseen problems have occurred at nuclear facilities other than the Quad Cities Station, both in the United States and elsewhere. The consequences of an accident can be severe and include loss of life and property damage. Any resulting liability from a nuclear accident could exceed MidAmerican Energy's resources, including insurance coverage.

We own investments and projects located in foreign countries that are exposed to increased economic, regulatory and political risks.

We own and may acquire significant energy-related investments and projects outside of the United States. In addition to any disruption in the global financial markets, the economic, regulatory and political conditions in some of the countries where we have operations or are pursuing investment opportunities may present increased risks related to, among others, inflation, foreign currency exchange rate fluctuations, currency repatriation restrictions, nationalization, renegotiation, privatization, availability of financing on suitable terms, customer creditworthiness, construction delays, business interruption, political instability, civil unrest, guerilla activity, terrorism, expropriation, trade sanctions, contract nullification and changes in law, regulations or tax policy. We may not be capable of either fully insuring against or effectively hedging these risks.

We are exposed to risks related to fluctuations in currency rates.

Our business operations and investments outside the United States increase our risk related to fluctuations in currency rates, primarily the British pound. Our principal reporting currency is the United States dollar, and the value of the assets and liabilities, earnings, cash flows and potential distributions from our foreign operations changes with the fluctuations of the currency in which they transact. We may selectively reduce some foreign currency risk by, among other things, requiring contracted amounts be settled in United States dollars, indexing contracts to the United States dollar or hedging through foreign currency derivatives. These efforts, however, may not be effective and could negatively affect our consolidated financial results. We attempt, in many circumstances, to structure foreign transactions to provide for payments to be made in, or indexed to, United States dollars or a currency freely convertible into United States dollars. We may not be able to obtain sufficient dollars or other hard currency or available dollars may not be allocated to pay such obligations, which could adversely affect our consolidated financial results.

Cyclical fluctuations in the residential real estate brokerage and mortgage businesses could adversely affect HomeServices.

The residential real estate brokerage and mortgage industries tend to experience cycles of greater and lesser activity and profitability and are typically affected by changes in economic conditions, including the current downturn in the United States housing market, which are beyond HomeServices' control. Any of the following are examples of items that could have a material adverse effect on HomeServices' businesses by causing a general decline in the number of home sales, sale prices or the number of home financings which, in turn, would adversely affect its financial results:

- rising interest rates or unemployment rates, including the recent significant rise in unemployment in the United States which may continue into future periods;
- periods of economic slowdown or recession in the markets served, including the significant adverse changes in the economy in 2008 and 2009 that may continue into future periods;
- decreasing home affordability;
- lack of available mortgage credit for potential homebuyers, including the reduced availability of credit generally in 2008 and 2009 that may continue into future periods;
- declining demand for residential real estate as an investment;
- nontraditional sources of new competition; and
- changes in applicable tax law.

Poor performance of plan and fund investments and other factors impacting the pension and other postretirement benefit plans and nuclear decommissioning and mine reclamation trust funds could unfavorably impact our cash flows and liquidity.

Costs of providing our non-contributory defined benefit pension and other postretirement benefit plans 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 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. 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 nuclear decommissioning and mine reclamation are also 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 and our subsidiaries are involved in numerous legal proceedings, the outcomes of which are uncertain and could adversely affect our consolidated financial results.

We and our subsidiaries 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 and our subsidiaries 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 or our subsidiaries 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. In addition to legal proceedings to which we are party, it is possible that outcomes of GHG litigation involving others in our industry could impact our business through additional environmental regulatory requirements.

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

Not applicable.

Item 2. Properties

The Company's energy properties consist of the physical assets necessary to support its electricity and natural gas businesses. Properties of the Company's electricity businesses include electric generation, transmission and distribution facilities, as well as coal mining assets that support certain of the Company's electric generating facilities. Properties of the Company's natural gas businesses include natural gas distribution facilities, interstate pipelines, storage facilities, compressor stations and meter stations. In addition to these physical assets, the Company has rights-of-way, mineral rights and water rights that enable the Company to utilize its facilities. It is the opinion of the Company's management that the principal depreciable properties owned by the Company are in good operating condition and are well maintained. Pursuant to separate financing agreements, substantially all or most of the properties of each of the Company's subsidiaries (except CE Electric UK, MidAmerican Energy and Northern Natural Gas) are pledged or encumbered to support or otherwise provide the security for their own subsidiary debt. For additional information regarding the Company's energy properties, refer to Item 1 of this Form 10-K and Notes 3, 4 and 22 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

The following table summarizes the electric generation facilities of MEHC's subsidiaries as of December 31, 2009:

Energy Source	Entity	Location by Significance	Facility Net Capacity (MW)	Net MW Owned
Coal	PacifiCorp and MidAmerican Energy	Iowa, Wyoming, Utah, Arizona, Colorado and Montana	14,280	9,494
Natural gas and other	PacifiCorp, MidAmerican Energy and CalEnergy Generation-Domestic	Utah, Iowa, Illinois, Washington, Oregon, Texas, New York and Arizona	4,873	4,355
Wind	PacifiCorp and MidAmerican Energy	Iowa, Wyoming, Washington and Oregon	2,213	2,205
Hydroelectric	PacifiCorp, MidAmerican Energy, CalEnergy Generation-Foreign and CalEnergy Generation-Domestic	Washington, Oregon, The Philippines, Idaho, California, Utah, Hawaii, Montana, Illinois and Wyoming	1,321	1,294
Nuclear	MidAmerican Energy	Illinois	1,740	435
Geothermal	PacifiCorp and CalEnergy Generation-Domestic	California and Utah	361	198
		Total	24,788	17,981

The right to construct and operate the Company's electric transmission and distribution facilities and interstate natural gas pipelines across certain property was obtained in most circumstances through negotiations and, where necessary, through the exercise of the power of eminent domain. PacifiCorp, MidAmerican Energy, Northern Natural Gas and Kern River in the United States and Northern Electric and Yorkshire Electricity in the United Kingdom continue to have the power of eminent domain in each of the jurisdictions in which they operate their respective facilities, but the United States utilities do not have the power of eminent domain with respect to Native American tribal lands. Although the main Kern River pipeline crosses the Moapa Indian Reservation, all facilities in the Moapa Indian Reservation are located within a utility corridor that is reserved to the United States Department of Interior, Bureau of Land Management.

With respect to real property, each of the electric transmission and distribution facilities and interstate natural gas pipelines fall into two basic categories: (1) parcels that are owned in fee, such as certain of the electric generation stations, electric substations, natural gas compressor stations, natural gas meter stations and office sites; and (2) 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 electric transmission and distribution facilities and interstate natural gas pipelines. The Company believes that each of its energy subsidiaries has satisfactory title to all of the real property making up their respective facilities in all material respects.

Item 3. Legal Proceedings

The Company is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. The Company does not believe that such normal and routine litigation will have a material effect on its consolidated financial results. The Company 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.

PacifiCorp

In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in the federal district court in Cheyenne, Wyoming, alleging violations of the Wyoming state opacity standards at PacifiCorp's Jim Bridger generating facility in Wyoming. Under Wyoming state requirements, which are part of the Jim Bridger generating facility's Title V permit and are enforceable by private citizens under the federal Clean Air Act, a potential source of pollutants such as a coal-fired generating facility must meet minimum standards for opacity, which is a measurement of light that is obscured in the flue of a generating facility. The complaint alleged thousands of violations of asserted six-minute compliance periods and sought an injunction ordering the Jim Bridger generating facility's compliance with opacity limits, civil penalties of $32,500 per day per violation and the plaintiffs' costs of litigation. In August 2009, the court ruled on a number of summary judgment motions by which it determined that the plaintiffs have sufficient legal standing to proceed with their complaint and that all other issues raised in the summary judgment motions will be resolved at trial. In February 2010, PacifiCorp, the Sierra Club and the Wyoming Outdoor Council reached an agreement in principle to settle all outstanding claims in the action. The settlement will be memorialized in a consent decree to be filed with the EPA for review and also with the court for review and approval. If approved by the court as expected, the settlement is not expected to have a material impact on PacifiCorp's consolidated financial results.

CalEnergy Generation-Foreign

In February 2002, pursuant to the share ownership adjustment mechanism in the CE Casecnan shareholder agreement, MEHC's indirect wholly owned subsidiary, CE Casecnan Ltd., advised the minority shareholder of CE Casecnan, LaPrairie Group Contractors (International) Ltd. ("LPG") that MEHC's indirect ownership interest in CE Casecnan had increased to 100% effective from commencement of commercial operations. In July 2002, LPG filed a complaint in the Superior Court of the State of California, City and County of San Francisco against CE Casecnan Ltd. and MEHC. LPG's complaint, as amended, seeks compensatory and punitive damages arising out of CE Casecnan Ltd.'s and MEHC's alleged improper calculation of the proforma financial projections and alleged improper settlement of the NIA arbitration. In January 2006, the Superior Court of the State of California entered a judgment in favor of LPG against CE Casecnan Ltd. Pursuant to the judgment, 15% of the distributions of CE Casecnan were deposited into escrow plus interest at 9% per annum. The judgment was appealed, and as a result of the appellate decision, CE Casecnan Ltd. determined that LPG would retain ownership of 10% of the shares of CE Casecnan, with the remaining 5% share to be transferred to CE Casecnan Ltd. subject to certain buy-up rights under the shareholder agreement. The issues relating to the exercise of the buy-up right have been decided by the court and in June 2009, LPG exercised its buy-up rights with respect to the remaining 5% ownership interest. In October 2009, the court issued a Final Judgment declaring that after the buy up LPG was a 15% shareholder. The Final Judgment was appealed on January 13, 2010 in the Superior Court of the State of California, City and County of San Francisco. On appeal, CE Casecnan Ltd. will argue that LPG is only entitled to a 10% interest in the project company, and will challenge the computation of the buy-up price for the still disputed 5% interest.

In July 2005, MEHC and CE Casecnan Ltd. commenced an action against San Lorenzo Ruiz Builders and Developers Group, Inc. ("San Lorenzo") in the District Court of Douglas County, Nebraska, seeking a declaratory judgment as to San Lorenzo's right to repurchase up to 15% of the shares in CE Casecnan. In January 2006, San Lorenzo filed a counterclaim against MEHC and CE Casecnan Ltd. seeking declaratory relief that it has effectively exercised its option to purchase up to15% of the shares of CE Casecnan, that it is the rightful owner of such shares and that it is due all dividends paid on such shares. The parties have completed discovery and a trial has been set to begin in March 2010. The impact, if any, of this litigation on the Company cannot be determined at this time. The Company intends to vigorously defend the counterclaims.

Item 4. Reserved

PART II

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

MEHC's common stock is owned by Berkshire Hathaway, Mr. Walter Scott, Jr. and certain of his family members and family controlled trusts and corporations, and Mr. Gregory E. Abel, its President and Chief Executive Officer, and has not been registered with the SEC pursuant to the Securities Act of 1933, as amended, listed on a stock exchange or otherwise publicly held or traded. MEHC has not declared or paid any cash dividends on its common stock during the last two fiscal years and does not presently anticipate that it will declare any dividends on its common stock in the foreseeable future.

For a discussion of regulatory restrictions that limit PacifiCorp's and MidAmerican Energy's ability to pay dividends on their common stock to MEHC, refer to Note 17 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Item 6. Selected Financial Data

The following table sets forth the Company's selected consolidated historical financial data, which should be read in conjunction with the information in Item 7 of this Form 10-K and with the Company'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 the Company's audited historical Consolidated Financial Statements and notes thereto (in millions).

	Years Ended December 31,				
	2009	**2008**	**2007**	**2006(1)**	**2005**
Consolidated Statement of Operations Data:					
Operating revenue	$ 11,204	$ 12,668	$ 12,376	$ 10,301	$ 7,116
Net income(2)	1,188	1,871	1,219	943	578
Net income attributable to noncontrolling interests	31	21	30	27	15
Net income attributable to MEHC(2)	1,157	1,850	1,189	916	563

	As of December 31,				
	2009	**2008**	**2007**	**2006(1)**	**2005**
Consolidated Balance Sheet Data:					
Total assets	$ 44,684	$ 41,441	$ 39,216	$ 36,447	$ 20,371
Short-term debt	179	836	130	552	70
Long-term debt, including current maturities:					
MEHC senior debt	5,371	5,121	5,471	4,479	2,776
MEHC subordinated debt	590	1,321	1,125	1,357	1,588
Subsidiary debt	13,791	12,954	13,097	11,614	7,150
Total MEHC shareholders' equity	12,576	10,207	9,326	8,011	3,385
Noncontrolling interests	267	270	256	242	110

(1) Reflects the acquisition of PacifiCorp on March 21, 2006.

(2) Reflects the $646 million after-tax gain recognized on the termination of the Constellation Energy Group, Inc. ("Constellation Energy") merger agreement on December 17, 2008.

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 the Company 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 the Company's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. The Company's actual results in the future could differ significantly from the historical results.

Results of Operations

Overview

Net income attributable to MEHC for 2009 was $1.157 billion, a decrease of $693 million, or 37%, compared to 2008. The results for 2008 included a $646 million after-tax gain recognized on the termination of the Constellation Energy merger agreement in 2008. The results for 2009 included an after-tax stock-based compensation charge of $75 million as a result of the purchase of shares of common stock that were issued upon the exercise of stock options and an after-tax gain on the Constellation Energy common stock investment of $22 million. Excluding the impact of these items, net income attributable to MEHC increased $6 million for 2009 compared to 2008. Net income attributable to MEHC increased due to higher net income at PacifiCorp, MidAmerican Funding, CalEnergy Generation-Foreign and HomeServices and lower United States income taxes on foreign earnings, partially offset by lower net income at Northern Natural Gas, Kern River and CE Electric UK.

Net income was higher at PacifiCorp as a result of lower energy costs, higher rates approved by regulators, the sale of renewable energy credits and a lower effective income tax rate, partially offset by lower average wholesale prices and retail volumes, higher depreciation and amortization, higher operating expenses and higher interest expense. MidAmerican Funding's net income increased due to a lower effective income tax rate, which included income tax benefits of $55 million for repairs deductions, partially offset by lower operating income. MidAmerican Funding's operating income was lower due to lower regulated electric margins and higher depreciation and amortization, partially offset by lower maintenance costs as a result of the storm and flood damage in 2008. Net income was higher at CalEnergy Generation-Foreign due to higher rainfall and related revenue earned at the Casecnan project and at HomeServices due to lower office closure costs and other operating expenses.

Net income at Northern Natural Gas and Kern River was lower as a result of less favorable market conditions, $30 million of after-tax gains on the sale of certain non-strategic operating assets at Northern Natural Gas in 2008 and a lower customer refund liability in 2008 related to Kern River's 2004 rate case of $26 million. Net income was lower at CE Electric UK due primarily to a stronger United States dollar that reduced net income $33 million, lower distribution revenue and a $15 million impairment of the certain Australian hydrocarbon exploration and development assets recognized in 2009.

Net income attributable to MEHC for 2008 was $1.85 billion, an increase of $661 million, or 56%, compared to 2007, which included the after-tax gain of $646 million recognized on the termination of the Constellation Energy merger agreement in 2008. Excluding the $646 million, net income attributable to MEHC increased $15 million, or 1%, from the comparable period in 2007. Net income attributable to MEHC was impacted by favorable operating results at Northern Natural Gas, MidAmerican Energy and PacifiCorp, $30 million of after-tax gains on the sale of non-strategic assets at Northern Natural Gas and favorable changes in Kern River's current rate proceeding estimate. Net income attributable to MEHC was unfavorably impacted by lower earnings at HomeServices due to the continuing weak United States housing market and at Kern River due to lower revenue from less favorable market conditions. Net income attributable to MEHC was also lower in 2008 compared to 2007 due to the impact of the foreign currency exchange rate of $25 million, the transfer of two geothermal projects to the Philippine government in July 2007, a $58 million deferred income tax benefit recognized in 2007 as a result of the reduction in the United Kingdom corporate income tax rate from 30% to 28% and higher United States income taxes on foreign earnings in 2008.

Segment Results

The reportable segment financial information includes all necessary adjustments and eliminations needed to conform to the Company's significant accounting policies. The differences between the segment amounts and the consolidated amounts, described as "Corporate/other," relate principally to corporate functions, including administrative costs and intersegment eliminations.

Operating revenue and operating income for the Company's reportable segments for the years ended December 31 are summarized as follows (in millions):

	2009	2008	Change		2008	2007	Change	
Operating revenue:								
PacifiCorp	$ 4,457	$ 4,498	$ (41)	(1)%	$ 4,498	$ 4,258	$ 240	6%
MidAmerican Funding	3,699	4,715	(1,016)	(22)	4,715	4,267	448	10
Northern Natural Gas	689	769	(80)	(10)	769	664	105	16
Kern River	372	443	(71)	(16)	443	404	39	10
CE Electric UK	825	993	(168)	(17)	993	1,079	(86)	(8)
CalEnergy Generation-Foreign	147	138	9	7	138	220	(82)	(37)
CalEnergy Generation-Domestic	31	30	1	3	30	32	(2)	(6)
HomeServices	1,037	1,133	(96)	(8)	1,133	1,500	(367)	(24)
Corporate/other	(53)	(51)	(2)	(4)	(51)	(48)	(3)	(6)
Total operating revenue	$11,204	$12,668	$(1,464)	(12)	$12,668	$12,376	$ 292	2
Operating income:								
PacifiCorp	$ 1,079	$ 952	$ 127	13%	$ 952	$ 917	$ 35	4%
MidAmerican Funding	469	590	(121)	(21)	590	514	76	15
Northern Natural Gas	337	457	(120)	(26)	457	308	149	48
Kern River	221	305	(84)	(28)	305	277	28	10
CE Electric UK	394	514	(120)	(23)	514	555	(41)	(7)
CalEnergy Generation-Foreign	113	103	10	10	103	142	(39)	(27)
CalEnergy Generation-Domestic	15	15	-	-	15	12	3	25
HomeServices	11	(58)	69	119	(58)	33	(91)	*
Corporate/other	(174)	(50)	(124)	*	(50)	(70)	20	29
Total operating income	$ 2,465	$ 2,828	$ (363)	(13)	$ 2,828	$ 2,688	$ 140	5

* Not meaningful

PacifiCorp

Operating revenue decreased $41 million for 2009 compared to 2008 due to a decrease in wholesale and other revenue of $154 million, partially offset by higher retail revenue of $69 million and the sale of renewable energy credits totaling $44 million. The decrease in wholesale and other revenue was due primarily to a 24% decrease in average wholesale prices, partially offset by higher revenue attributable to PacifiCorp's majority owned coal mining operation. The increase in retail revenue was due to higher prices approved by regulators totaling $134 million, partially offset by a 3% decrease in retail volumes. The decrease in retail volumes was principally related to lower average customer usage due to the effect of current economic conditions mainly on industrial customers throughout PacifiCorp's service territory and residential customers in Oregon, partially offset by growth in the average number of commercial and residential customers primarily in Utah. Total retail and wholesale sales volumes decreased 2%.

Operating income increased $127 million for 2009 compared to 2008 due to lower energy costs of $305 million, partially offset by the lower operating revenue, higher depreciation and amortization of $68 million due to the addition of new generating facilities and higher operating expenses of $69 million. Energy costs were lower due largely to a 35% decrease in the average cost of purchased electricity on a 4% decrease in the volume of purchased electricity, partially offset by the effects of regulatory cost recovery adjustment mechanisms of $26 million. The addition of the Chehalis natural gas-fired generating facility and new wind-powered generating facilities in the second half of 2008 and during 2009, along with the 2% decrease in overall sales volumes, allowed PacifiCorp to reduce its need for purchased electricity. Operating expenses increased due to higher costs attributable to PacifiCorp's majority owned coal mining operation, higher DSM costs, which are recovered in rates, and increased property taxes driven by increased levels of assessable property.

Operating revenue increased $240 million for 2008 compared to 2007. Retail revenue increased $198 million due to higher prices approved by regulators of $129 million and higher retail volumes of 2% due to growth in the average number of residential and commercial customers and higher average customer usage totaling $69 million. Wholesale and other revenue increased $42 million due to higher average wholesale prices, partially offset by lower wholesale volumes, and higher contract prices for transmission services. Overall, sales volumes were relatively flat for 2008 compared to 2007.

Operating income increased $35 million for 2008 compared to 2007. The higher operating revenue and lower depreciation and amortization of $6 million were partially offset by higher energy costs of $197 million and operating expenses of $14 million. Depreciation and amortization decreased due to a 2008 depreciation study, substantially offset by new generation placed in service. Energy costs increased due to higher average prices for both natural gas and coal totaling $180 million, higher transmission and other costs of $15 million due to new transmission contracts and unfavorable changes in the fair value of energy purchase contracts accounted for as derivatives of $7 million, partially offset by lower purchased electricity of $5 million. Purchased electricity decreased due to lower volumes resulting from the addition of the Lake Side plant in 2007, the Chehalis plant acquired in 2008 and other sources of owned generation, which was largely offset by the higher average cost of purchased electricity. Operating expenses increased due to higher levels of assessable property from new owned generation placed in service and higher DSM costs, which are recovered in rates.

MidAmerican Funding

MidAmerican Funding's operating revenue and operating income for the years ended December 31 are summarized as follows (in millions):

	2009	2008	Change		2008	2007	Change	
Operating revenue:								
Regulated electric	$ 1,715	$ 2,030	$ (315)	(16)%	$ 2,030	$ 1,934	$ 96	5%
Regulated natural gas	857	1,377	(520)	(38)	1,377	1,174	203	17
Nonregulated and other	1,127	1,308	(181)	(14)	1,308	1,159	149	13
Total operating revenue	$ 3,699	$ 4,715	$(1,016)	(22)	$ 4,715	$ 4,267	$ 448	10
Operating income:								
Regulated electric	$ 331	$ 470	$ (139)	(30)%	$ 470	$ 398	$ 72	18%
Regulated natural gas	70	66	4	6	66	53	13	25
Nonregulated and other	68	54	14	26	54	63	(9)	(14)
Total operating income	$ 469	$ 590	$ (121)	(21)	$ 590	$ 514	$ 76	15

Regulated electric operating revenue decreased $315 million for 2009 compared to 2008. Wholesale and other revenue decreased $288 million due to a 35% decrease in average wholesale prices and an 11% decrease in volumes resulting from reduced demand for electricity due to the current economic conditions and mild temperatures. Retail revenue decreased $27 million on 4% lower volumes due primarily to reduced industrial demand and mild temperatures experienced throughout the service territory in 2009. Total retail and wholesale sales volumes decreased by 7%.

Regulated electric operating income decreased $139 million for 2009 compared to 2008. The lower revenue was partially offset by a decrease in the cost of energy of $222 million as a result of lower purchased electricity of $176 million and a lower cost of natural gas of $54 million, which were both due to lower average costs and volumes. The addition of new wind-powered generating facilities in 2008 allowed MidAmerican Energy to replace more expensive sources of electricity. Depreciation and amortization increased $53 million due primarily to the addition of new wind-powered generating facilities. Operating expenses decreased $7 million due largely to lower maintenance costs as a result of the storm and flood damage in 2008, partially offset by higher DSM costs, which are recovered in rates.

Regulated natural gas operating revenue decreased $520 million for 2009 compared to 2008 due primarily to a reduction in the average per-unit cost of gas sold, which was passed on to customers and resulted in lower cost of sales, and lower sales volumes of 5% as a result of fewer wholesale market opportunities due to lower price spreads and mild weather experienced throughout the service territory in 2009. Regulated natural gas operating income increased $4 million for 2009 compared to 2008, due primarily to lower operating expenses.

Nonregulated and other operating revenue decreased $181 million for 2009 compared to 2008 due to lower gas revenue of $244 million on a 47% decrease in average prices and a 13% decrease in volumes, partially offset by higher electric retail revenue on a 10% increase in volumes. Nonregulated and other operating income increased $14 million for 2009 compared to 2008 due primarily to higher margins on electric retail sales.

Regulated electric revenue increased $96 million for 2008 compared to 2007. Wholesale revenue increased $101 million due to a 20% increase in volumes resulting from increased generation available from the addition of owned generation and scheduled outages in 2007, partially offset by lower average wholesale prices. Retail revenue decreased $6 million due to lower sales volumes to residential customers resulting from the mild temperatures experienced in the service territory during the 2008 cooling season, partially offset by an increase in the average number of retail customers. Total sales volumes increased 7% for 2008 compared to 2007.

Regulated electric operating income increased $72 million for 2008 compared to 2007 due to higher wholesale volumes resulting from the availability of lower-cost base load generation and a lower average price for purchased power, partially offset by an increase in depreciation and amortization as a result of Walter Scott Energy Center Unit 4 being placed in service in June 2007 and new wind-powered generating facilities being placed in service during 2007 and 2008, partially offset by a decrease in regulatory expense related to revenue sharing in connection with the lower Iowa electric equity returns and higher maintenance costs.

Regulated natural gas revenue increased $203 million for 2008 compared to 2007 due primarily to a higher average per-unit cost of gas sold, which was passed on to customers and resulted in lower cost of sales, and higher retail sales volumes of 12% as a result of colder temperatures, partially offset by lower wholesale sales volumes. Regulated natural gas operating income increased $13 million due to the higher retail sales volumes.

Nonregulated and other revenue increased $149 million for 2008 compared to 2007 due primarily to higher gas revenue as a result of higher average prices and a 9% increase in volumes. Nonregulated and other operating income decreased $9 million due primarily to lower margins on electric retail sales due to higher average prices and a 7% decrease in volumes.

Northern Natural Gas

Operating revenue decreased $80 million for 2009 compared to 2008 due to lower transportation revenue of $70 million and lower sales of gas for operational purposes due primarily to lower prices. Transportation revenue decreased due to lower volumes caused by less favorable economic conditions, lower natural gas price spreads and the sale of the Beaver system in 2008. Operating income decreased $120 million for 2009 compared to 2008 due to the lower transportation revenue and pre-tax gains on the sale of certain non-strategic operating assets of $50 million in 2008.

Operating revenue increased $105 million for 2008 compared to 2007 due primarily to higher transportation revenue of $88 million, due to stronger market conditions and the additional capacity available as a result of the Northern Lights expansion project, and higher storage revenue of $12 million, due to an expansion of its Redfield storage facilities and higher interruptible storage activity. Operating income increased $149 million for 2008 compared to 2007 due to the higher transportation and storage revenues and pre-tax gains on the sale of certain non-strategic operating assets of $50 million in 2008.

Kern River

Operating revenue decreased $71 million for 2009 compared to 2008 due to lower price spreads and changes in Kern River's customer refund liability related to the 2004 rate case, which resulted in lower revenue of $33 million. Operating income decreased $84 million for 2009 compared to 2008 due to the lower revenue and higher depreciation and amortization expense of $15 million.

Operating revenue increased $39 million for 2008 compared to 2007 due to decreases in Kern River's customer refund liability related to the 2004 rate case, which resulted in higher revenue of $55 million, partially offset by $20 million of lower revenue as a result of strong market conditions in 2007. Operating income increased $28 million for 2008 compared to 2007 due to the higher revenue, partially offset by a $6 million sales and use tax refund received in 2007 and higher depreciation.

CE Electric UK

Operating revenue decreased $168 million for 2009 compared to 2008 due to the impact from the foreign currency exchange rate totaling $150 million, lower distribution revenue of $10 million and lower contracting revenue of $8 million. Distribution revenue decreased due to over-recovery provisions in the current regulatory period totaling $16 million and lower units distributed, partially offset by higher tariff rates. Operating income decreased $120 million for 2009 compared to 2008 due to the impact from the foreign currency exchange rate on operating income totaling $73 million, a $20 million impairment of certain Australian hydrocarbon exploration and development assets, higher depreciation and amortization of $14 million and the lower distribution revenue.

Operating revenue decreased $86 million for 2008 compared to 2007 due to the impact of the foreign currency exchange rate of $83 million and lower contracting activity of $22 million, partially offset by higher distribution revenue of $11 million and higher gas production at CE Gas of $8 million. Operating income decreased $41 million for 2008 compared to 2007 due primarily to the impact of the foreign currency exchange rate. A non-recurring gain of $17 million realized in 2007 on the sale of certain CE Gas assets was mostly offset by higher gross margins on distribution and gas production revenues in 2008.

CalEnergy Generation-Foreign

Operating revenue increased $9 million and operating income increased $10 million for 2009 compared to 2008 due to higher rainfall and related variable water delivery fees earned in 2009 at the Casecnan project, partially offset by lower prices received on variable energy.

Operating revenue decreased $82 million for 2008 compared to 2007 due to the transfer of the Malitbog and Mahanagdong projects on July 25, 2007 to the Philippine government, which reduced operating revenue by $95 million, partially offset by higher operating revenue of $13 million at the Casecnan project principally on higher variable energy fees earned on increased generation from higher water flows. Operating income decreased $39 million for 2008 compared to 2007 due to the lower revenue, partially offset by lower operating expense of $13 million and lower depreciation and amortization of $30 million as the projects were transferred.

HomeServices

Operating revenue decreased $96 million for 2009 compared to 2008 due to declines in average home sale prices of 10% and transaction volumes of 1%. Lower mortgage and brokerage activity during the first nine months of 2009 was mostly offset by higher activity in the fourth quarter in part due to the $8,000 new homebuyer credit. Operating income increased $69 million for 2009 compared to 2008 due to lower commissions, $30 million of higher office closure charges taken in 2008 and lower other operating expenses, partially offset by the lower revenue.

Operating revenue decreased $367 million for 2008 compared to 2007. Transaction volumes declined by 20% and average home sales prices declined by 8% reflecting the continuing weak United States housing market. HomeServices had an operating loss of $58 million in 2008, a $91 million decrease compared to 2007 due to the lower revenue and $39 million of expenses taken in 2008 related to office closures, partially offset by lower commissions and operating expenses.

Corporate/other

Operating income decreased $124 million for 2009 compared to 2008 due to $125 million of stock-based compensation expense as a result of the purchase of common stock issued by MEHC upon the exercise of the last remaining stock options that had been granted to certain members of management at the time of Berkshire Hathaway's acquisition of MEHC in 2000.

Consolidated Other Income and Expense Items

Interest Expense

Interest expense for the years ended December 31 is summarized as follows (in millions):

	2009	2008	Change		2008	2007	Change	
Subsidiary debt	$ 864	$ 850	$ 14	2%	$ 850	$ 858	$ (8)	(1)%
MEHC senior debt and other	331	348	(17)	(5)	348	326	22	7
MEHC subordinated debt-Berkshire Hathaway	58	111	(53)	(48)	111	108	3	3
MEHC subordinated debt-other	22	24	(2)	(8)	24	28	(4)	(14)
Total interest expense	$1,275	$1,333	$ (58)	(4)	$1,333	$1,320	$ 13	1

Interest expense decreased $58 million for 2009 compared to 2008 due to the repayment of $1 billion of 11% mandatory redeemable preferred securities to affiliates of Berkshire Hathaway that were issued in connection with the purchase of the Constellation Energy 8% preferred stock, debt retirements, scheduled principal repayments and the impact of the foreign currency exchange rate of $28 million, partially offset by debt issuances in 2009 at PacifiCorp and MEHC and in 2008 at PacifiCorp, MidAmerican Funding and Northern Natural Gas.

Interest expense increased $13 million for 2008 compared to 2007 due to debt issuances at domestic energy businesses and at MEHC, including the issuance of $1 billion of 11% mandatory redeemable preferred securities to affiliates of Berkshire Hathaway in September 2008 in connection with the purchase of the Constellation Energy 8% preferred stock, partially offset by the impact of the foreign currency exchange rate of $17 million, debt retirements and scheduled principal repayments.

Capitalized Interest

Capitalized interest decreased $13 million for 2009 compared to 2008 due to lower construction activity at MidAmerican Funding.

Interest and Dividend Income

Interest and dividend income decreased $37 million for 2009 compared to 2008 due to dividends received in 2008 related to the investment in the Constellation Energy 8% preferred stock and less favorable cash positions and lower rates in 2009.

Interest and dividend income decreased $30 million for 2008 compared to 2007 due to the maturities of guaranteed investment contracts in December 2007 and February 2008 that were used to retire debt maturing at CE Electric UK and lower average cash balances and interest rates, partially offset by dividends received from the Constellation Energy 8% preferred stock.

Other, net

Other, net decreased $1.042 billion for 2009 compared to 2008 due primarily to the 2008 termination of the merger agreement with Constellation Energy, which resulted in the receipt of a $175 million termination fee and the conversion of the Constellation Energy 8% preferred stock into $418 million of cash and 19.9 million shares of Constellation Energy common stock valued at $499 million. In 2009, the Company recognized pre-tax gains on the Constellation Energy common stock investment totaling $37 million. Other, net increased $1.076 billion for 2008 compared to 2007 due to the termination of the merger agreement with Constellation Energy.

Income Tax Expense

Income tax expense decreased $700 million for 2009 compared to 2008. The effective tax rates were 20% and 35% for 2009 and 2008, respectively. The decrease in income tax expense and the effective tax rate were due to lower pre-tax income, income tax benefits recognized in 2009 totaling $55 million for a change in tax accounting method for repairs deductions and the related regulatory treatment in Iowa, which requires immediate income recognition of such temporary differences, additional PTCs, lower United States income taxes on foreign earnings and the effects of ratemaking.

Income tax expense increased $526 million for 2008 compared to 2007. The effective tax rates were 35% and 28% for 2008 and 2007, respectively. The increases in income tax expense and the effective tax rate were due to higher pre-tax income, the recognition of $58 million of deferred income tax benefits in 2007 due to a reduction in the United Kingdom corporate income tax rate from 30% to 28% and higher United States income taxes on foreign earnings, partially offset by the benefit of additional PTCs.

Equity Income

Equity income increased $14 million for 2009 compared to 2008 due primarily to higher equity earnings at HomeServices related to refinance activity in its mortgage business. Equity income increased $5 million for 2008 compared to 2007 due primarily to the sale and write-off of an investment in a mortgage joint venture at HomeServices in 2007.

Net Income Attributable to Noncontrolling Interests

Net income attributable to noncontrolling interests increased $10 million for 2009 compared to 2008 due mainly to higher earnings attributable to PacifiCorp's majority owned coal mining operations. Net income attributable to noncontrolling interests decreased $9 million for 2008 compared to 2007 due to additional expense in 2007 related to the minority ownership of the Casecnan project.

Liquidity and Capital Resources

Each of MEHC's direct and indirect subsidiaries is organized as a legal entity separate and apart from MEHC and its other subsidiaries. Pursuant to separate financing agreements, the assets of each subsidiary may be pledged or encumbered to support or otherwise provide the security for its own subsidiary debt. It should not be assumed that any asset of any subsidiary of MEHC's will be available to satisfy the obligations of MEHC or any of its other subsidiaries' obligations. However, unrestricted cash or other assets which are available for distribution may, subject to applicable law, regulatory commitments and the terms of financing and ring-fencing arrangements for such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to MEHC or affiliates thereof. Refer to Note 17 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding the limitation of distributions from MEHC's subsidiaries.

As of December 31, 2009, the Company's total net liquidity available was $6.175 billion. The components of total net liquidity available are as follows (in millions):

	MEHC	PacifiCorp	MidAmerican Funding	Other Reporting Segments	Total[1]
Cash and cash equivalents	$ 17	$ 117	$ 88	$ 207	$ 429
Available revolving credit facilities	$ 585	$ 1,395	$ 654	$ 286	$ 2,920
Less:					
Short-term borrowings and issuances of commercial paper	(50)	-	-	(129)	(179)
Tax-exempt bond support, letters of credit and other	(42)	(258)	(195)	-	(495)
Net revolving credit facilities available	$ 493	$ 1,137	$ 459	$ 157	$ 2,246
Net liquidity available before Berkshire Equity Commitment	$ 510	$ 1,254	$ 547	$ 364	$ 2,675
Berkshire Equity Commitment[2]	3,500				3,500
Total net liquidity available	$ 4,010				$ 6,175
Unsecured revolving credit facilities:					
Maturity date[3]	2013	2012-2013	2010, 2013	2010	
Largest single bank commitment as a % of total[4]	17%	15%	23%	28%	

(1) The above table does not include unused revolving credit facilities and letters of credit for investments that are accounted for under the equity method.

(2) On March 1, 2006, MEHC and Berkshire Hathaway entered into the 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 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. The Berkshire Equity Commitment expires on February 28, 2011.

(3) MidAmerican Funding has two revolving credit facilities that renew annually for $5 million and $4 million and has a $645 million revolving credit facility that matures in 2013. For further discussion regarding the Company's credit facilities, refer to Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

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

The Company's cash and cash equivalents were $429 million as of December 31, 2009, compared to $280 million as of December 31, 2008. The Company has restricted cash and investments totaling $434 million and $395 million as of December 31, 2009 and 2008, respectively, related to (a) the Company's debt service reserve requirements for certain projects, (b) funds held in trust for nuclear decommissioning and coal mine reclamation and (c) unpaid dividends declared obligations. The debt service funds are restricted by their respective project debt agreements to be used only for the related project.

Operating Activities

Net cash flows from operating activities for 2009 and 2008 were $3.572 billion and $2.587 billion, respectively. Operating cash flows for 2009 include $128 million of net cash flows related to the Constellation Energy transaction, which is comprised of $536 million of proceeds received from the sale of Constellation Energy common stock and $408 million of income tax paid on gains recognized on the termination of the Constellation Energy merger agreement in December 2008 and the sale of stock in 2009. Operating cash flows for 2008 include a termination fee of $175 million received from Constellation Energy. The remaining increase in operating cash flows was due to higher income tax receipts, changes in collateral posted for derivative contracts of $201 million, lower customer refunds related to the Kern River rate case in 2008 of $179 million and working capital, partially offset by the impact from the foreign currency exchange rate. Income tax receipts were higher due primarily to lower pre-tax income, the increased tax deductions on capital projects and additional PTCs.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2009 and 2008 were $(2.669) billion and $(4.344) billion, respectively. In February 2008, the Company received proceeds from the maturity of a guaranteed investment contract of $393 million. In September 2008, the Company made a $1.0 billion investment in Constellation Energy's 8% preferred stock and acquired Chehalis Power Generation, LLC for $308 million. In December 2008, MEHC and Constellation Energy entered into a termination agreement, which resulted in, among other things, the conversion of the $1.0 billion investment in Constellation Energy's 8% preferred stock into $1.0 billion of 14% Senior Notes due from Constellation Energy, 19.9 million shares of Constellation Energy common stock and cash totaling $418 million. In January 2009, the Company received $1.0 billion, plus accrued interest, in full satisfaction of the 14% Senior Notes from Constellation Energy. In July 2009, the Company purchased 225 million shares, representing approximately a 10% interest, of BYD Company Limited ("BYD") common stock for $232 million. Capital expenditures decreased $524 million due primarily to lower capital expenditures in 2009 associated with the construction of wind-powered generating facilities at MidAmerican Funding, partially offset by higher capital expenditures at PacifiCorp associated with wind-powered generating facilities, including payments for wind-powered facilities placed in-service in December 2008, and transmission system investment.

Capital Expenditures

Capital expenditures by reportable segment for the years ended December 31 are summarized as follows (in millions):

	2009	2008
Capital expenditures(1):		
PacifiCorp	$ 2,328	$ 1,789
MidAmerican Funding	439	1,473
Northern Natural Gas	177	196
CE Electric UK	387	440
Other	82	39
Total capital expenditures	$ 3,413	$ 3,937

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

The Company's capital expenditures relate primarily to the Utilities, which consisted mainly of the following for the years ended December 31:

2009:

- Transmission system investment totaling $764 million, including a major segment of the Energy Gateway Transmission Expansion Program at PacifiCorp.
- The development and construction of wind-powered generating facilities totaling $438 million. During 2009, PacifiCorp placed in service 265.5 MW of wind-powered generating facilities.
- Emissions control equipment totaling $364 million.
- Distribution, generation, mining and other infrastructure needed to serve existing and expected growing demand totaling $1.201 billion.

2008:

- The development and construction of wind-powered generating facilities totaling $1.630 billion.
- Emissions control equipment totaling $277 million.
- Transmission system investment totaling $274 million.
- Distribution, generation, mining and other infrastructure needed to serve existing and expected growing demand totaling $1.081 billion.

Financing Activities

Net cash flows from financing activities for the year ended December 31, 2009 were $(758) million. Uses of cash totaled $2.0 billion and consisted mainly of repayments of MEHC senior and subordinated debt totaling $734 million, the net repayments of subsidiary short-term debt totaling $498 million, repayments of subsidiary debt totaling $444 million, the net repayments of MEHC's revolving credit facility totaling $166 million and net purchases of common stock of $123 million. Sources of cash totaled $1.242 billion and consisted mainly of proceeds from the issuance of subsidiary debt totaling $992 million and proceeds from the issuance of MEHC senior debt totaling $250 million.

Net cash flows from financing activities for the year ended December 31, 2008 were $866 million. Sources of cash totaled $3.872 billion and consisted mainly of proceeds from the issuance of MEHC senior and subordinated debt totaling $1.649 billion, proceeds from the issuance of subsidiary debt totaling $1.498 billion, the net proceeds from subsidiary short-term debt totaling $509 million and the net proceeds from MEHC's revolving credit facility totaling $216 million. Uses of cash totaled $3.006 billion and consisted mainly of repayments of MEHC senior and subordinated debt totaling $1.803 billion, repayments of subsidiary debt totaling $1.077 billion and a $99 million payment of hedging instruments related to the maturity of United States dollar denominated debt at CE Electric UK.

Short-term Debt and Revolving Credit Facilities

MEHC had outstanding borrowings of $50 million under its unsecured revolving credit facilities as of December 31, 2009 and $216 million outstanding borrowings as of December 31, 2008. Borrowings by MEHC's subsidiaries under their commercial paper programs and unsecured revolving credit facilities decreased $491 million during 2009 due mainly to decreases at PacifiCorp and MidAmerican Funding. PacifiCorp's short-term debt decreased $85 million due to the issuance of long-term debt and capital contributions from MEHC, partially offset by capital expenditures and maturities of long-term debt in excess of net cash provided by operating activities. MidAmerican Funding's short-term debt decreased $457 million due to improvements in operating cash flows and lower capital expenditures. Any disruptions in the credit markets may result in increased costs of commercial paper and limit the ability of PacifiCorp and MidAmerican Funding to issue commercial paper, which may lead to a higher reliance on their respective unsecured revolving credit facilities and the related financial institutions for short-term liquidity purposes.

2009 Long-term Debt Transactions and Agreements

In addition to the debt issuances discussed herein, MEHC and its subsidiaries made repayments on MEHC subordinated debt and subsidiary debt totaling $1.178 billion during the year ended December 31, 2009.

- In July 2009, MEHC issued $250 million of its 3.15% Senior Notes due July 15, 2012. The net proceeds are being used for general corporate purposes.

- In January 2009, PacifiCorp issued $350 million of its 5.5% First Mortgage Bonds due January 15, 2019 and $650 million of its 6.0% First Mortgage Bonds due January 15, 2039. The net proceeds were used to repay short-term debt and are being used to fund capital expenditures and for general corporate purposes.

2008 Long-term Debt Transactions and Agreements

In addition to the debt issuances discussed herein, MEHC and its subsidiaries made scheduled repayments on and purchases of MEHC senior and subordinated debt and subsidiary debt totaling $3.234 billion during the year ended December 31, 2008.

- On September 19, 2008, a wholly-owned subsidiary trust of MEHC issued $1.0 billion of 11% mandatory redeemable preferred securities to affiliates of Berkshire Hathaway due in August 2015 and MEHC issued $1.0 billion of 11% subordinated debt to the trust. The proceeds were used to purchase a $1.0 billion investment in Constellation Energy 8% Preferred Stock.
- On July 17, 2008, PacifiCorp issued $500 million of 5.65% first mortgage bonds due July 15, 2018 and $300 million of 6.35% first mortgage bonds due July 15, 2038. The net proceeds were used for general corporate purposes.
- On July 15, 2008, Northern Natural Gas issued $200 million of 5.75% senior notes due July 15, 2018. The net proceeds were used to repay at maturity its $150 million, 6.75% senior notes due September 15, 2008 and the remainder was used for general corporate purposes.

- On July 1, 2008, the Iowa Finance Authority issued $45 million of variable-rate tax-exempt bonds due July 1, 2038, the proceeds of which were loaned to MidAmerican Energy and are restricted for the payment of qualified environmental construction costs. Also on July 1, 2008, the Iowa Finance Authority issued $57 million of variable-rate tax-exempt bonds due May 1, 2023 to refinance $57 million of pollution control revenue refunding bonds issued on behalf of MidAmerican Energy in 1993. These variable-rate tax-exempt bonds are remarketed and the interest rates reset on a weekly basis.
- On March 28, 2008, MEHC issued $650 million of 5.75% senior notes due April 1, 2018. The net proceeds were used for general corporate purposes.
- On March 25, 2008, MidAmerican Energy issued $350 million of 5.3% senior notes due March 15, 2018. The proceeds were used by MidAmerican Energy to pay construction costs, including costs for its wind-powered generation projects in Iowa, repay short-term indebtedness and for general corporate purposes.

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

Future Uses of Cash

The Company 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, the issuance of equity and other sources. These sources are expected to provide funds required for current operations, capital expenditures, acquisitions, investments, debt retirements and other capital requirements. The availability and terms under which each subsidiary has access to external financing depends on a variety of factors, including its credit rating, investors' judgment of risk and conditions in the overall capital market, including the condition of the utility industry in general. Additionally, the Berkshire Equity Commitment can be used 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. 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 any such drawing will be made by means of a cash equity contribution to MEHC in exchange for additional shares of MEHC's common stock. The Berkshire Equity Commitment expires on February 28, 2011.

During 2008 and early 2009, the United States, the United Kingdom 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 who were able to find financing, and in other cases resulted in the unavailability of certain types of debt financing. In 2008 and 2009, the United States federal government enacted legislation in an attempt to stabilize the economy, increased the federal deposit insurance, invested billions of dollars in financial institutions and took other steps to infuse liquidity into the economy. The United States federal government TARP and the current accommodative monetary stance in the United States and most other industrialized countries have reduced liquidity concerns, relieved credit constraints and provided many financial institutions with the ability to strengthen their financial position. However, there is no certainty that the credit environment will improve and it is also possible that financial institutions may not be able to provide previously arranged funding under revolving credit facilities or other arrangements like those that MEHC and its subsidiaries have established as potential sources of liquidity. It is also difficult to predict how the financial markets will react to the United States federal government's gradual withdrawal or removal of certain economic stimulus programs. Uncertainty in the credit markets may negatively impact MEHC and its subsidiaries' ability to access funds on favorable terms or at all. If MEHC or its subsidiaries 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 the Company's capital expenditures, consolidated financial condition and results of operations.

Capital Expenditures

The Company 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 and nuclear; 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, mine reclamation, nuclear decommissioning, hydroelectric relicensing, hydroelectric decommissioning and associated operating costs are generally incorporated into MEHC's energy subsidiaries' regulated retail rates.

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

	2010	2011	2012
Forecasted capital expenditures[(1)]:			
Construction and other development projects	$ 905	$ 746	$ 805
Operating projects	1,668	1,665	1,522
Total	$ 2,573	$ 2,411	$ 2,327

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

Construction and other development projects consist mainly of large scale projects at PacifiCorp and Kern River. Included in the 2010 through 2012 forecasted capital expenditures are PacifiCorp's anticipated costs of $961 million primarily for the Energy Gateway Transmission Expansion Program, 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, Oregon and the desert Southwest. 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 resource areas, including renewable resources; and (e) improve the flow of electricity throughout PacifiCorp's six-state service area and the Western United States. Proposed transmission line segments are re-evaluated to ensure maximum benefits and timing before committing to move forward with permitting and construction. The first major transmission segments associated with this plan are expected to be placed in service during 2010, with other segments placed in service through 2019, depending on siting, permitting and construction schedules.

PacifiCorp anticipates spending $705 million for emissions control equipment, which includes equipment to meet anticipated air quality and visibility targets and the reduction of sulfur dioxide emissions, and $153 million on additional wind-powered generation facilities between 2010 and 2012. Evaluation and development efforts are in progress related to additional prospective wind-powered generating facilities scheduled for completion after 2009.

Kern River anticipates spending $330 million combined for two expansion projects during 2010 and 2011.

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

MidAmerican Energy continues to evaluate additional cost-effective wind-powered generation. In December 2009, the IUB issued an Order approving a settlement agreement between MidAmerican Energy and the OCA in conjunction with MidAmerican Energy's ratemaking principles application to construct up to 1,001 MW (nominal ratings) of additional wind-powered generation in Iowa through 2012, the last 251 MW of which is subject to confirmation from the IUB. MidAmerican Energy has further committed that not greater than 500 MW will be placed in service during 2012. Wind projects under this agreement are authorized to earn a 12.2% return on equity in any future Iowa rate proceeding. The Order has been appealed to the district court in Polk County, Iowa by one of the intervenors in the proceeding. MidAmerican Energy has not entered into any material contracts for the development or construction of new wind-powered generation or the purchase of any related wind turbines.

Contractual Obligations

The Company has contractual obligations that may affect its consolidated financial condition. The following table summarizes the Company's material contractual obligations as of December 31, 2009 (in millions):

	Payments Due By Periods				
	2010	2011-2012	2013-2014	2015 and After	Total
MEHC senior debt	$ -	$ 750	$ 250	$ 4,375	$ 5,375
MEHC subordinated debt	188	257	-	191	636
Subsidiary debt	191	1,965	1,371	10,208	13,735
Interest payments on long-term debt[(1)]	1,196	2,218	1,900	13,809	19,123
Short-term debt	179	-	-	-	179
Coal, electricity and natural gas contract commitments[(1)]	1,190	1,527	824	2,685	6,226
Purchase obligations[(1)]	873	264	64	160	1,361
Operating leases[(1)]	96	136	76	306	614
Other	155	5	5	56	221
Total contractual cash obligations	$ 4,068	$ 7,122	$ 4,490	$ 31,790	$ 47,470

(1) Not reflected on the Consolidated Balance Sheets.

The Company has other types of commitments that arise primarily from unused lines of credit, letters of credit or relate to construction and other development costs (Liquidity and Capital Resources included within this Item 7), debt guarantees (Note 12), asset retirement obligations (Note 13) and uncertain tax positions (Note 15) which have not been included in the above tables because the amount and timing of the cash payments are not certain. Refer, where applicable, to the respective referenced note in Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Regulatory Matters

MEHC's regulated subsidiaries are 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 the general regulatory framework at MEHC's regulated subsidiaries.

Certain regulatory matters are subject to uncertainties that require the use of estimates on the Consolidated Financial Statements. These relate to Iowa electric revenue sharing, rates implemented at Kern River subject to refund and Oregon Senate Bill 408. Refer to Note 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion.

PacifiCorp

PacifiCorp is subject to comprehensive regulation by the UPSC, the OPUC, the WPSC, the WUTC, the IPUC and the CPUC. PacifiCorp pursues a regulatory program in all states, with the objective of keeping rates closely aligned to ongoing costs. PacifiCorp has separate power cost recovery mechanisms in Oregon, Wyoming, Idaho and California. The following discussion provides a state-by-state update.

Utah

In July 2008, PacifiCorp filed a general rate case with the UPSC requesting an annual increase of $161 million prior to any consideration of the UPSC's order in the 2007 general rate case. In September 2008, PacifiCorp filed supplemental testimony that reflected then-current revenue and other adjustments based on the August 2008 order in the 2007 general rate case. The supplemental filing reduced PacifiCorp's request to $115 million. In October 2008, the UPSC issued an order changing the test period from the twelve months ending June 2009 using end-of-period rate base to the forecast calendar year 2009 using average rate base. In December 2008, PacifiCorp updated its filing to reflect the change in the test period. The updated filing proposed an increase of $116 million. In March 2009, a settlement agreement was filed with the UPSC resolving all remaining revenue requirement issues, resulting in parties agreeing, among other settlement terms, on an annual increase of $45 million, or an average price increase of 3%, effective May 8, 2009. In April 2009, the UPSC issued its final order approving the revenue requirement settlement agreement.

In March 2009, Utah's governor signed Senate Bill 75 that provides additional regulatory tools for the UPSC to use in the ratemaking process. The additional tools provided in the legislation allow for single item cost recovery of major capital investments outside of the general rate case process and allow for, but do not require, the use of an energy balancing account.

In March 2009, PacifiCorp filed for an ECAM with the UPSC. The filing recommends 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 has 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. Hearings on the public interest phase were completed in January 2010. In February 2010, the UPSC issued an order to proceed to the second phase to address design considerations in the development of an ECAM. Additionally, 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. If approved, the filing would establish a deferred cost balance to be considered for collection through any potential mechanism established in the second phase of the ECAM proceeding.

In February 2010, an application was filed with the UPSC by the Utah Association of Energy Users requesting an order requiring PacifiCorp to defer for later ratemaking treatment all revenues associated with sales of renewable energy credits in excess of the level included in Utah rates. If approved, Utah's share of any renewable energy credit sales above $18.5 million annually would be subject to consideration in a future proceeding.

In June 2009, PacifiCorp filed a general rate case with the UPSC for an increase of $67 million, or an average price increase of 5%. The forecasted test period is the twelve months ending June 30, 2010. In November 2009, as part of its rebuttal and surrebuttal filings, PacifiCorp reduced its rate increase request to $53 million. The UPSC issued its order February 18, 2010 approving a price increase of $32 million, or an average price increase of 2%.

In June 2009, PacifiCorp filed with the UPSC to increase its DSM cost recovery mechanism in Utah from an average of 2% of a customer's eligible monthly charges to 6%. In August 2009, a settlement agreement was filed with the UPSC requesting the DSM cost recovery mechanism be adjusted to 5%, representing an estimated annual increase of $35 million, which would enable PacifiCorp to continue to fund ongoing DSM programs and to recover previously incurred DSM expenditures. The UPSC approved the settlement agreement in August 2009, and the 5% DSM cost recovery mechanism became effective September 1, 2009.

In February 2010, PacifiCorp filed an alternative cost recovery application with the UPSC requesting recovery of $34 million associated with two major construction projects that are expected to be completed and in-service by June 2010. The mechanism provides for a ruling from the UPSC within 150 days of the application.

Oregon

In March 2009, PacifiCorp made the initial filing for the annual transition adjustment mechanism ("TAM") with the OPUC for an annual increase of $21 million to recover the anticipated net power costs for the year beginning January 1, 2010. In August 2009, PacifiCorp filed a revision to its anticipated net power costs for the TAM, reflecting a slight decrease in the overall request to $20 million. In September 2009, PacifiCorp filed a settlement stipulation with the OPUC reducing the requested increase to $4 million, or an average price increase of less than 1%. In October 2009, the OPUC issued an order approving the settlement stipulation. In November 2009, PacifiCorp filed the final net power costs update for the TAM, based on the latest forward price curve. The final update shows a net power costs increase of $4 million, or an average price increase of less than 1%. The effective date for the TAM was January 1, 2010.

In April 2009, PacifiCorp filed a general rate case with the OPUC requesting an annual increase of $92 million. In August 2009, the requested annual increase was reduced to $83 million. In September 2009, PacifiCorp filed a settlement stipulation with the OPUC further reducing the proposed annual increase to $42 million, or an average price increase of 4%. The stipulation agreement also includes three tariff riders to collect an additional $8 million over a three-year period associated with various cost initiatives. In January 2010, the OPUC approved the stipulation effective February 2, 2010.

In February 2010, PacifiCorp made the 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. The rates in the TAM filing will be effective January 1, 2011 and are subject to updates throughout the proceeding.

Wyoming

In July 2008, PacifiCorp filed a general rate case with the WPSC requesting an annual increase of $34 million with an effective date of May 24, 2009. Power costs were excluded from the filing and were addressed separately in PacifiCorp's annual power cost adjustment mechanism ("PCAM") application filed in February 2009. In October 2008, the general rate case request was reduced by $5 million, to $29 million, to reflect a change in the in-service date of the High Plains wind-powered generating facility. In March 2009, a settlement agreement was filed with the WPSC revising the requested increase in Wyoming rates to $18 million annually beginning May 24, 2009, for an average overall price increase of 4%. Following public hearings in March 2009, the WPSC issued a final order approving the stipulation agreement in May 2009.

In February 2009, PacifiCorp filed its annual PCAM application with the WPSC. The PCAM application requested recovery of the difference between actual net power costs and the amount included in base rates, subject to certain limitations, for the period December 1, 2007 through November 30, 2008, and established for the first time an adjustment for the difference between forecasted net power costs and the amount included in base rates for the period December 1, 2008 through November 30, 2009. In the 2009 PCAM application, PacifiCorp requested a $2 million reduction to the current annual surcharge rate based on the results for the twelve-month period ended November 30, 2008, as well as a $16 million increase to the annual surcharge rate for the forecasted twelve-month period ending November 30, 2009, resulting in a net increase to the annual surcharge rate of $14 million on a combined basis. In March 2009, the WPSC approved PacifiCorp's motion to implement an interim rate increase of $7 million effective April 1, 2009 consistent with the interim PCAM increase agreed to in the 2008 general rate case settlement agreement. In July 2009, a stipulation agreement was signed by the major participants in the case requesting that the April 2009 interim rate increase become the permanent rate for the entire amortization period through March 31, 2010, effectively reducing the net increase of $14 million sought in the application to $7 million, or an average price increase of 1%. In August 2009, the WPSC held a public hearing to consider the stipulation agreement, and after considering the evidence, the WPSC issued a bench decision approving the stipulation effective September 1, 2009.

In October 2009, PacifiCorp filed a general rate case with the WPSC requesting a rate increase of $71 million. Power costs are included in the general rate case, reflecting increased coal costs and the expiration of low cost long-term power purchase contracts. The application is based on a test period ending December 31, 2010. Two regulatory policy issues related to the tax treatment of equity AFUDC and the accounting for coal stripping costs are included in the case, which if approved by the WPSC, will reduce the requested rate increase by $9 million to an overall requested increase of $62 million, or an average price increase of 12%. The application requests a rate effective date of August 1, 2010. The WPSC has scheduled public hearings for April 2010.

In January 2010, PacifiCorp filed its annual PCAM application with the WPSC requesting recovery of $8 million in deferred net power costs.

Washington

In February 2009, PacifiCorp filed a general rate case with the WUTC for an annual increase of $39 million. The filing included a request to begin collection of a deferral for costs associated with the 520-MW Chehalis natural gas-fired generating facility prior to its inclusion in rate base beginning in January 2010. The associated costs are estimated at $15 million. PacifiCorp has proposed to recover these costs through an extension of its hydroelectric deferral mechanism, thereby not affecting current customer rates. In August 2009, PacifiCorp filed an all-party settlement agreement proposing an annual increase of $14 million, or an average price increase of 5%. In December 2009, the WUTC approved the all-party settlement agreement. The new rates became effective January 1, 2010.

Idaho

In September 2008, PacifiCorp filed a general rate case with the IPUC for an annual increase of $6 million. In February 2009, a settlement signed by PacifiCorp, the IPUC staff and intervening parties was filed with the IPUC resolving all issues in the 2008 general rate case. The agreement stipulated a $4 million increase, or an average price increase of 3%, for non-contract retail customers in Idaho. As part of the stipulation, intervening parties acknowledged that PacifiCorp's acquisition of the 520-MW Chehalis natural gas-fired generating facility was prudent and the investment should be included in PacifiCorp's revenue requirement, and that PacifiCorp had demonstrated that its DSM programs are prudent. The parties also agreed on a base level of net power costs for any future ECAM calculations. In April 2009, the IPUC issued an order approving the stipulation effective April 18, 2009.

In June 2009, an agreement was reached with parties to the ECAM docket allowing for the implementation of an ECAM to recover the difference between the base level of net power costs recovered in rates and actual costs incurred, subject to the calculation methodology of the mechanism. In September 2009, the IPUC issued an order approving the ECAM stipulation as filed with an effective date of July 1, 2009. In February 2010, PacifiCorp filed an ECAM application with the IPUC requesting recovery of $2 million in deferred net power costs.

Northern Natural Gas

In November 2009, the FERC issued an order initiating a rate proceeding under Section 5 of the NGA for the purpose of investigating whether Northern Natural Gas' rates are just and reasonable. The case was assigned to an administrative law judge and an initial decision by the administrative law judge must be issued in November 2010. In February 2010, Northern Natural Gas filed a cost and revenue study pursuant to the FERC's order that demonstrated no adjustment to Northern Natural Gas' rates were warranted. Northern Natural Gas believes that the ultimate resolution of the matter will not have a material adverse effect on the Company's consolidated financial results.

CE Electric UK

In December 2009, Northern Electric and Yorkshire Electricity accepted Ofgem's final proposal for the distribution price control review. The new price control formula will be effective April 1, 2010 and is expected to cover the next five years.

As a result of these changes, it is expected the base allowed revenue of Northern Electric and Yorkshire Electricity will be permitted to increase by approximately 7.7% and 6.5%, respectively, plus inflation (as measured by the change in the United Kingdom's retail prices index) in each year of the new control.

Environmental Laws and Regulation

The Company is subject to federal, state, local and foreign laws and regulations regarding air and water quality, renewable portfolio standards, climate change, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact the Company'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, local and international 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 the Company is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. The Company believes it is in material compliance with all applicable laws and regulations. Refer to "Future Uses of Cash" for discussion of the Company'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 are subject to public hearings, must be approved by the EPA and vary by state. 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 the Company'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 oxide, particulate matter, ozone and SO_2, 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 2008, the EPA notified Iowa that portions of Scott County, where MidAmerican Energy's Riverside coal-fired generating facility is located, and Muscatine County, adjacent to Louisa County, where MidAmerican Energy's Louisa coal-fired generating facility is located, did not meet the December 2006 fine particulate matter standard based on monitoring data from 2005 to 2007; however, based on monitoring data from 2006 to 2008, the fine particulate matter standard was met and the counties are considered to be in attainment. On October 9, 2009, the EPA issued its final notice designating all areas of Iowa as being in attainment of the standard. Currently, air quality monitoring data indicate that all counties where MidAmerican Energy's major emission sources are located are in attainment of the current national ambient air quality standards.

On December 14, 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 expects to issue final standards later in 2010 with SIPs submitted in 2013.

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

In November 2009, the EPA proposed a new national ambient air quality standard for SO_2 to a level of between 50 and 100 parts per billion measured over one hour. The existing primary standards for SO_2 are 140 parts per billion measured over 24 hours and 30 parts per billion measured over an entire year. The EPA is under a consent decree to take final action on the proposed standards by June 2010.

If the stricter standards are implemented, the number of counties designated as nonattainment areas may 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 the EPA issues the final rules and any legal challenges are settled, the impacts on the Company 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” rather than a cap-and-trade system. Under a consent decree, the EPA must issue a proposed rule to regulate mercury emission 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 the Company’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 and MidAmerican Energy cannot be determined.

Clean Air Interstate Rule

The EPA promulgated the CAIR in March 2005 to reduce emissions of NO_x and SO_2, precursors of ozone and particulate matter, from down-wind sources. The CAIR required states in the eastern United States, including Iowa, to reduce emissions by implementing a plan based on a market-based cap-and-trade system, emission reductions, or both. The CAIR created separate trading programs for NO_x and SO_2 emission credits. The NO_x and SO_2 emissions reductions were planned to be accomplished in two phases, in 2009-2010 and 2015.

In July 2008, a three-judge panel of the D.C. Circuit issued a unanimous decision vacating the CAIR. In December 2008, the D.C. Circuit issued an opinion remanding, without vacating, the CAIR back to the EPA to conduct proceedings to fix the flaws in CAIR consistent with the D.C. Circuit’s July 2008 ruling. The D.C. Circuit did not impose a schedule for completion on the EPA in its ruling, and the EPA informed the D.C. Circuit that development and finalization of a replacement rule could take approximately two years.

PacifiCorp’s generating facilities are not subject to the CAIR. MidAmerican Energy is currently required to comply with the CAIR provisions until such time as the EPA promulgates a new rule. As a result, MidAmerican Energy purchases NO_x and SO_2 emission credits for emissions in excess of allocated allowances. The cost of these credits is subject to market conditions at the time of purchase and historically has not been material. The impact of the replacement rule cannot be determined until the EPA issues its final rule. It is possible that the existing CAIR may be replaced with more stringent requirements to reduce SO_2 and NO_x emissions and that these requirements could be extended to the western United States through regulation or legislation such as the Clean Air Act Amendments of 2010, introduced in February 2010 by Senators Carper and Alexander.

CalEnergy Generation-Domestic’s natural gas generating facilities in Texas, Illinois and New York are also subject to the CAIR. However, the provisions are not anticipated to have a material impact on the Company.

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 and MidAmerican Energy’s generating facilities meet the threshold applicability criteria 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 emission 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. Iowa submitted its SIP to the EPA and suggested that the emission reductions already made by MidAmerican Energy and additional reductions that will be made under the CAIR place the state in the position that no further reductions should be required. Wyoming has not yet submitted its SIP. Wyoming issued best available retrofit technology permits to PacifiCorp on December 31, 2009, requiring PacifiCorp to implement emission control projects that are consistent with the planned emission reduction projects at PacifiCorp’s Wyoming generating facilities. PacifiCorp has appealed certain provisions of the Naughton and Jim Bridger generating facilities’ permits. Utah submitted its SIP and suggested that the emission reduction projects planned by PacifiCorp are sufficient to meet its initial emission reduction requirements. In January 2009, the EPA made a finding that 37 states, including Wyoming, had failed to file a SIP that met some or all of the basic regional haze program requirements. As a result, Wyoming has two years from January 2009 to file and obtain the EPA’s approval of a SIP that meets all of the regional haze program requirements or the state will be subject to a federal implementation plan administered by the EPA. PacifiCorp believes that its planned emission 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 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 and MidAmerican Energy responded to requests for information relating to their capital projects at their 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 historic projects did not meet all regulatory requirements. MidAmerican Energy currently has no outstanding data requests from the EPA.

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, and the recent change in administration, create risk and uncertainty for entities when seeking permits for new projects and installing emission controls at existing facilities under NSR requirements. The Company 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 and federal policy makers, with President Obama's support, are considering comprehensive climate change legislation such as the American Clean Energy and Security Act of 2009 ("Waxman-Markey bill"), which includes a market-based cap-and-trade program that is 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. In early 2010, legislation and resolutions were introduced in the United States Congress that would disapprove the findings submitted by the EPA and clarify that the United States Congress did not intend to regulate GHG emissions under the Clean Air Act. To date, two bills, one by Representative Early Pomeroy and one by Representatives Ike Skelton, Collin Peterson and Jo Ann Emerson, have been introduced in the United States House of Representatives seeking to amend the Clean Air Act to preclude the EPA from regulating GHG emissions under the Clean Air Act. In addition, a disapproval resolution has been introduced by Senator Lisa Murkowski and others in the Senate disapproving the EPA's GHG endangerment finding. Litigation has also been filed in the D.C. Circuit challenging EPA's GHG endangerment finding, including an action by twelve members of the United States House of Representatives. An additional 15 lawsuits have been filed by states, various industry groups, and others, petitioning the court for review of the endangerment finding.

The Company supports the implementation of reasonable emissions caps, but opposes the trading mechanism as imposing additional costs that do not result in decreased emissions. The Company 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 legislative initiatives to report or mitigate GHG emissions. In addition, governmental, non-governmental and environmental organizations have become more active in pursuing litigation under existing laws.

PacifiCorp voluntarily reports its GHG emissions to the California Climate Action Registry and The Climate Registry. MidAmerican Energy voluntarily reports its GHG emissions to 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, MidAmerican Energy and CalEnergy Generation-Domestic are subject to this requirement and will submit their first reports by March 31, 2011.

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

- MidAmerican Energy is the largest and PacifiCorp is the second largest owner of wind-powered generation capacity in the United States among rate-regulated utilities. Over the last three years, the Company has added 1,611 MW of owned wind generation capacity at a total cost of $3.2 billion to its portfolio of generating assets. The Company currently owns 2,205 MW of wind-powered generation capacity, excluding its 111-MW Dunlap Ranch I wind-powered generating facility that is currently under construction. Additionally, the Company has purchase power agreements with 818 MW of wind-powered generation capacity.
- PacifiCorp owns 1,158 MW of hydroelectric generation capacity.
- PacifiCorp's Energy Gateway Transmission Expansion Program represents a plan to build approximately 2,000 miles of new high-voltage transmission lines at a 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 resource areas, including renewable resources; and (e) improve the flow of electricity throughout PacifiCorp's six-state service area and the Western United States.
- ETT has been assigned approximately $800 million of transmission investment in support of CREZ. CREZ is a transmission plan that advances the development of over 18,000 MW of new wind-powered generation in Texas.
- PacifiCorp and MidAmerican Energy have 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.
- MEHC holds a 10% interest in BYD, which continues to make advances in applying its proprietary battery technology to electric vehicles and has also developed electric storage stations, solar power stations and other technologies that can be applied to promote the use of renewable generation.

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 laws, regulations or rules limiting GHG emissions could have a material adverse impact on the Company, 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 emission 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 laws and regulations may impact the Company include:

- Additional costs may be incurred to purchase required emission allowances under the proposed 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

- The Company's natural gas pipeline operations, electric transmission and retail sales may be impacted in response to changes in customer demand and requirements to reduce GHG emissions.

MEHC expects its regulated subsidiaries 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 the Company's existing and future electricity generation 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

The December 2009 Copenhagen Accord called on officials from developed nations to voluntarily commit to quantified economy-wide emissions targets for 2020 by January 31, 2010. In January 2010, the Obama administration formally declared its desire to be associated with the Copenhagen Accord, informing the United Nations Framework Convention on Climate Change of the goal of reducing United States GHG emissions approximately 17% from 2005 levels by 2020, contingent upon the enactment of United States energy and climate change legislation. The United States' goal is not binding or enforceable absent further action by the United States Congress to enact climate change legislation.

Federal Legislation

In June 2009, the United States House of Representatives passed the Waxman-Markey bill. In addition to a federal RPS, which would require utilities to obtain a portion of their energy from certain qualifying renewable sources and energy efficiency measures, the bill requires a reduction in GHG emissions beginning in 2012, with emission 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. In September 2009, a similar bill was introduced in the United States Senate by Senators Barbara Boxer and John Kerry, which would require a reduction in GHG emissions beginning in 2012 with emission reduction targets consistent with the Waxman-Markey bill, with the exception of the 2020 target, which requires 20% reductions below 2005 levels.

Greenhouse Gas Tailoring Rule

The EPA published a proposed GHG "tailoring rule" in October 2009 that would require sources of GHG emissions in excess of 25,000 tons of CO_2 equivalent to conduct a determination of best available control technology under the PSD provisions for new and modified sources. In addition, the proposal would require sources of CO_2 equivalent emissions of 25,000 tons or more to obtain a Title V operating permit or incorporate GHG emissions into existing sources' Title V permits when they are renewed. The EPA is currently working to finalize the rules with an anticipated effective date for stationary sources beginning in 2011. Until final rules are issued, the Company cannot determine the impact on its facilities. Several organizations have indicated that they intend to challenge the EPA's final GHG tailoring rule.

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, MidAmerican Energy and other MEHC energy subsidiaries, 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 occur in 2010. The first phase of the cap-and-trade program will 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. In addition, California has adopted legislation that imposes a GHG emission performance standard to all electricity generated within the state or delivered from outside the state that is no higher than the GHG emission 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. An effort is currently underway to gather a sufficient number of signatures to institute a California ballot initiative, referenced as the "California Jobs Initiative", which seeks to place before the voters a requirement to suspend GHG regulations promulgated under California's GHG emission reduction legislation (Assembly Bill 32) until California's unemployment rate is lowered to 5.5%.
- Over the past three 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 CO_2 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.
- In Iowa, legislation enacted in 2007 required the Iowa Climate Change Advisory Council ("ICCAC"), a 23-member group appointed by the Iowa governor, to develop scenarios designed to reduce statewide GHG emissions, including one scenario that would reduce emissions by 50% by 2050, and submit its recommendations to the legislature. The ICCAC also developed a second scenario to reduce GHG emissions by 90% with reductions in both scenarios from 2005 emission levels. In January 2009, the ICCAC presented to the Iowa governor and legislature several policy options to consider to achieve GHG emissions reductions, including enhanced energy efficiency programs and increased renewable generation. No legislation has yet been enacted that would require GHG emission reductions.
- In November 2007, the Iowa governor signed the Midwest Greenhouse Gas Accord and the Energy Security and Climate Stewardship Platform for the Midwest. The signatories to the platform were other Midwestern states that agreed to implement a regional cap-and-trade system for GHG emissions by May 2010. Current advisory group recommendations include the assessment of 2020 emission reduction targets of 15%, 20% and 25% below 2005 levels and a 2050 target of 60% to 80% below 2005 levels. In addition, the accord calls for the participating states to collectively meet at least 2% of regional annual retail sales of electricity and natural gas through energy efficiency improvements by 2015 and continue to achieve an additional 2% in efficiency improvements every year thereafter.
- The Regional Greenhouse Gas Initiative, a mandatory, market-based effort to reduce GHG emissions in ten Northeastern and Mid-Atlantic states, requires, beginning in 2009, the reduction of CO_2 emissions from the power sector of 10% by 2018.

Greenhouse Gas Litigation

The Company closely monitors ongoing environmental litigation. Many of the pending cases described below relate to lawsuits against industry that attempt to link GHG emissions to public or private harm. The Company believes the cases are without merit, despite recent decisions where United States Court of Appeals reversed district court rulings dismissing the cases in 2009. The lower courts initially refrained from adjudicating the cases under the "political question" doctrine, because of their inherently political nature. Nevertheless, an adverse ruling in any of these cases would likely result in increased regulation of GHG emitters, including the Company's generating facilities, and financial uncertainty.

In September 2009, the United States Court of Appeals for the Second Circuit ("Second Circuit") issued its opinion in the case of *Connecticut v. American Electric Power, et al*, which remanded to the lower court a nuisance action by eight states and the City of New York against five large utility emitters of CO_2. The United States District Court for the Southern District of New York ("Southern District of New York") dismissed the case in 2005, holding that the claims that GHG emissions from the defendants' coal-fueled generating facilities were causing harmful climate change and should be enjoined as a public nuisance under federal common law presented a "political question" that the court lacked jurisdiction to decide. The Second Circuit rejected this conclusion and stated the Southern District of New York was not precluded from determining the case on its merits.

In October 2009, a three judge panel in the United States Court of Appeals for the Fifth Circuit ("Fifth Circuit") issued its opinion in the case of *Ned Comer, et al. v. Murphy Oil USA, et al*., a putative class action lawsuit against insurance, oil, coal and chemical companies, based on claims that the defendants' GHG emissions contributed to global warming that in turn caused a rise in sea levels and added to the ferocity of Hurricane Katrina, which combined to damage the plaintiff's private property, as well as public property. In 2007, the United States District Court for the Southern District of Mississippi ("Southern District of Mississippi") dismissed the case based on the lack of standing and further held that the claims were barred by the political question doctrine. The Fifth Circuit reversed the lower court decision and held that the plaintiffs had standing to assert their public and private nuisance, trespass and negligence claims, and concluded that the claims did not present a political question. The case was remanded to the Southern District of Mississippi for further proceedings with the court noting that it had not determined, and would leave to the lower court to analyze, whether the alleged chain of causation satisfies the proximate cause requirement under Mississippi state common law.

In October 2009, the United States District Court for the Northern District of California ("Northern District of California") granted the defendants' motions to dismiss in the case of *Native Village of Kivalina v. ExxonMobil Corporation, et al*. The plaintiffs filed their complaint in February 2008, asserting claims against 24 defendants, including electric generating companies, oil companies and a coal company, for public nuisance under state and federal common law based on the defendants' GHG emissions. MEHC was a named defendant in the Kivalina case. The Northern District of California dismissed all of the plaintiffs' federal claims, holding that the court lacked subject matter jurisdiction to hear the claims under the political question doctrine, and that the plaintiffs lacked standing to bring their claims. The Northern District of California declined to hear the state law claims and the case was dismissed with prejudice to their future presentation in an appropriate state court.

Several lawsuits have also been filed against governmental agencies, most notably *Massachusetts v. EPA*. In April 2007, in Massachusetts v. EPA, the United States Supreme Court found that GHG are air pollutants and are covered by the Clean Air Act. The United States Supreme Court decision resulted from a petition for rulemaking filed by more than a dozen environmental, renewable energy and other organizations. The court held that the EPA must determine whether or not GHG emissions contribute to air pollution which may reasonably be anticipated to endanger public health or welfare, or whether the science is too uncertain to make a reasoned decision. In December 2009, the EPA determined that GHG emissions in the atmosphere threaten the public health and welfare of current and future generations and is pursuing regulation of GHG emissions under the Clean Air Act. Unless superseded by congressional action, the EPA ruling is likely to lead to stricter emission limits.

Renewable Portfolio Standards

The RPS described below could significantly impact the Company'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 the Company 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 law requires electric utilities to increase their procurement of 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 renewable resources by no later than December 31, 2010. In May 2008, PacifiCorp and other small multi-jurisdictional utilities ("SMJU") received further guidance from the CPUC on the treatment of SMJUs in the California RPS program. In August 2008, concurrent with its annual RPS compliance filing, PacifiCorp, joined by another SMJU, filed a Joint Motion for Review of the decision, including banking of RPS procurement made while it awaited further guidance from the CPUC on the treatment of SMJUs during the 2004-2006 period. In May 2009, the CPUC denied the Joint Motion for Review.

In September 2009, California's governor issued Executive Order S-21-09 requiring the California Air Resources Board to adopt a regulation consistent with a 33% renewable electricity energy target established in Executive Order S-14-08 by July 31, 2010 that will encourage the creation and use of renewable energy sources and build on the existing RPS program.

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 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 Plant and all of MidAmerican Energy's coal-fired generating facilities, except Louisa, Ottumwa and Walter Scott, Jr. Unit 4, which have water cooling towers, exceed the 50 million gallons of water per day intake threshold. In the event that PacifiCorp's or MidAmerican Energy's existing intake structures require modification or alternative technology required by new rules, expenditures to comply with these requirements could be significant. The Company 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 coal combustion storage and disposal. The EPA is currently considering the regulation of coal combustion byproducts under the Resource Conservation and Recovery Act and a proposed rule addressing these materials is imminent. PacifiCorp operates 16 surface impoundments and 6 landfills that contain coal combustion byproducts. MidAmerican Energy operates 8 surface impoundments and 4 landfills that contain coal combustion byproducts. These ash impoundments and landfills may be impacted by additional regulation, particularly if the materials are regulated as hazardous waste under Subtitle C of the Resource Conservation Act, and could pose significant additional costs associated with ash management and disposal activities at the Company's coal-fired generating facilities. The impact of any new regulations on coal combustion byproducts cannot be determined at this time.

Other

Other laws, regulations and agencies to which the Company is subject 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. Refer to Note 16 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding environmental contingencies.
- The Nuclear Waste Policy Act of 1982, under which the United States Department of Energy is responsible for the selection and development of repositories for, and the permanent disposal of, spent nuclear fuel and high-level radioactive wastes. 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. Refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding nuclear decommissioning and mine reclamation obligations.
- 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 16 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.

Credit Ratings

MEHC's senior unsecured debt credit ratings are as follows: Moody's Investors Service, "Baa1/stable;" Standard & Poor's Rating Services, "BBB+/stable;" and Fitch Ratings, "BBB+/stable." Debt and preferred securities of MEHC and certain of its subsidiaries are rated by the credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of the rated company'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.

MEHC and its subsidiaries have 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. The Company's unsecured revolving credit facilities do not require the maintenance of a minimum credit rating level in order to draw upon their availability but, under certain instances, must maintain sufficient covenant tests if ratings drop below a certain level. 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.

In accordance with industry practice, certain agreements, including derivative contracts, contain provisions that require certain of MEHC's subsidiaries, principally the Utilities, to maintain specific credit ratings on their unsecured debt from one or more of the major credit ratings 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 the subsidiary's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2009, these subsidiary'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, 2009, the Company would have been required to post $669 million of additional collateral. The Company's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings 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 the Company's collateral requirements specific to the Company's derivative contracts.

Inflation

Historically, overall inflation and changing prices in the economies where MEHC's subsidiaries operate have not had a significant impact on the Company's consolidated financial results. In the United States, MEHC's regulated subsidiaries operate under cost-of-service based rate structures administered by various state commissions and the FERC. Under these rate structures, MEHC's regulated subsidiaries are allowed to include prudent costs in their rates, including the impact of inflation. The price control formula used by the United Kingdom distribution companies incorporates the rate of inflation in determining their rates. MEHC's subsidiaries attempt to minimize the potential impact of inflation on their 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

The Company has certain investments that are accounted for under the equity method in accordance with accounting principles generally accepted in the United States of America ("GAAP"). Accordingly, an amount is recorded on the Company's Consolidated Balance Sheets as an equity investment and is increased or decreased for the Company's pro-rata share of earnings or losses, respectively, less any dividend distribution from such investments.

As of December 31, 2009, the Company's investments that are accounted for under the equity method had short- and long-term debt of $550 million, unused revolving credit facilities of $101 million and letters of credit outstanding of $71 million. As of December 31, 2009, the Company's pro-rata share of such short- and long-term debt was $275 million, unused revolving credit facilities was $51 million and outstanding letters of credit was $35 million. The entire amount of the Company's pro-rata share of the outstanding short- and long-term debt and unused revolving credit facilities is non-recourse to the Company. $31 million of the Company's pro-rata share of the outstanding letters of credit is recourse to the Company. Although the Company is generally not required to support debt service obligations of its equity investees, default with respect to this non-recourse short- and long-term debt could result in a loss of invested equity.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting the Company, 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 the Company's methods, judgments and assumptions used in the preparation of the Consolidated Financial Statements and should be read in conjunction with the Company'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, MidAmerican Energy, Northern Natural Gas and Kern River (the "Domestic Regulated Businesses") prepare their financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, the Domestic Regulated Businesses are 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 regulated rates.

The Company continually evaluates the applicability of the guidance for regulated operations and assesses whether its regulatory assets and liabilities are probable of future inclusion in regulated 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 the Domestic Regulated Businesses' ability to recover their costs. Based upon this continuous assessment, the Company believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in regulated rates. The assessment reflects the current political and regulatory climate at both the state and federal levels and is subject to change in the future. If it becomes no longer probable that these costs or income will be included in regulated rates, the related regulatory assets and liabilities will be written off to operating income, refunded to customers or reflected as an adjustment to future regulated rates. Total regulatory assets were $2.093 billion and total regulatory liabilities were $1.603 billion as of December 31, 2009. Refer to Note 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Domestic Regulated Businesses' regulatory assets and liabilities.

Derivatives

The Company is exposed to the impact of market fluctuations in commodity prices, interest rates and foreign currency exchange rates. Exposures to commodity prices consist mainly of variations in the price of fuel to generate electricity, wholesale electricity that is purchased or sold, and natural gas supply for regulated and nonregulated retail customers. Electricity and natural gas prices are subject to wide price swings as supply and demand for these commodities are impacted by, among many other unpredictable items, changing 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. Additionally, the Company is exposed to foreign currency exchange rate risk from its business operations and investments in Great Britain. Each of the Company's business platforms 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. The Company 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; interest rate risk; and foreign currency exchange rate risk. The Company does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

Measurement Principles

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at fair value unless they are designated as normal purchases and normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is determined using unadjusted quoted prices for identical contracts on the applicable exchange in which the Company transacts. When quoted prices for identical contracts are not available, the Company uses forward price curves. Forward price curves represent the Company's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. The Company 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 the Company. Market price quotations for certain major electricity and natural gas trading hubs are generally readily obtainable for the first six years; therefore, the Company'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, the Company 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 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 fair value of the contracts.

Classification and Recognition Methodology

Almost all of the Company's derivative contracts are probable of inclusion in the rates of its rate-regulated subsidiaries or are accounted for as cash flow hedges. Therefore, changes in the fair value of derivative contracts are generally recorded as net regulatory assets or liabilities 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, 2009, the Company had $353 million recorded as net regulatory assets and $81 million recorded as AOCI, before tax, related to derivative contracts on the Consolidated Balance Sheets. If it becomes no longer probable that a derivative will be included in regulated rates, the regulatory asset or liability will be written off and recognized in earnings. For the Company's derivatives designated as hedging contracts, the Company discontinues hedge accounting prospectively when it has determined that a derivative 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 no longer qualifies as an effective hedge, future changes in the value of the derivative 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 are immediately recognized in earnings.

Impairment of Long-Lived Assets and Goodwill

The Company evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable, or the assets meet the criteria of held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated discounted present value of the expected future cash flows from using the asset. For regulated assets, any impairment charge is offset by the establishment of a regulatory asset to the extent recovery in future rates is probable. Substantially all property, plant and equipment was used in regulated businesses as of December 31, 2009. For all other assets, any resulting impairment loss is reflected on the Consolidated Statements of Operations.

The estimate of cash flows arising from the future use of the asset that are used in the impairment analysis requires judgment regarding what the Company would expect to recover from the future use of the asset. Changes in judgment that could significantly alter the calculation of the fair value or the recoverable amount of the asset may result from significant changes in the regulatory environment, the business climate, management’s plans, legal factors, market price of the asset, the use of the asset or the physical condition of the asset, future market prices, load growth, competition and many other factors over the life of the asset. Any resulting impairment loss is highly dependent on the underlying assumptions and could significantly affect the Company’s results of operations.

The Company’s Consolidated Balance Sheet as of December 31, 2009 includes goodwill of acquired businesses of $5.078 billion. The Company evaluates goodwill for impairment at least annually and completed its annual review as of October 31. Additionally, no indicators of impairment were identified as of December 31, 2009. A significant amount of judgment is required in estimating the fair value of a reporting unit and performing goodwill impairment tests. The Company uses a variety of methods to determine fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; earnings before interest, taxes, depreciation and amortization (“EBITDA”) multiples; and an appropriate discount rate. Estimated future cash flows are impacted by, among other factors, growth rates, changes in regulations and rates, ability to renew contracts and estimates of future commodity prices. In estimating future cash flows, the Company incorporates current market information, as well as historical factors.

Pension and Other Postretirement Benefits

The Company sponsors defined benefit pension and other postretirement benefit plans that cover the majority of its employees. The Company 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, 2009, the Company recognized a net liability totaling $885 million for the under-funded status of the Company’s defined benefit pension and other postretirement benefit plans. As of December 31, 2009, amounts not yet recognized as a component of net periodic benefit cost that were included in net regulatory assets totaled $604 million and AOCI totaled $716 million.

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. The Company believes that the assumptions utilized in recording obligations under the plans are reasonable based on prior experience and current market conditions. Refer to Note 14 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for disclosures about the Company’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, 2009.

The Company 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, the Company reviews the expected asset allocation and develops return assumptions for each asset class based on historical performance and forward-looking views of the financial markets. Pension and other postretirement benefit expenses increase as the expected long-term rate of return on plan assets decreases. The Company regularly reviews its actual asset allocations and periodically rebalances its investments to its targeted allocations when considered appropriate.

The Company 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 14 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 the amount of pension and other postretirement benefit expense recorded 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):

	Domestic Plans					
	Pension Plans		**Other Postretirement Benefit Plans**		**United Kingdom Pension Plan**	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**	**+0.5%**	**-0.5%**
Effect on December 31, 2009 Benefit Obligations:						
Discount rate	$ (89)	$ 98	$ (39)	$ 44	$ (128)	$ 141
Effect on 2009 Periodic Cost:						
Discount rate	$ (5)	$ 6	$ -	$ -	$ (5)	$ 16
Expected rate of return on plan assets	(8)	8	(3)	3	(3)	13

A variety of factors affect the funded status of the plans, including asset returns, discount rates, plan changes and the plan funding practices of the Company. Federal laws may require the Company to increase future contributions to its domestic 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 the Company's income taxes, management is required to interpret complex tax laws and regulations, which includes consideration of regulatory implications imposed by the Company's various regulatory jurisdictions. In preparing tax returns, the Company is subject to continuous examinations by federal, state, local and foreign 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. Although the ultimate resolution of the Company's federal, state, local and foreign tax examinations is uncertain, the Company 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 the Company's consolidated financial results. Assets and liabilities are established for uncertain tax positions taken or positions expected to be taken in income tax returns when such positions are judged to not meet the "more-likely-than-not" threshold based on the technical merits of the position.

The Utilities are required to pass income tax benefits related to certain property-related basis differences and other various differences on to their customers in most state jurisdictions. These amounts were recognized as a net regulatory asset totaling $737 million as of December 31, 2009 and will be included in regulated rates when the temporary differences reverse. Management believes the existing net regulatory assets are probable of inclusion in regulated rates. If it becomes no longer probable that these costs will be included in regulated rates, the related regulatory asset will be written off to operating income.

The Company has not provided United States federal deferred income taxes on its currency translation adjustment or the cumulative earnings of international subsidiaries that have been determined by management to be reinvested indefinitely. The cumulative earnings related to ongoing operations determined to be reinvested indefinitely were approximately $1.323 billion as of December 31, 2009. Because of the availability of United States foreign tax credits, it is not practicable to determine the United States federal income tax liability that would be payable if such earnings were not reinvested indefinitely. Deferred taxes are provided for earnings of international subsidiaries when the Company plans to remit those earnings. The Company periodically evaluates its cash requirements in the United States and abroad and evaluates its short- and long-term operational and fiscal objectives in determining whether the earnings of its foreign subsidiaries are indefinitely invested outside the United States or will be remitted to the United States within the foreseeable future.

Revenue Recognition - Unbilled Revenue

Unbilled revenue was $441 million as of December 31, 2009. Revenue from energy business customers is recognized as electricity or natural gas is delivered or services are provided. The determination of customer billings is based on a systematic reading of meters, fixed reservation charges based on contractual quantities and rates or, in the case of the United Kingdom distribution businesses, when information is received from the national settlement system. 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 generally 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

The Company's Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. The Company's significant market risks are primarily associated with commodity prices, interest rates and foreign currency exchange rates. The following sections address the significant market risks associated with the Company's business activities. The Company also has 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 the Company's accounting for derivative contracts.

Commodity Price Risk

The Company is principally exposed to electricity and natural gas commodity price risk through MEHC's ownership of the Utilities as they have an obligation to serve retail customer load in their regulated service territories. MidAmerican Energy also provides nonregulated retail electricity and natural gas services in competitive markets. The Utilities' load and generation assets represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel to generate electricity, wholesale electricity that is purchased and sold, and natural gas supply for regulated and nonregulated retail gas customers. Electricity and natural gas prices are subject to wide price swings as supply and demand for these commodities are impacted by, among many other unpredictable items, changing weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. To mitigate a portion of its commodity price risk, the Company uses commodity contracts, which may be derivatives, including forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. The Company does not hedge all of its commodity price risk, thereby exposing the unhedged portion to changes in market prices. The settled cost of these contracts is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and that are probable of inclusion in regulated rates are recorded as net regulatory assets or liabilities. Consolidated financial results may be negatively impacted if the costs of wholesale electricity, natural gas or fuel are higher than what is permitted to be included in regulated rates. The Company does not engage in a material amount of proprietary trading activities.

The table that follows summarizes the Company's commodity risk on energy derivative contracts, excluding collateral netting of $49 million and $129 million as of December 31, 2009 and 2008, respectively, and shows the effects of a hypothetical 10% increase and 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 – Net Asset (Liability)	Hypothetical Price Change	Estimated Fair Value after Hypothetical Change in Price
As of December 31, 2009	$ (438)	10% increase	$ (398)
		10% decrease	(478)
As of December 31, 2008	$ (528)	10% increase	$ (474)
		10% decrease	(582)

Interest Rate Risk

The following table summarizes the Company's fixed-rate long-term debt and the estimated total fair values which would result from hypothetical increases or decreases in interest rates in effect as of December 31. Because of their fixed interest rates, these instruments do not expose the Company to the risk of earnings loss due to changes in market interest rates. In general, such increases and decreases in fair value would impact earnings and cash flows only if the Company were to reacquire all or a portion of these instruments prior to their maturity. It is assumed that the changes occur immediately and uniformly to each debt instrument. The hypothetical changes in market interest rates do not reflect what could be deemed best or worst case scenarios. Variations in market interest rates could produce significant changes in the timing of repayments due to prepayment options available. For these reasons, actual results might differ from those reflected in the table (dollars in millions).

			Estimated Fair Value after Hypothetical Change in Interest Rates (bp = basis points)	
	Carrying Value	Fair Value	100 bp decrease	100 bp increase
As of December 31, 2009	$ 18,843	$ 20,133	$ 22,106	$ 18,482
As of December 31, 2008	$ 18,485	$ 18,485	$ 20,196	$ 17,021

As of December 31, 2009 and 2008, the Company had floating-rate obligations totaling $909 million and $911 million, respectively, that expose the Company to the risk of increased interest expense in the event of increases in short-term interest rates. This market risk is not hedged; however, if floating interest rates were to increase by 10% from December 31 levels, it would not have a material effect on the Company's consolidated annual interest expense in either year. The carrying value of the floating-rate obligations approximates fair value as of December 31, 2009 and 2008.

Foreign Currency Exchange Rate Risk

MEHC's business operations and investments outside the United States increase its risk related to fluctuations in foreign currency exchange rates primarily in relation to the British pound. MEHC's principal reporting currency is the United States dollar, and the value of the assets and liabilities, earnings, cash flows and potential distributions from MEHC's foreign operations changes with the fluctuations of the currency in which they transact.

CE Electric UK's functional currency is the British pound. At December 31, 2009, a 10% devaluation in the British pound to the United States dollar would result in the Company's Consolidated Balance Sheet being negatively impacted by a $214 million cumulative translation adjustment in AOCI. A 10% devaluation in the average currency exchange rate would have resulted in lower reported earnings for CE Electric UK of $18 million in 2009.

Credit Risk

Domestic Regulated Operations

The Utilities extend unsecured credit to other utilities, energy marketers, 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.

The Utilities analyze the financial condition of each significant wholesale counterparty before entering into any transactions, establish limits on the amount of unsecured credit to be extended to each counterparty and evaluate the appropriateness of unsecured credit limits on an ongoing basis. To mitigate exposure to the financial risks of wholesale counterparties, the Utilities enter into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. Counterparties may be assessed interest fees for delayed payments. If required, the Utilities exercise rights under these arrangements, including calling on the counterparty’s credit support arrangement.

As of December 31, 2009, PacifiCorp’s aggregate credit exposure from wholesale activities totaled $846 million, based on settlement and mark-to-market exposures, net of collateral. As of December 31, 2009, $660 million, or 78%, of PacifiCorp’s credit exposure was with counterparties having investment grade credit ratings by either Moody’s Investor Service and Standard & Poor’s Rating Services. Two counterparties comprised $351 million, or 41%, of the aggregate credit exposure as of December 31, 2009. One counterparty is 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 counterparty’s credit ratings to below investment grade over the remaining term of transactions outstanding as of December 31, 2009. The other counterparty has a non-investment grade credit rating based on internal review as of December 31, 2009.

As of December 31, 2009, MidAmerican Energy’s aggregate direct credit exposure from wholesale activities totaled $37 million, based on settlement and mark-to-market exposures, net of collateral. As of December 31, 2009, $29 million, or 78%, of MidAmerican Energy’s direct credit exposure was with counterparties having investment grade credit ratings by either Moody’s Investor Service or Standard & Poor’s Rating Services, while an additional $8 million, or 22%, of the direct credit exposure was with counterparties having financial characteristics deemed equivalent to investment grade based on internal review. A single counterparty comprises $11 million, or 31%, of the aggregate direct credit exposure as of December 31, 2009 and is rated investment grade by Moody’s Investor Service and Standard & Poor’s Rating Services. MidAmerican Energy is not aware of any factors that would likely result in a downgrade of the counterparty’s credit ratings to below investment grade over the remaining term of transactions outstanding as of December 31, 2009.

MidAmerican Energy also has potential indirect credit exposure to other market participants in the RTO markets where it actively participates, including MISO, PJM, and ERCOT. In the event of a default by a RTO market participant on its market-related obligations, losses are allocated among all other market participants in proportion to each participant’s share of overall market activity during the period of time the loss was incurred. Transactional activities of MidAmerican Energy and other participants in organized RTO markets are governed by credit policies specified in each respective RTO’s governing tariff or related business practices. Credit policies of RTO’s, which have been developed through extensive stakeholder participation, generally seek to minimize potential loss in the event of a market participant default without unnecessarily inhibiting access to the marketplace. MidAmerican Energy’s share of historical losses from defaults by other RTO market participants has not been material.

Northern Natural Gas' primary customers include regulated local distribution companies in the upper Midwest. Kern River's primary customers are major oil and gas companies or affiliates of such companies, electric generating companies, energy marketing and trading companies and natural gas distribution utilities which provide services in Utah, Nevada and California. As a general policy, collateral is not required for receivables from creditworthy customers. Customers' financial condition and creditworthiness are regularly evaluated, and historical losses have been minimal. In order to provide protection against credit risk, and as permitted by the separate terms of each of Northern Natural Gas' and Kern River's tariffs, the companies have required customers that lack creditworthiness, as defined by the tariffs, to provide cash deposits, letters of credit or other security until their creditworthiness improves.

CE Electric UK

Northern Electric and Yorkshire Electricity charge fees for the use of their electrical infrastructure levied on supply companies. The supply companies, which purchase electricity from generators and traders and sell the electricity to end-use customers, use Northern Electric's and Yorkshire Electricity's distribution networks pursuant to the multilateral "Distribution Connection and Use of System Agreement." Northern Electric's and Yorkshire Electricity's customers are concentrated in a small number of electricity supply businesses with RWE Npower PLC accounting for approximately 33% of distribution revenue in 2009. Ofgem has determined a framework which sets credit limits for each supply business based on its credit rating or payment history and requires them to provide credit cover if their value at risk (measured as being equivalent to 45 days usage) exceeds the credit limit. Acceptable credit typically is provided in the form of a parent company guarantee, letter of credit or an escrow account. Ofgem has indicated that, provided Northern Electric and Yorkshire Electricity have implemented credit control, billing and collection in line with best practice guidelines and can demonstrate compliance with the guidelines or are able to satisfactorily explain departure from the guidelines, any bad debt losses arising from supplier default will be recovered through an increase in future allowed income. Losses incurred to date have not been material.

CalEnergy Generation-Foreign

NIA's obligations under the Casecnan project agreement is CE Casecnan's sole source of operating revenue. Because of the dependence on a single customer, any material failure of the customer to fulfill its obligations under the project agreement and any material failure of the ROP to fulfill its obligation under the performance undertaking would significantly impair the ability to meet existing and future obligations, including obligations pertaining to the outstanding project debt. Total operating revenue for the Casecnan project was $147 million for the year ended December 31, 2009. The Casecnan project agreement expires in December 2021.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
MidAmerican Energy Holdings Company
Des Moines, Iowa

We have audited the accompanying consolidated balance sheets of MidAmerican Energy Holdings Company and subsidiaries (the "Company") as of December 31, 2009 and 2008, 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, 2009. Our audits also included the financial statement schedules listed in the Index at Item 15(a)(ii). These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules 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 MidAmerican Energy Holdings Company and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
March 1, 2010

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (Amounts in millions)

	As of December 31,	
	2009	**2008**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 429	$ 280
Trade receivables, net	1,308	1,310
Inventories	591	566
Derivative contracts	136	227
Investments and restricted cash and investments	83	1,589
Other current assets	546	445
Total current assets	3,093	4,417
Property, plant and equipment, net	30,936	28,454
Goodwill	5,078	5,023
Investments and restricted cash and investments	2,702	624
Regulatory assets	2,093	2,156
Derivative contracts	52	97
Other assets	730	670
Total assets	$ 44,684	$ 41,441

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

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2009	2008
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 918	$ 1,240
Accrued interest	344	340
Accrued property, income and other taxes	277	561
Derivative contracts	123	183
Short-term debt	179	836
Current portion of long-term debt	379	1,155
Other current liabilities	683	578
Total current liabilities	2,903	4,893
Regulatory liabilities	1,603	1,506
Derivative contracts	458	546
MEHC senior debt	5,371	5,121
MEHC subordinated debt	402	587
Subsidiary debt	13,600	12,533
Deferred income taxes	5,604	3,949
Other long-term liabilities	1,900	1,829
Total liabilities	31,841	30,964
Commitments and contingencies (Note 16)		
Equity:		
MEHC shareholders' equity:		
Common stock - 115 shares authorized, no par value, 75 shares issued and outstanding	-	-
Additional paid-in capital	5,453	5,455
Retained earnings	6,788	5,631
Accumulated other comprehensive income (loss), net	335	(879)
Total MEHC shareholders' equity	12,576	10,207
Noncontrolling interests	267	270
Total equity	12,843	10,477
Total liabilities and equity	$ 44,684	$ 41,441

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

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2009	**2008**	**2007**
Operating revenue:			
Energy	$ 10,167	$ 11,535	$ 10,876
Real estate	1,037	1,133	1,500
Total operating revenue	11,204	12,668	12,376
Operating costs and expenses:			
Energy:			
Cost of sales	3,904	5,170	4,649
Operating expense	2,571	2,369	2,442
Depreciation and amortization	1,238	1,110	1,130
Real estate	1,026	1,191	1,467
Total operating costs and expenses	8,739	9,840	9,688
Operating income	2,465	2,828	2,688
Other income (expense):			
Interest expense	(1,275)	(1,333)	(1,320)
Capitalized interest	41	54	54
Interest and dividend income	38	75	105
Other, net	146	1,188	112
Total other income (expense)	(1,050)	(16)	(1,049)
Income before income tax expense and equity income	1,415	2,812	1,639
Income tax expense	282	982	456
Equity income	(55)	(41)	(36)
Net income	1,188	1,871	1,219
Net income attributable to noncontrolling interests	31	21	30
Net income attributable to MEHC	$ 1,157	$ 1,850	$ 1,189

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

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2009	**2008**	**2007**
Cash flows from operating activities:			
Net income	$ 1,188	$ 1,871	$ 1,219
Adjustments to reconcile net income to net cash flows from operating activities:			
Gain on other items, net	11	(918)	(12)
Depreciation and amortization	1,256	1,129	1,150
Stock-based compensation	123	-	-
Changes in regulatory assets and liabilities	23	(23)	(16)
Provision for deferred income taxes	864	766	129
Other, net	(45)	(34)	(89)
Changes in other operating assets and liabilities, net of effects from acquisitions:			
Trade receivables and other assets	17	(58)	(265)
Derivative collateral, net	81	(120)	10
Trading securities	499	(41)	-
Contributions to pension and other postretirement benefit plans, net	(82)	(98)	(43)
Accounts payable and other liabilities	(363)	113	252
Net cash flows from operating activities	3,572	2,587	2,335
Cash flows from investing activities:			
Capital expenditures	(3,413)	(3,937)	(3,512)
Acquisitions, net of cash acquired	-	(308)	-
Purchases of available-for-sale securities	(499)	(203)	(1,641)
Proceeds from sales of available-for-sale securities	256	216	1,586
Proceeds from maturity of guaranteed investment contracts	-	393	201
Proceeds from conversion of Constellation Energy 8% preferred stock	-	418	-
Purchase of Constellation Energy 8% preferred stock	-	(1,000)	-
Proceeds from Constellation Energy 14% note	1,000	-	-
Proceeds from sale of assets	13	93	65
Other, net	(26)	(16)	51
Net cash flows from investing activities	(2,669)	(4,344)	(3,250)
Cash flows from financing activities:			
Proceeds from MEHC senior and subordinated debt	250	1,649	1,539
Repayments of MEHC senior and subordinated debt	(734)	(1,803)	(784)
Proceeds from subsidiary debt	992	1,498	2,000
Repayments of subsidiary debt	(444)	(1,077)	(549)
Net (repayments of) proceeds from MEHC revolving credit facility	(166)	216	(152)
Net (repayments of) proceeds from subsidiary short-term debt	(498)	509	(269)
Net payment of hedging instruments	-	(99)	(18)
Net purchases of common stock	(123)	-	-
Proceeds from issuances of common stock	-	-	10
Other, net	(35)	(27)	(30)
Net cash flows from financing activities	(758)	866	1,747
Effect of exchange rate changes	4	(7)	3
Net change in cash and cash equivalents	149	(898)	835
Cash and cash equivalents at beginning of period	280	1,178	343
Cash and cash equivalents at end of period	$ 429	$ 280	$ 1,178

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

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
FOR THE THREE YEARS ENDED DECEMBER 31, 2009
(Amounts in millions)

	MEHC Shareholders' Equity						
	Common		Additional Paid-in	Retained	Accumulated Other Comprehensive Income (Loss),	Noncontrolling	Total
	Shares	Stock	Capital	Earnings	net	Interests	Equity
Balance, January 1, 2007	74	$ -	$ 5,420	$ 2,598	$ (7)	$ 242	$ 8,253
Net income	-	-	-	1,189	-	30	1,219
Other comprehensive income	-	-	-	-	97	-	97
Exercise of common stock options	1	-	10	-	-		10
Tax benefit from exercise of common stock options	-	-	21	-	-		21
Contributions	-	-	-	-	-	47	47
Distributions	-	-	-	-	-	(72)	(72)
Other equity transactions	-	-	3	(5)	-	9	7
Balance, December 31, 2007	75	-	5,454	3,782	90	256	9,582
Net income	-	-	-	1,850	-	21	1,871
Other comprehensive loss	-	-	-	-	(969)	-	(969)
Contributions	-	-	-	-	-	45	45
Distributions	-	-	-	-	-	(52)	(52)
Other equity transactions	-	-	1	(1)	-	-	-
Balance, December 31, 2008	75	-	5,455	5,631	(879)	270	10,477
Net income	-	-	-	1,157	-	31	1,188
Other comprehensive income	-	-	-	-	1,214	-	1,214
Stock-based compensation	-	-	123	-	-	-	123
Exercise of common stock options	1	-	25	-	-	-	25
Common stock purchases	(1)	-	(148)	-	-	-	(148)
Contributions	-	-	-	-	-	28	28
Distributions	-	-	-	-	-	(73)	(73)
Other equity transactions	-	-	(2)	-	-	11	9
Balance, December 31, 2009	75	$ -	$ 5,453	$ 6,788	$ 335	$ 267	$ 12,843

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

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2009	**2008**	**2007**
Net income	$ 1,188	$ 1,871	$ 1,219
Other comprehensive income (loss), net of tax:			
Unrecognized amounts on retirement benefits, net of tax of $(45), $(28) and $32	(114)	(72)	38
Foreign currency translation adjustment	255	(802)	30
Fair value adjustment on cash flow hedges, net of tax of $3, $(41) and $17	7	(64)	28
Unrealized gains (losses) on marketable securities, net of tax of $709, $(20) and $1	1,066	(31)	1
Total other comprehensive income (loss), net of tax	1,214	(969)	97
Comprehensive income	2,402	902	1,316
Comprehensive income attributable to noncontrolling interests	31	21	30
Comprehensive income attributable to MEHC	$ 2,371	$ 881	$ 1,286

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

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Operations

MidAmerican Energy Holdings Company ("MEHC") is a holding company that owns subsidiaries principally engaged in energy businesses (collectively with its subsidiaries, the "Company"). MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway"). The Company is organized and managed as eight distinct platforms: PacifiCorp, MidAmerican Funding, LLC ("MidAmerican Funding") (which primarily consists of MidAmerican Energy Company ("MidAmerican Energy")), Northern Natural Gas Company ("Northern Natural Gas"), Kern River Gas Transmission Company ("Kern River"), CE Electric UK Funding Company ("CE Electric UK") (which primarily consists of Northern Electric Distribution Limited ("Northern Electric") and Yorkshire Electricity Distribution plc ("Yorkshire Electricity")), CalEnergy Generation-Foreign (which owns a majority interest in the Casecnan project in the Philippines), CalEnergy Generation-Domestic (which owns interests in independent power projects in the United States), and HomeServices of America, Inc. (collectively with its subsidiaries, "HomeServices"). Through these platforms, the Company owns and operates an electric utility company in the Western United States, a combined electric and natural gas utility company in the Midwestern United States, two interstate natural gas pipeline companies in the United States, two electricity distribution companies in Great Britain, a diversified portfolio of independent power projects and the second largest residential real estate brokerage firm in the United States.

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of MEHC and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. The Consolidated Statements of Operations include the revenue and expenses of an acquired entity from the date of acquisition. Intercompany accounts and transactions have been eliminated. Certain amounts in the prior year Consolidated Financial Statements have been reclassified to conform to the current year presentation. Such reclassifications did not impact previously reported operating income, net income attributable to MEHC or retained earnings.

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; long-lived asset recovery; goodwill impairment; accounting for contingencies, including environmental, regulatory and income tax matters; 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, MidAmerican Energy, Northern Natural Gas and Kern River (the "Domestic Regulated Businesses") prepare their financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, the Domestic Regulated Businesses are 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 regulated rates.

The Company continually evaluates the applicability of the guidance for regulated operations and assesses whether its regulatory assets and liabilities are probable of future inclusion in regulated 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 the Domestic Regulated Businesses' ability to recover their costs. Based upon this continuous assessment, the Company believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in regulated rates. The assessment reflects the current political and regulatory climate at both the state and federal levels and is subject to change in the future. If it becomes no longer probable that these costs or income will be included in regulated rates, the related regulatory assets and liabilities will be written off to operating income, refunded to customers or reflected as an adjustment to future regulated rates.

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. Market participants are assumed to be independent, knowledgeable, and able and willing to transact. 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.

Cash Equivalents and Restricted Cash and Investments

Cash equivalents consist of funds invested in commercial paper, money market accounts and in 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 investments and restricted cash and investments on the Consolidated Balance Sheets.

Investments

The Company'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.

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. Realized and unrealized gains and losses on certain trust funds related to the decommissioning of nuclear generation assets and the final reclamation of leased coal mining property are recorded as net regulatory assets or liabilities since the Company expects to recover costs for these activities through regulated rates. Trading securities are carried at fair value with realized and unrealized gains and losses recognized in earnings. Held-to-maturity securities are carried at amortized cost.

If in management's judgment a decline in the fair value of an available-for-sale or held-to-maturity 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 whether or not the Company anticipates the fair value of the investment to recover prior to the expected time of sale. 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 the Company intends to sell or expects to be required to sell the debt security before amortized cost is recovered. If the Company 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). A regulatory asset or liability is established for those investment losses or gains that are probable of inclusion in regulated rates.

The Company 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. The Company applies the equity method to investments in common stock and to other investments when such other investments possess substantially identical subordinated interests to common stock. In applying the equity method, the Company records the investment at cost and subsequently increases or decreases the investment by the Company's proportionate share of the net earnings or losses and other comprehensive income of the investee. The Company records dividends or other equity distributions as reductions in the carrying value of the investment.

Allowance for Doubtful Accounts

The allowance for doubtful accounts is based on the Company's assessment of the collectibility of payments from its customers. This assessment requires judgment regarding the ability of customers to pay the amounts owed to the Company or the outcome of any pending disputes. As of December 31, 2009 and 2008, the allowance for doubtful accounts totaled $25 million and $24 million, respectively, and is included in trade receivables, net on the Consolidated Balance Sheets.

Derivatives

The Company 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; interest rate risk; and foreign currency exchange rate risk. Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect reductions permitted under master netting arrangements with counterparties and cash collateral paid or received under such agreements. Cash collateral received from or paid to counterparties to secure derivative assets or liabilities in excess of amounts offset is included in other current assets on the Consolidated Balance Sheets.

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 are not marked-to-market and operating revenue or cost of sales is recognized on the Consolidated Statements of Operations when the contracts settle.

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

Changes in the fair value of a derivative 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. The Company discontinues hedge accounting prospectively when it has determined that a derivative 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 no longer qualifies as an effective hedge, future changes in the value of the derivative 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 are immediately recognized in earnings.

For the Company's derivatives not designated as hedging contracts, the settled amount is generally included in regulated 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 regulated rates are recorded as net regulatory assets and liabilities. For contracts not probable of inclusion in regulated rates, changes in fair value are recognized in earnings.

Inventories

Inventories consist mainly of material and supplies totaling \$311 million and \$310 million as of December 31, 2009 and 2008, respectively, and fuel, which includes coal stocks, gas in storage and fuel oil, totaling \$280 million and \$256 million as of December 31, 2009 and 2008, respectively. Inventories are stated at the lower of cost or market. The cost of materials and supplies, coal stocks and fuel oil is determined primarily using the average cost method. The cost of gas in storage is determined using either the last-in-first-out ("LIFO") or average cost method. With respect to inventories carried at LIFO cost, the replacement cost would be \$48 million and \$51 million higher as of December 31, 2009 and 2008, respectively.

Property, Plant and Equipment, Net

General

Property, plant and equipment is recorded at historical cost. The Company capitalizes all construction related material, direct labor and contract services, as well as indirect construction costs, which include capitalized interest and equity allowance for funds used during construction ("AFUDC"). The cost of major additions and betterments are capitalized, while costs for replacements, maintenance and repairs that do not improve or extend the lives of the related assets are generally charged to operating expense as incurred.

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 the Company's various regulatory authorities. Periodic depreciation studies are completed by the Domestic Regulated Businesses 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, including AROs and other costs of removal. Estimated removal costs that are recovered through approved depreciation rates, but that do not meet the requirements of a legal ARO, are reflected in the cost of removal regulatory liability on the Consolidated Balance Sheets, and as such costs are incurred, the regulatory liability is reduced.

Generally when the Company retires or sells a component of domestic 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.

The Domestic Regulated Businesses record debt and equity AFUDC, which represents the estimated costs of debt and equity funds necessary to finance the construction of domestic regulated facilities. AFUDC is capitalized as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. After construction is completed, the Company is permitted to earn a return on these costs as a component of the related asset, as well as recover these costs through depreciation expense over the useful life of the related assets.

Asset Retirement Obligations

The Company recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. The Company's AROs are primarily related to decommissioning nuclear generation assets and final reclamation of leased coal mining property. 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 expected value of the retirement obligation (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.

Impairment

The Company evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable, or the assets meet the criteria of held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated discounted present value of the expected future cash flows from using the asset. For regulated assets, any impairment charge is offset by the establishment of a regulatory asset to the extent recovery in future regulated rates is probable. For all other assets, any resulting impairment loss is reflected on the Consolidated Statements of Operations.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired in business acquisitions. The Company evaluates goodwill for impairment at least annually and completed its annual review as of October 31. Evaluating goodwill for impairment involves a two-step process. The first step is to estimate the fair value of the reporting unit. If the carrying amount of a reporting unit, including goodwill, exceeds the estimated fair value, a second step is performed. Under the second step, the identifiable assets, including identifiable intangible assets, and liabilities of the reporting unit are estimated at fair value as of the current testing date. The excess of the estimated fair value of the reporting unit over the estimated fair value of net assets establishes the implied value of goodwill. The excess of the recorded goodwill over the implied value is charged to earnings as an impairment loss. A significant amount of judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. The Company uses a variety of methods to determine fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; earnings before interest, taxes, depreciation and amortization ("EBITDA") multiples; and an appropriate discount rate. In estimating future cash flows, the Company incorporates current market information, as well as historical factors. As such, the determination of fair value incorporates significant unobservable inputs. During 2009, 2008 and 2007, the Company did not record any goodwill impairment.

The Company records goodwill adjustments for (a) the tax benefit associated with the excess of tax-deductible goodwill over the reported amount of goodwill and (b) changes to the purchase price allocation prior to the end of the allocation period, which is not to exceed one year from the acquisition date.

Revenue Recognition

Energy Businesses

Revenue from energy business customers is recognized as electricity or natural gas is delivered or services are provided. Revenue recognized includes unbilled, as well as billed, amounts. As of December 31, 2009 and 2008, unbilled revenue was $441 million and $444 million, respectively, and is included in trade receivables, net on the Consolidated Balance Sheets. Rates charged by energy businesses are established by regulators or contractual arrangements. When preliminary rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued. The Company 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.

Real Estate Commission Revenue and Related Fees

Commission revenue from real estate brokerage transactions and related amounts due to agents are recognized when a real estate transaction is closed. Title fee revenue from real estate transactions and related amounts due to the title insurer are recognized at closing.

Unamortized Debt Premiums, Discounts and Financing Costs

Premiums, discounts and financing costs incurred during the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

Foreign Currency

The accounts of foreign-based subsidiaries are measured in most instances using the local currency of the subsidiary as the functional currency. Revenue and expenses of these businesses are translated into United States dollars at the average exchange rate for the period. Assets and liabilities are translated at the exchange rate as of the end of the reporting period. Gains or losses from translating the financial statements of foreign-based operations are included in equity as a component of AOCI. Gains or losses arising from other transactions denominated in a currency other than the Company's functional currency are included on the Consolidated Statements of Operations.

Income Taxes

Berkshire Hathaway includes the Company in its United States federal income tax return. Consistent with established regulatory practice, the Company'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 other comprehensive income are charged or credited directly to other comprehensive income. 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 and MidAmerican Energy (the "Utilities") are required to pass on to their 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 $737 million and $607 million as of December 31, 2009 and 2008, respectively, and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Valuation allowances are established for certain deferred tax assets where realization is not likely. Investment tax credits are generally deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory jurisdictions.

The Company has not provided United States federal deferred income taxes on its currency translation adjustment or the cumulative earnings of international subsidiaries that have been determined by management to be reinvested indefinitely. The cumulative earnings related to ongoing operations determined to be reinvested indefinitely were approximately $1.323 billion as of December 31, 2009. Because of the availability of United States foreign tax credits, it is not practicable to determine the United States federal income tax liability that would be payable if such earnings were not reinvested indefinitely. Deferred taxes are provided for earnings of international subsidiaries when the Company plans to remit those earnings.

In determining the Company's income taxes, management is required to interpret complex tax laws and regulations, which includes consideration of regulatory implications imposed by the Company's various regulatory jurisdictions. In preparing tax returns, the Company is subject to continuous examinations by federal, state, local and foreign 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. Although the ultimate resolution of the Company's federal, state, local and foreign tax examinations is uncertain, the Company 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 affect on the Company's consolidated financial results. Assets and liabilities are established for uncertain tax positions taken or positions expected to be taken in income tax returns when such positions are judged to not meet the "more-likely-than-not" threshold based on the technical merits of the position. The Company's unrecognized tax benefits are primarily included in accrued property, income 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.

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" ("ASC Topic 820"). 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. This guidance is effective for interim and annual reporting periods beginning after December 15, 2009, 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 Company is currently evaluating the impact of adopting this guidance on its disclosures included within Notes to Consolidated Financial Statements.

In August 2009, the FASB issued ASU No. 2009-05, which amends ASC Topic 820. ASU No. 2009-05 clarifies how to measure the fair value of a liability for which a quoted price in an active market for the identical liability is not available. This guidance also clarifies that both a quoted price in an active market for the identical liability at the measurement date and the quoted price for the identical liability when traded as an asset in an active market when no adjustments to the quoted price of the asset are required represent Level 1 fair value measurements. The Company adopted this guidance as of October 1, 2009 and the adoption did not have a material impact on the Company's consolidated financial results and disclosures included within Notes to Consolidated Financial Statements.

In June 2009, the FASB issued authoritative guidance 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. This guidance is effective as of the beginning of the first annual reporting period that begins after November 15, 2009, for interim periods within that first annual reporting period and for interim and annual reporting periods thereafter, with early application prohibited. The Company is currently evaluating the impact of adopting this guidance on its consolidated financial results and disclosures included within Notes to Consolidated Financial Statements.

In April 2009, the FASB issued authoritative guidance (included in ASC Topic 320, "Investments – Debt and Equity Securities") that amends current other-than-temporary impairment guidance for debt securities to require a new other-than-temporary impairment model that shifts the focus from an entity's intent to hold the debt security until recovery to its intent, or expected requirement, to sell the debt security. In addition, this guidance expands the already required annual disclosures about other-than-temporary impairment for debt and equity securities, requires companies to include these expanded disclosures in interim financial statements and addresses whether an other-than-temporary impairment should be recognized in earnings, other comprehensive income or some combination thereof. The Company adopted this guidance as of April 1, 2009 and the adoption did not have a material impact on the Company's consolidated financial results and disclosures included within Notes to Consolidated Financial Statements.

In April 2009, the FASB issued authoritative guidance (included in ASC Topic 820) that clarifies the determination of fair value when a market is not active and if a transaction is not orderly. In addition, this guidance amends previous GAAP to require disclosures in interim and annual periods of the inputs and valuation techniques used to measure fair value and a discussion of changes in valuation techniques and related inputs, if any, during the period and defines "major categories" consistent with those described in previously existing GAAP. The Company adopted this guidance as of April 1, 2009 and the adoption did not have a material impact on the Company's consolidated financial results and disclosures included within Notes to Consolidated Financial Statements.

In December 2008, the FASB issued authoritative guidance (included in ASC Topic 715, "Compensation – Retirement Benefits") that requires enhanced disclosures about plan assets of defined benefit pension and other postretirement benefit plans to enable investors to better understand how investment allocation decisions are made and the major categories of plan assets. In addition, this guidance requires disclosure of the inputs and valuation techniques used to measure fair value and the effect of fair value measurements using significant unobservable inputs on changes in plan assets and establishes disclosure requirements for significant concentrations of risk within plan assets. The Company adopted this guidance as of December 31, 2009 and included the required disclosures within Notes to Consolidated Financial Statements. Refer to Note 14 for additional discussion.

In March 2008, the FASB issued authoritative guidance (included in ASC Topic 815, "Derivatives and Hedging") that requires enhanced disclosures about derivative contracts and hedging activities to enable investors to better understand how and why an entity uses derivative contracts and their effects on an entity's financial results. The Company adopted this guidance as of March 31, 2009 and included the required disclosures within Notes to Consolidated Financial Statements. Refer to Note 7 for additional discussion.

In December 2007, the FASB issued authoritative guidance (included in ASC Topic 810, "Consolidation") that establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. The Company adopted this guidance as of January 1, 2009. As a result, the Company has presented noncontrolling interests as a separate component of equity on the Consolidated Balance Sheets. Previously, these amounts were reported as minority interest and preferred securities of subsidiaries within the mezzanine section on the Consolidated Balance Sheets. Also, the Company has presented net income attributable to noncontrolling interests separately on the Consolidated Statements of Operations. Previously, these amounts were reported as minority interest and preferred dividends of subsidiaries on the Consolidated Statements of Operations.

(3) Property, Plant and Equipment, Net

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

	Depreciable Life	2009	2008
Regulated assets:			
Utility generation, distribution and transmission system	5-85 years	$ 35,616	$ 32,795
Interstate pipeline assets	3-67 years	5,809	5,649
		41,425	38,444
Accumulated depreciation and amortization		(13,336)	(12,456)
Regulated assets, net		28,089	25,988
Nonregulated assets:			
Independent power plants	10-30 years	677	681
Other assets	3-30 years	480	547
		1,157	1,228
Accumulated depreciation and amortization		(462)	(430)
Non-regulated assets, net		695	798
Net operating assets		28,784	26,786
Construction in progress		2,152	1,668
Property, plant and equipment, net		$ 30,936	$ 28,454

Substantially all of the construction in progress as of December 31, 2009 and 2008 relates to the construction of regulated assets.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements with other utilities, the Utilities, as tenants in common, have undivided interests in jointly owned generation and transmission facilities. The Company 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 the Company's share of the expenses of these facilities.

The amounts shown in the table below represent the Company's share in each jointly owned facility as of December 31, 2009 (dollars in millions):

	Company Share	Facility In Service	Accumulated Depreciation and Amortization	Construction In Progress
PacifiCorp:				
Jim Bridger Nos. 1-4[(1)]	67%	$ 1,031	$ 489	$ 42
Wyodak[(1)]	80	339	178	20
Hunter No. 1	94	306	155	35
Colstrip Nos. 3 and 4[(1)]	10	248	125	1
Hunter No. 2	60	194	93	24
Hermiston[(2)]	50	174	45	-
Craig Nos. 1 and 2	19	168	83	2
Hayden No. 1	25	46	23	2
Foote Creek	79	37	16	-
Hayden No. 2	13	28	15	1
Other transmission and distribution facilities	Various	84	21	29
Total PacifiCorp		2,655	1,243	156
MidAmerican Energy:				
Louisa Unit No. 1	88%	741	346	-
Walter Scott, Jr. Unit No. 3	79	517	241	9
Walter Scott, Jr. Unit No. 4	60	446	15	2
Quad Cities Unit Nos. 1 and 2	25	356	161	37
Ottumwa Unit No. 1	52	261	156	2
George Neal Unit No. 4	41	171	135	-
George Neal Unit No. 3	72	152	117	-
Transmission facilities	Various	172	49	-
Total MidAmerican Energy		2,816	1,220	50
Total		$ 5,471	$ 2,463	$ 206

(1) Includes transmission lines and substations.

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

(5) Regulatory Matters

Regulatory Assets and Liabilities

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

	Weighted Average Remaining Life	2009	2008
Deferred income taxes[1]	28 years	$ 796	$ 675
Employee benefit plans[2]	9 years	596	663
Unrealized loss on regulated derivatives[3]	7 years	371	498
Other	Various	330	320
Total		$ 2,093	$ 2,156

(1) 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 regulated rates when the temporary differences reverse.

(2) Substantially represents amounts not yet recognized as a component of net periodic benefit cost that are expected to be included in regulated rates when recognized.

(3) Amounts represent net unrealized losses related to derivative contracts included in regulated rates.

The Company had regulatory assets not earning a return or earning less than the stipulated return as of December 31, 2009 and 2008 of $1.861 billion and $1.927 billion, respectively.

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

	Weighted Average Remaining Life	2009	2008
Cost of removal accrual[1][2]	30 years	$ 1,318	$ 1,265
Asset retirement obligations	30 years	119	90
Employee benefit plans[3]	14 years	25	10
Unrealized gain on regulated derivatives	1 year	18	52
Other	Various	123	89
Total		$ 1,603	$ 1,506

(1) Amounts are deducted from rate base or otherwise accrue a carrying cost.

(2) Amounts represent estimated costs, as accrued through depreciation rates and exclusive of ARO liabilities, of removing assets in accordance with accepted regulatory practices.

(3) Represents amounts not yet recognized as a component of net periodic benefit cost that are to be returned to customers in future periods when recognized in net periodic benefit cost.

Rate Matters

Iowa Electric Revenue Sharing

The Iowa Utilities Board ("IUB") has approved a series of settlement agreements between MidAmerican Energy, the Iowa Office of Consumer Advocate ("OCA") and other intervenors, under which MidAmerican Energy has agreed not to seek a general increase in electric base rates to become effective prior to January 1, 2014, unless its Iowa jurisdictional electric return on equity for any twelve-month period covered by the applicable agreement falls below 10%, computed as prescribed in each respective agreement. As a party to the settlement agreements, the OCA has agreed not to request or support any decrease in MidAmerican Energy's Iowa electric base rates to become effective prior to January 1, 2014.

The settlement agreements also each provide that revenue associated with Iowa retail electric returns on equity above 11.75% will be shared with customers either as a credit against the cost of new generation facilities in Iowa or as a credit to customer bills. The portion shared with customers is recorded as a regulatory liability and charged to depreciation and amortization expense when accrued. When a new generation facility is placed in service, credits from the regulatory liability are applied against the cost of the facility, which reduces depreciation expense over the life of the facility. As of December 31, 2009 and 2008, no liability was accrued for revenue sharing.

Kern River Rate Case

In January 2009, the Federal Energy Regulatory Commission ("FERC") issued an order rejecting an Offer of Settlement and Stipulation ("Settlement") for the 2004 general rate case that had been filed in September 2008 and that had the support or was not opposed by a majority of Kern River's long-term shippers, finding the Settlement would result in unjust and unreasonable rates. Kern River was ordered to file compliance rates based on an allowed return on equity of 11.55%. Pursuant to the January 2009 order, Kern River made the compliance filing in March 2009, which was revised in September 2009. A request for rehearing of the FERC's January 2009 order, as well as comments and protests on Kern River's March 2009 and September 2009 compliance filings, were timely filed. In December 2009, the FERC issued an order settling Kern River's rates for the period of Kern River's current long-term contracts ("Period One rates"), including affirming its prior opinion with regard to Kern River's allowed return, while establishing that rates should be levelized for shippers that elect to continue to take service following the expiration of their current contracts ("Period Two rates"). The FERC set all other issues related to Period Two rates for settlement processes. Kern River made a compliance filing conforming its Period One rates to the FERC's order in January 2010 and then filed illustrative Period Two rates as required by the FERC's order in February 2010.

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 Utility 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.

In April 2008, the OPUC approved the recovery of $35 million, plus interest, related to the 2006 tax year. The OPUC's April 2008 order on PacifiCorp's 2006 tax report is being challenged by the Industrial Customers of Northwest Utilities, which filed a petition in May 2008 with the Oregon Court of Appeals seeking judicial review of the April 2008 order. PacifiCorp believes the outcome of these proceedings will not have a material impact on its consolidated financial results.

In October 2009, PacifiCorp filed its 2008 tax report under SB 408. PacifiCorp's filing for the 2008 tax year indicated that PacifiCorp paid $38 million more in income taxes than was collected in rates from its retail customers. In January 2010, PacifiCorp entered into a stipulation with OPUC staff and the Citizens' Utility Board of Oregon, which if approved by the OPUC, would authorize a lower recovery totaling $2 million, including interest. The OPUC has until April 2010 to issue an order. No amounts have been recorded in relation to the 2008 tax report.

(6) Fair Value Measurements

The carrying amounts of the Company's cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximate fair value because of the short-term maturity of these instruments. The Company 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 the Company 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 the Company's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Company develops these inputs based on the best information available, including its own data.

The following table presents the Company's assets and liabilities recognized on the Consolidated Balance Sheet and measured at fair value on a recurring basis as of December 31, 2009 (in millions):

	Input Levels for Fair Value Measurements				
Description	**Level 1**	**Level 2**	**Level 3**	**Other[(1)]**	**Total**
Assets[(2)]:					
Commodity derivatives	$ 3	$ 318	$ 36	$ (169)	$ 188
Investments in available-for-sale securities:					
Money market mutual funds[(3)]	376	-	-	-	376
Debt securities	70	79	46	-	195
Equity securities	2,230	8	-	-	2,238
	$ 2,679	$ 405	$ 82	$ (169)	$ 2,997
Liabilities:					
Commodity derivatives	$ (5)	$ (395)	$ (395)	$ 218	$ (577)
Interest rate derivative	-	(4)	-	-	(4)
	$ (5)	$ (399)	$ (395)	$ 218	$ (581)

(1) Primarily represents netting under master netting arrangements and a net cash collateral receivable of $49 million.

(2) Refer to Note 14 for information regarding the fair value of pension and other postretirement benefit plan assets as it is excluded from these amounts.

(3) Amounts are included in cash and cash equivalents; current investments and restricted cash and investments; and noncurrent investments and restricted cash and investments on the Consolidated Balance Sheet. The fair value of these money market mutual funds approximates cost.

The following table presents the Company's assets and liabilities recognized on the Consolidated Balance Sheet and measured at fair value on a recurring basis as of December 31, 2008 (in millions):

	Input Levels for Fair Value Measurements				
Description	**Level 1**	**Level 2**	**Level 3**	**Other[(1)]**	**Total**
Assets[(2)]:					
Commodity derivatives	$ 2	$ 549	$ 136	$ (363)	$ 324
Investments in available-for-sale securities:					
Money market mutual funds[(3)]	202	-	-	-	202
Debt securities	45	117	37	-	199
Equity securities	171	6	-	-	177
Investments in trading securities - Equity	499	-	-	-	499
	$ 919	$ 672	$ 173	$ (363)	$ 1,401
Liabilities:					
Commodity derivatives	$ (55)	$ (632)	$ (505)	$ 469	$ (723)
Interest rate derivative	-	(6)	-	-	(6)
	$ (55)	$ (638)	$ (505)	$ 469	$ (729)

(1) Primarily represents netting under master netting arrangements and a net cash collateral receivable of $129 million.

(2) Does not include investments in either pension or other postretirement benefit plan assets.

(3) Amounts are included in cash and cash equivalents; current investments and restricted cash and investments; and noncurrent investments and restricted cash and investments on the Consolidated Balance Sheet. The fair value of these money market mutual funds approximates cost.

When available, the fair value of derivative contracts is determined using unadjusted quoted prices for identical contracts on the applicable exchange in which the Company transacts. When quoted prices for identical contracts are not available, the Company uses forward price curves derived from 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 the Company. Market price quotations for certain major electricity and natural gas trading hubs are generally readily obtainable for the applicable term of the Company's outstanding derivative contracts; therefore, the Company'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. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, the Company uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on significant unobservable inputs. Refer to Note 7 for further discussion regarding the Company's risk management and hedging activities.

The Company's investments in money market mutual funds and debt and equity securities are accounted for as either available-for-sale or trading 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 fair value of the Company's investments in auction rate securities, where there is no current liquid market, is determined using pricing models based on available observable market data and the Company's judgment about the assumptions, including liquidity and nonperformance risks, which market participants would use when pricing the asset.

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

	2009		2008	
	Commodity Derivatives	Debt Securities	Commodity Derivatives	Debt Securities
Beginning balance	$ (369)	$ 37	$ (311)	$ 73
Changes included in earnings[(1)]	22	-	38	(5)
Changes in fair value recognized in other comprehensive income	-	9	-	(31)
Changes in fair value recognized in net regulatory assets	12	-	(100)	-
Purchases, sales, issuances and settlements	(2)	-	(9)	-
Net transfers into or out of Level 3	(22)	-	13	-
Ending balance	$ (359)	$ 46	$ (369)	$ 37

(1) Changes included in earnings are reported as operating revenue for commodity derivatives and other, net for investments in debt securities on the Consolidated Statements of Operations. Net unrealized gains included in earnings for the years ended December 31, 2009 and 2008, related to commodity derivatives held at December 31, 2009 and 2008, totaled $15 million and $31 million, respectively. Net realized losses included in earnings for the year ended December 31, 2008, related to investments in debt securities held at December 31, 2008, totaled $(5) million.

The Company's long-term debt is carried at cost on the Consolidated Financial Statements. The fair value of the Company'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 amount of the Company'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 amount and estimated fair value of the Company's long-term debt as of December 31 (in millions):

	2009		2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 19,752	$ 21,042	$ 19,396	$ 19,396

(7) Risk Management and Hedging Activities

The Company is exposed to the impact of market fluctuations in commodity prices, interest rates and foreign currency exchange rates. The Company is principally exposed to electricity and natural gas commodity price risk through MEHC's ownership of the Utilities as they have an obligation to serve retail customer load in their regulated service territories. MidAmerican Energy also provides nonregulated retail natural gas and electricity services in competitive markets. The Utilities' load and generation assets represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity, wholesale electricity that is purchased and sold and natural gas supply for regulated and nonregulated retail customers. Electricity and natural gas prices are subject to wide price swings as supply and demand for these commodities are impacted by, among many other unpredictable items, changing 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. Additionally, the Company is exposed to foreign currency exchange rate risk from its business operations and investments in Great Britain. The Company does not engage in a material amount of proprietary trading activities.

Each of the Company's business platforms 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, the Company 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. The Company manages its interest rate risk by limiting its exposure to variable interest rates and by monitoring market changes in interest rates. The Company may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate the Company's exposure to interest rate risk. The Company 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 the Company'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 the Company's derivative contracts, on a gross basis, and reconciles those amounts to the amounts presented on a net basis on the Consolidated Balance Sheet as of December 31, 2009 (in millions):

	Balance Sheet Locations				
	Derivative Assets		**Derivative Liabilities**		
	Current	**Noncurrent**	**Current**	**Noncurrent**	**Total**
Not Designated as Hedging Contracts[(1)(2)]:					
Commodity assets	$ 219	$ 70	$ 22	$ 31	$ 342
Commodity liabilities	(30)	(17)	(171)	(476)	(694)
Interest rate liability	-	-	-	(4)	(4)
Total	189	53	(149)	(449)	(356)
Designated as Hedging Contracts[(1)]:					
Commodity assets	5	-	7	3	15
Commodity liabilities	(4)	-	(53)	(44)	(101)
Total	1	-	(46)	(41)	(86)
Total derivatives	190	53	(195)	(490)	(442)
Cash collateral receivable (payable)	(54)	(1)	72	32	49
Total derivatives - net basis	$ 136	$ 52	$ (123)	$ (458)	$ (393)

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

(2) The majority of the Company's commodity derivatives not designated as hedging contracts are recoverable from customers in regulated rates and as of December 31, 2009, a net regulatory asset of $353 million was recorded related to the net derivative liabilities of $356 million.

Not Designated as Hedging Contracts

For the Company's commodity derivatives not designated as hedging contracts, the settled amount is generally included in regulated 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 regulated rates are recorded as net regulatory assets. The following table reconciles the beginning and ending balances of the Company'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 year ended December 31 (in millions):

	2009
Beginning balance	$ 446
Changes in fair value recognized in net regulatory assets	(119)
Gains reclassified to earnings - operating revenue	293
Losses reclassified to earnings - cost of sales	(267)
Ending balance	$ 353

For the Company'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, cost of sales and operating expense for purchase contracts and electricity and natural gas swap contracts and interest expense for the interest rate derivative. The following table summarizes the pre-tax gains (losses) included on the Consolidated Statements of Operations associated with the Company's derivative contracts not designated as hedging contracts and not recorded as a net regulatory asset or liability for the year ended December 31 (in millions):

	2009
Commodity derivatives:	
Operating revenue	$ 27
Cost of sales	(12)
Interest expense	2
Total	$ 17

Designated as Hedging Contracts

The Company uses derivative contracts accounted for as cash flow hedges to hedge electricity and natural gas commodity prices for delivery to nonregulated customers, spring operational sales, natural gas storage and other transactions. The Company's derivative contracts designated as fair value hedges were not significant as of December 31, 2009.

The following table reconciles the beginning and ending balances of the Company's accumulated other comprehensive loss (pre-tax) and summarizes pre-tax gains and losses on derivative contracts designated and qualifying as cash flow hedges recognized in other comprehensive income ("OCI"), as well as amounts reclassified to earnings during the year ended December 31, 2009 (in millions):

	Commodity Derivatives	Interest Rate Derivative	Total(1)
Beginning balance	$ 83	$ 6	$ 89
Losses (gains) recognized in OCI	99	-	99
Gains reclassified to earnings – revenue	11	-	11
Losses reclassified to earnings – cost of sales	(112)	-	(112)
Losses reclassified to earnings – interest expense	-	(6)	(6)
Ending balance	$ 81	$ -	$ 81

(1) Certain derivative contracts, principally interest rate locks, have settled and the fair value at the date of settlement remains in accumulated other comprehensive income (loss) and is amortized to earnings over the remaining life of the respective long-term debt.

Realized gains and losses on all hedges and hedge ineffectiveness are recognized in income as operating revenue, cost of sales, operating expense or interest expense depending upon the nature of the item being hedged. For the years ended December 31, 2009, 2008 and 2007, hedge ineffectiveness was insignificant. As of December 31, 2009, the Company had cash flow hedges with expiration dates extending through December 2022 and $37 million of pre-tax net unrealized losses are forecasted to be reclassified from AOCI into earnings over the next twelve months as contracts settle.

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	2009
Commodity contracts:		
Electricity sales	Megawatt hours	(20)
Natural gas purchases	Decatherms	245
Fuel purchases	Gallons	18
Interest rate derivative – variable to fixed swap	Australian dollars	59

Credit Risk

The Utilities extend unsecured credit to other utilities, energy marketers, 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.

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

MidAmerican Energy also has potential indirect credit exposure to other market participants in the regional transmission organization ("RTO") markets where it actively participates, including the Midwest Independent Transmission System Operator, Inc., PJM Interconnection, L.L.C., and the Electric Reliability Council of Texas. In the event of a default by a RTO market participant on its market-related obligations, losses are allocated among all other market participants in proportion to each participant's share of overall market activity during the period of time the loss was incurred. Transactional activities of MidAmerican Energy and other participants in organized RTO markets are governed by credit policies specified in each respective RTO's governing tariff or related business practices. Credit policies of RTO's, which have been developed through extensive stakeholder participation, generally seek to minimize potential loss in the event of a market participant default without unnecessarily inhibiting access to the marketplace. MidAmerican Energy's share of historical losses from defaults by other RTO market participants has not been material.

Collateral and Contingent Features

In accordance with industry practice, certain derivative contracts contain provisions that require MEHC's subsidiaries, principally the Utilities, to maintain specific credit ratings from one or more of the major credit rating agencies on their 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 the subsidiary's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2009, these subsidiary's credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of the Company's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $473 million as of December 31, 2009, for which the Company had posted collateral of $99 million. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of December 31, 2009, the Company would have been required to post $237 million of additional collateral. The Company's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings or other factors.

(8) Investments and Restricted Cash and Investments

Investments and restricted cash and investments consist of the following as of December 31 (in millions):

	2009	2008
Investments:		
BYD common stock	$ 1,986	$ -
Constellation Energy 14% Senior Notes	-	1,000
Constellation Energy common stock	-	499
Rabbi trusts	268	245
Other	97	74
Total investments	2,351	1,818
Restricted cash and investments:		
Nuclear decommissioning trust funds	264	231
Mine reclamation trust funds	79	79
Other	91	85
Total restricted cash and investments	434	395
Total investments and restricted cash and investments	2,785	2,213
Less current portion	(83)	(1,589)
Noncurrent portion	$ 2,702	$ 624

Investments and restricted cash and investments that management does not intend to use in current operations are presented as noncurrent on the Consolidated Balance Sheets. Gross unrealized and realized gains and losses of investments are not material as of December 31, 2009 and 2008 and for the three years in the period ended December 31, 2009, respectively, except as discussed below related to the BYD Company Limited ("BYD") and Constellation Energy Group, Inc. ("Constellation Energy") common stock investments.

In September 2008, MEHC reached a definitive agreement with BYD to purchase 225 million shares, representing approximately a 10% interest in BYD, at a price of Hong Kong ("HK") $8 per share or HK$1.8 billion ($232 million). Established in 1995, BYD is a Hong Kong listed company with two main businesses: technology, including rechargeable batteries, chargers and cell phone design and assembly, and automobiles. BYD has seven production bases in Guangdong, Beijing, Shanghai and Xi'an and has offices in the United States, Europe, Japan, South Korea, India, Taiwan, Hong Kong and other regions. BYD has over 130,000 employees. The purchase was approved by an affirmative vote of the holders of two-thirds of the outstanding shares of BYD at an extraordinary general meeting held on December 3, 2008. The investment was made on July 30, 2009. MEHC's investment in BYD is accounted for as an available-for-sale security with changes in fair value recognized in AOCI. The fair value of $1.986 billion as of December 31, 2009 compared to the acquisition cost of $232 million resulted in a pre-tax unrealized gain of $1.754 billion as of December 31, 2009.

On September 19, 2008, MEHC, Constellation Energy and MEHC Merger Sub Inc. signed an Agreement and Plan of Merger (the "Merger Agreement"), under which Constellation Energy would have become an indirect wholly-owned subsidiary of MEHC. In addition, the Company purchased a $1 billion investment in Constellation Energy 8% Preferred Stock. On December 17, 2008, MEHC and Constellation Energy entered into a termination agreement, pursuant to which, among other things, the parties agreed to terminate the Merger Agreement. As a result of the termination, the Company received $175 million, which is recorded in other, net on the Consolidated Statement of Operations and converted the $1 billion of Constellation Energy 8% Preferred Stock into $1 billion of 14% Senior Notes due from Constellation Energy, 19.9 million shares of Constellation Energy common stock and cash totaling $418 million. The 19.9 million common shares had a fair value of $499 million as of December 31, 2008, which included $41 million of unrealized holding gains recognized in other, net on the Consolidated Statement of Operations. During the year ended December 31, 2009, the Company sold 19.9 million shares of Constellation Energy common stock for $536 million, or an average price of $26.93 per share, and recognized gains totaling $37 million, which are included in other, net on the Consolidated Statements of Operations. The investment in the 14% Senior Notes was classified as held to maturity and was reported at cost, which approximates fair value as of December 31, 2008. On January 12, 2009, the Company received $1 billion, plus accrued interest, in full satisfaction of the 14% Senior Notes from Constellation Energy.

Rabbi trusts hold corporate-owned life insurance on certain key executives and directors. The Rabbi trusts were established to hold investments used to fund the obligations of various nonqualified executive and director compensation plans and to pay the costs of the trusts. The amount represents the cash surrender value of all of the policies included in the Rabbi trusts, net of amounts borrowed against the cash surrender value.

MidAmerican Energy has established trusts for the investment of funds for decommissioning the Quad Cities Nuclear Station Units 1 and 2. These investments in debt and equity securities are classified as available-for-sale and are reported at fair value. Funds are invested in the trust in accordance with applicable federal investment guidelines and are restricted for use as reimbursement for costs of decommissioning the Quad Cities Station. As of December 31, 2009, 57% of the fair value of the trusts' funds was invested in domestic common equity securities, 11% in domestic corporate debt securities and the remainder in investment grade municipal and United States government securities. As of December 31, 2008, 46% of the fair value of the trusts' funds was invested in domestic common equity securities, 12% in domestic corporate debt securities and the remainder in investment grade municipal and United States government securities.

PacifiCorp has established a trust for the investment of funds for final reclamation of a leased coal mining property. These investments in debt and equity securities are classified as available-for-sale and are reported at fair value. Amounts funded are based on estimated future reclamation costs and estimated future coal deliveries. As of December 31, 2009 and 2008, 57% and 46%, respectively, of the fair value of the trust's funds was invested in equity securities with the remainder invested in debt securities.

The Company has interest bearing auction rate securities with a par value of $73 million and remaining maturities of 7 to 27 years. These securities have historically provided liquidity through an auction process that reset the applicable interest rate at predetermined calendar intervals, usually every 28 days or less. The securities held have experienced multiple failed auctions and the failures resulted in the interest rate on these investments resetting at higher levels. Interest has been paid on the scheduled auction dates. The Company considers the securities to be temporarily impaired, except for an other-than-temporary decline in the fair value of $5 million recorded in the fourth quarter of 2008, and has recorded unrealized losses on the securities of $22 million and $31 million, before tax, in AOCI as of December 31, 2009 and 2008, respectively. The Company does not intend to sell or expect to be required to sell the securities until the remaining principal investment is collected.

(9) Short-Term Debt and Revolving Credit Facilities

The following table summarizes MEHC's and its subsidiaries' availability under their revolving credit facilities as of December 31, 2009 (in millions):

	MEHC	PacifiCorp	MidAmerican Funding	CE Electric UK	Home-Services	Total[1]
Available revolving credit facilities	$ 585	$ 1,395	$ 654	$ 161	$ 125	$ 2,920
Less:						
Short-term borrowings and issuances of commercial paper	(50)	-	-	(129)	-	(179)
Tax-exempt bond support, letters of credit and other	(42)	(258)	(195)	-	-	(495)
Net revolving credit facilities available	$ 493	$ 1,137	$ 459	$ 32	$ 125	$ 2,246

(1) The above table does not include unused revolving credit facilities and letters of credit for investments that are accounted for under the equity method.

MEHC

MEHC has an unsecured credit facility with $585 million available through July 2011 and then reducing to $479 million through July 2013. The credit facility has a variable interest rate based on the London Interbank Offered Rate ("LIBOR") plus a spread, which varies based on MEHC's credit ratings for its senior unsecured long-term debt securities, or a base rate, at MEHC's option. This facility is for general corporate purposes and also supports letters of credit for the benefit of certain subsidiaries and affiliates. As of December 31, 2009, MEHC had $50 million of borrowings outstanding under its credit facilities at an average rate of 0.445% and had letters of credit issued under the credit agreements totaling $42 million. Additionally, as of December 31, 2008, MEHC had available a $250 million unsecured credit facility that was terminated by the Company in October 2009. As of December 31, 2008, MEHC had $216 million of borrowings outstanding under its credit facilities at an average rate of 3.05% and had letters of credit issued under the credit agreements totaling $43 million. Each revolving credit agreement requires that MEHC's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.70 to 1.0 as of the last day of any quarter.

PacifiCorp

PacifiCorp has a $635 million unsecured credit facility expiring in October 2012 and an unsecured credit facility with $760 million available through July 2011 and then reducing to $630 million through 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 its unenhanced variable-rate tax-exempt bond obligations. As of December 31, 2009, PacifiCorp had letters of credit issued under the credit agreements totaling $220 million to support variable-rate tax-exempt bond obligations and had no borrowings outstanding under its credit facilities. In addition, the credit facilities supported $38 million of unenhanced variable-rate tax-exempt bond obligations outstanding as of December 31, 2009. As of December 31, 2008, PacifiCorp had letters of credit issued under the credit agreements totaling $220 million to support variable-rate tax-exempt bond obligations and had no borrowings outstanding under its credit facilities. In addition, the credit facilities supported $85 million of commercial paper borrowings, at an average rate of 0.95%, and $38 million of unenhanced variable-rate tax-exempt bond obligations outstanding as of December 31, 2008. Each revolving credit agreement requires that PacifiCorp's ratio of consolidated debt, including current maturities, to total capitalization at no time exceed 0.65 to 1.0.

MidAmerican Funding

MidAmerican Energy has an unsecured credit facility with $645 million available through July 2012 and then reducing to $530 million through July 2013, which supports MidAmerican Energy's commercial paper program and its variable-rate tax-exempt bond obligations. The facility has a variable interest rate based on LIBOR plus a spread that varies based on MidAmerican Energy's credit ratings for its senior unsecured long-term debt securities, or a base rate, at MidAmerican Energy's option. In addition, MidAmerican Energy has a $5 million unsecured credit facility, which expires in June 2010 and has a variable interest rate based on LIBOR plus a spread. As of December 31, 2009, MidAmerican Energy had no borrowings outstanding under this credit facility, had no commercial paper borrowings outstanding and had $195 million of the revolving credit facility reserved to support the variable-rate tax-exempt bond obligations. Additionally, as of December 31, 2008, MidAmerican Energy had available a $250 million unsecured credit facility that was terminated by the Company in September 2009. As of December 31, 2008, MidAmerican Energy had no borrowings outstanding under its credit facilities, had issued $457 million of commercial paper borrowings at an average rate of 1.13% and had $195 million of the credit facility reserved to support the variable-rate tax-exempt bond obligations. The revolving credit agreement requires that MidAmerican Energy's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of any quarter.

MHC, Inc., a direct wholly-owned subsidiary of MidAmerican Funding, has a $4 million unsecured credit facility, which expires in June 2010 and has a variable interest rate based on LIBOR plus a spread. As of December 31, 2009 and 2008, there were no borrowings outstanding under this credit facility.

CE Electric UK

CE Electric UK has a £100 million unsecured credit facility expiring in April 2010. The facility has a variable interest rate based on sterling LIBOR plus a spread that varies based on its credit ratings. As of December 31, 2009 and 2008, CE Electric UK had $129 million, at an interest rate of 0.78%, and $78 million, at an interest rate of 2.40%, respectively, of borrowings outstanding under its credit facility. The revolving credit agreement requires that CE Electric UK's ratio of consolidated senior net debt to regulated asset value, including current maturities, not exceed 0.8 to 1.0 at CE Electric UK and 0.65 to 1.0 at Northern Electric and Yorkshire Electricity as of June 30 and December 31. Additionally, CE Electric UK's interest coverage ratio shall not be less than 2.5 to 1.0.

HomeServices

HomeServices has a $125 million unsecured credit facility expiring in December 2010. The facility has a variable interest rate based on the prime lending rate or LIBOR, at HomeServices' option, plus a spread that varies based on HomeServices' total debt ratio. There were no borrowings outstanding under the facility as of December 31, 2009 and 2008. The revolving credit agreement requires that HomeServices' ratio of consolidated total debt to EBITDA not exceed 3.0 to 1.0 at the end of any fiscal quarter and its ratio of EBITDA to interest cannot be less than 2.5 to 1.0 at the end of any fiscal quarter.

(10) MEHC Senior Debt

MEHC senior debt represents unsecured senior obligations of MEHC and consists of the following, including fair value adjustments and unamortized premiums and discounts, as of December 31 (in millions):

	Par Value	2009	2008
3.15% Senior Notes, due 2012	$ 250	$ 250	$ -
5.875% Senior Notes, due 2012	500	500	500
5.00% Senior Notes, due 2014	250	250	250
5.75% Senior Notes, due 2018	650	649	649
8.48% Senior Notes, due 2028	475	484	484
6.125% Senior Notes, due 2036	1,700	1,699	1,699
5.95% Senior Notes, due 2037	550	547	547
6.50% Senior Notes, due 2037	1,000	992	992
Total MEHC Senior Debt	$ 5,375	$ 5,371	$ 5,121

(11) MEHC Subordinated Debt

MEHC subordinated debt consists of the following, including fair value adjustments, as of December 31 (in millions):

	Par Value	2009	2008
CalEnergy Capital Trust II-6.25%, due 2012	$ 92	$ 88	$ 86
CalEnergy Capital Trust III-6.5%, due 2027	191	149	148
MidAmerican Capital Trust I-11%, due 2010	45	45	136
MidAmerican Capital Trust II-11%, due 2012	108	108	151
MidAmerican Capital Trust III-11%, due 2011	200	200	300
MidAmerican Capital Trust IV-11%, due 2015(1)	-	-	500
Total MEHC Subordinated Debt	$ 636	$ 590	$ 1,321

(1) MEHC repaid $500 million on each of December 22, 2008 and January 13, 2009, to affiliates of Berkshire Hathaway in full satisfaction of the aggregate amount owed pursuant to the $1 billion of 11% mandatory redeemable trust preferred securities issued by MidAmerican Capital Trust IV to affiliates of Berkshire Hathaway on September 19, 2008.

The Capital Trusts were formed for the purpose of issuing trust preferred securities to holders and investing the proceeds received in subordinated debt issued by MEHC. The terms of the MEHC subordinated debt are substantially identical to those of the trust preferred securities. The MEHC subordinated debt associated with the CalEnergy Trusts is callable at the option of MEHC at any time at par value plus accrued interest. The MEHC subordinated debt associated with the MidAmerican Capital Trusts is not callable by MEHC except upon the limited occurrence of specified events. Distributions on the MEHC subordinated debt are payable either quarterly or semi-annually, depending on the issue, in arrears, and can be deferred at the option of MEHC for up to five years. During the deferral period, interest continues to accrue on the CalEnergy Capital Trusts at their stated rates, while interest accrues on the MidAmerican Capital Trusts at 13% per annum. The CalEnergy Capital Trust preferred securities are convertible any time into cash at the option of the holder for an aggregate amount of $216 million.

The MidAmerican Capital Trust preferred securities are held by Berkshire Hathaway and its affiliates, which are prohibited from transferring the securities to non-affiliated persons absent an event of default. Interest expense to Berkshire Hathaway for the years ended December 31, 2009, 2008 and 2007 was $58 million, $111 million and $108 million, respectively. Interest expense on the CalEnergy Capital Trusts for the years ended December 31, 2009, 2008 and 2007 was $22 million, $24 million and $28 million, respectively.

The MEHC subordinated debt is subordinated to all senior indebtedness of MEHC and is subject to certain covenants, events of default and optional and mandatory redemption provisions, all described in the indenture. Upon involuntary liquidation, the holder is entitled to par value plus any distributions in arrears. MEHC has agreed to pay to the holders of the trust preferred securities, to the extent that the applicable Trust has funds available to make such payments, quarterly distributions, redemption payments and liquidation payments on the trust preferred securities.

(12) Subsidiary Debt

MEHC's direct and indirect subsidiaries are organized as legal entities separate and apart from MEHC and its other subsidiaries. Pursuant to separate financing agreements, substantially all or most of the properties of each of the Company's subsidiaries (except CE Electric UK, MidAmerican Energy and Northern Natural Gas) are pledged or encumbered to support or otherwise provide the security for their own subsidiary debt. It should not be assumed that the assets of any subsidiary will be available to satisfy MEHC's obligations or the obligations of its other subsidiaries. However, unrestricted cash or other assets which are available for distribution may, subject to applicable law, regulatory commitments and the terms of financing and ring-fencing arrangements for such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to MEHC or affiliates thereof. The long-term debt of subsidiaries may include provisions that allow MEHC's subsidiaries to redeem it in whole or in part at any time. These provisions generally include make-whole premiums.

Distributions at these separate legal entities are limited by various covenants including, among others, leverage ratios, interest coverage ratios and debt service coverage ratios. As of December 31, 2009, all subsidiaries were in compliance with their covenants. However, Cordova Energy's 537 MW gas-fired generating facility in the Quad Cities, Illinois area is currently prohibited from making distributions by the terms of its indenture due to its failure to meet its debt service coverage ratio requirement.

Long-term debt of subsidiaries consists of the following, including fair value adjustments and unamortized premiums and discounts, as of December 31 (in millions):

	Par Value	2009	2008
PacifiCorp	$ 6,541	$ 6,526	$ 5,568
MidAmerican Funding	525	484	657
MidAmerican Energy	2,872	2,865	2,865
Northern Natural Gas	1,000	1,000	1,000
Kern River	869	869	944
CE Electric UK	1,732	1,853	1,700
CE Casecnan	17	17	30
Cordova Funding	179	177	183
HomeServices	-	-	7
Total Subsidiary Debt	$ 13,735	$ 13,791	$ 12,954

PacifiCorp

PacifiCorp's long-term debt consists of the following, including unamortized premiums and discounts, as of December 31 (dollars in millions):

	Par Value	2009	2008
First mortgage bonds:			
5.0% to 9.2%, due through 2014	$ 1,047	$ 1,047	$ 1,185
5.5% to 8.7%, due 2015 to 2019	862	858	511
6.7% to 8.5%, due 2021 to 2023	324	324	324
6.7% due 2026	100	100	100
5.9% to 7.7%, due 2031 to 2034	500	499	499
5.3% to 6.4%, due 2035 to 2039	2,800	2,790	2,145
Tax-exempt obligations:			
Variable-rate series (2009-0.18% to 0.34%, 2008-0.7% to 2.6%):			
Due 2013, secured by first mortgage bonds	41	41	41
Due 2014 to 2025	325	325	325
Due 2024, secured by first mortgage bonds	176	176	176
Variable-rate series, due 2014 to 2025[(1)]	113	113	113
5.6% to 5.7%, due 2021 to 2023, secured by first mortgage bonds	71	71	71
6.2%, due 2030	13	13	13
Capital lease obligations – 8.8% to 14.8%, due through 2036	169	169	65
Total PacifiCorp	$ 6,541	$ 6,526	$ 5,568

(1) Interest rates currently fixed for a term at 3.4% to 4.1%, with $45 million and $68 million scheduled to reset in 2010 and 2013, respectively.

As of December 31, 2009, PacifiCorp had letters of credit available to provide credit enhancement and liquidity support for its variable-rate tax-exempt bond obligations totaling $517 million, of which $504 million is supporting principal payments and $13 million is supporting interest payments. These committed bank arrangements were fully available at December 31, 2009 and expire periodically through May 2012.

MidAmerican Funding

MidAmerican Funding's long-term debt consists of the following, including fair value adjustments, as of December 31 (dollars in millions):

	Par Value	2009	2008
6.339% Senior Notes, due 2009	$ -	$ -	$ 174
6.75% Senior Notes, due 2011	200	200	200
6.927% Senior Bonds, due 2029	325	284	283
Total MidAmerican Funding	$ 525	$ 484	$ 657

MidAmerican Energy

MidAmerican Energy's mortgage bonds, pollution control revenue obligations and notes consist of the following, including unamortized premiums and discounts, as of December 31 (dollars in millions):

	Par Value	2009	2008
Tax-exempt obligations:			
Variable-rate series (2009-0.4%, 2008-1.14%), due 2016-2038	$ 195	$ 195	$ 195
Notes:			
5.65% Series, due 2012	400	400	400
5.125% Series, due 2013	275	275	275
4.65% Series, due 2014	350	350	350
5.95% Series, due 2017	250	249	249
5.3% Series, due 2018	350	349	349
6.75% Series, due 2031	400	396	396
5.75% Series, due 2035	300	300	300
5.80% Series, due 2036	350	349	349
Other	2	2	2
Total MidAmerican Energy	$ 2,872	$ 2,865	$ 2,865

Northern Natural Gas

Northern Natural Gas' long-term debt consists of the following, including unamortized premiums and discounts, as of December 31 (dollars in millions):

	Par Value	2009	2008
7.00% Senior Notes, due 2011	$ 250	$ 250	$ 250
5.375% Senior Notes, due 2012	300	300	300
5.125% Senior Notes, due 2015	100	100	100
5.75% Senior Notes, due 2018	200	200	200
5.80% Senior Notes, due 2037	150	150	150
Total Northern Natural Gas	$ 1,000	$ 1,000	$ 1,000

Kern River

Kern River's long-term debt, which is due in monthly installments, consists of the following as of December 31 (dollars in millions):

	Par Value	2009	2008
6.676% Senior Notes, due 2016	$ 309	$ 309	$ 335
4.893% Senior Notes, due 2018	560	560	609
Total Kern River	$ 869	$ 869	$ 944

Kern River provides a debt service reserve letter of credit in amounts equal to the next six months of principal and interest payments due on the loans which were equal to $64 million as of December 31, 2009 and 2008.

CE Electric UK

CE Electric UK and its subsidiaries' long-term debt consists of the following, including fair value adjustments and unamortized premiums and discounts, as of December 31 (dollars in millions):

	Par Value[(1)]	2009	2008
8.875% Bearer Bonds, due 2020	$ 162	$ 191	$ 178
9.25% Eurobonds, due 2020	323	380	349
7.25% Sterling Bonds, due 2022	323	349	320
7.25% Eurobonds, due 2028	300	314	285
5.125% Bonds, due 2035	323	319	289
5.125% Bonds, due 2035	242	241	218
CE Gas Credit Facility, 4.78% and 4.84%, due 2012	59	59	61
Total CE Electric UK	$ 1,732	$ 1,853	$ 1,700

(1) The par values for these debt instruments are denominated in sterling and have been converted to United States dollars at the applicable exchange rate.

Cordova Funding

Cordova Funding Corporation ("Cordova Funding") has senior secured bonds with interest rates ranging from 8.48% to 9.07%, due in semi-annual installments through 2019, having a total par value of $179 million. The outstanding balance of these bonds, including fair value adjustments, as of December 31, 2009 and 2008 was $177 million and $183 million, respectively.

MEHC has issued a limited guarantee of a specified portion of the final scheduled principal payment on December 15, 2019, on the Cordova Funding senior secured bonds in an amount up to a maximum of $37 million.

Annual Repayments of Long-Term Debt

The annual repayments of MEHC and subsidiary debt for the years beginning January 1, 2010 and thereafter, excluding fair value adjustments and unamortized premiums and discounts, are as follows (in millions):

	2010	2011	2012	2013	2014	2015 and Thereafter	Total
MEHC senior debt	$ -	$ -	$ 750	$ -	$ 250	$ 4,375	$ 5,375
MEHC subordinated debt	188	143	114	-	-	191	636
PacifiCorp	27	600	33	284	275	5,322	6,541
MidAmerican Funding	-	200	-	-	-	325	525
MidAmerican Energy	-	1	400	275	350	1,846	2,872
Northern Natural Gas	-	250	300	-	-	450	1,000
Kern River	79	81	81	80	81	467	869
CE Electric UK	59	-	-	-	-	1,673	1,732
CE Casecnan	17	-	-	-	-	-	17
Cordova Funding	9	9	10	12	14	125	179
Totals	$ 379	$ 1,284	$ 1,688	$ 651	$ 970	$ 14,774	$ 19,746

(13) Asset Retirement Obligations

The Company 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 expected work.

The Company 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 regulatory removal cost liability established via approved depreciation rates.

The change in the balance of the total ARO liability, which is included in other current liabilities and other long-term liabilities on the Consolidated Balance Sheets, is summarized as follows (in millions):

	2009	2008
Balance, January 1	$ 445	$ 422
Change in estimated costs	29	19
Additions	3	8
Retirements	(40)	(28)
Accretion	26	24
Balance, December 31	$ 463	$ 445
Reflected as:		
Other current liabilities	$ 22	$ 27
Other long-term liabilities	441	418
	$ 463	$ 445
Investment trust funds	$ 343	$ 310

The Company's most significant ARO liabilities relate to the decommissioning of nuclear power plants at MidAmerican Energy and the reclamation of mine property at PacifiCorp.

The Nuclear Regulatory Commission ("NRC") regulates the decommissioning of nuclear power plants, which includes the planning and funding for the decommissioning. In accordance with these regulations, MidAmerican Energy submits a biennial report to the NRC providing reasonable assurance that funds will be available to pay for its share of the Quad Cities Station decommissioning. The decommissioning costs are included in base rates in MidAmerican Energy's Iowa tariffs. MidAmerican Energy's share of estimated Quad Cities Station decommissioning costs was $168 million and $159 million as of December 31, 2009 and 2008, respectively, and is the asset retirement obligation for the Quad Cities Station. MidAmerican Energy has established trusts for the investment of decommissioning funds. The fair value of the assets held in the trusts was $264 million and $231 million as of December 31, 2009 and 2008, respectively, and is reflected in noncurrent investments and restricted cash and investments on the Consolidated Balance Sheets.

PacifiCorp's ARO liabilities consist principally of coal mine reclamation obligations for its Jim Bridger mine that were $79 million and $84 million as of December 31, 2009 and 2008, respectively. The fair value of the assets held in trusts was $79 million as of December 31, 2009 and 2008 and is reflected in both current and noncurrent investments and restricted cash and investments, including the minority interest joint-owner portions, on the Consolidated Balance Sheets.

Certain of the Company's decommissioning and reclamation obligations relate to jointly-owned facilities and mine sites, and as such, each subsidiary 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, the respective subsidiary may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. The Company's estimated share of the decommissioning and reclamation obligations are recorded as ARO liabilities.

In addition to the ARO liabilities, the Company has accrued for the cost of removing other electric and gas assets through its depreciation rates, in accordance with accepted regulatory practices. These accruals are reflected as regulatory liabilities and total $1.318 billion and $1.265 billion as of December 31, 2009 and 2008, respectively.

(14) Employee Benefit Plans

Domestic Operations

PacifiCorp sponsors defined benefit pension plans that cover the majority of its employees. PacifiCorp's pension plans include a noncontributory defined benefit pension plan, a supplemental executive retirement plan ("SERP") and certain joint trust union plans to which PacifiCorp contributes on behalf of certain bargaining units. MidAmerican Energy sponsors defined benefit pension plans covering substantially all employees of MEHC and its domestic energy subsidiaries other than PacifiCorp. MidAmerican Energy's pension plans include a noncontributory defined benefit pension plan and a SERP. The Utilities also provide certain postretirement healthcare and life insurance benefits through various plans for eligible retirees.

Changes to the Company's domestic pension and other postretirement benefit plans include the following:

- In August 2008, non-union employee participants in the PacifiCorp-sponsored and MidAmerican Energy-sponsored noncontributory defined benefit pension plans were offered the option to continue to receive pay credits in their current cash balance pension plan or receive equivalent fixed contributions to the PacifiCorp-sponsored and MidAmerican Energy-sponsored 401(k) plans. The election was effective January 1, 2009, and resulted in the recognition of a $43 million curtailment gain. The Company recorded $41 million of the curtailment gain as a reduction to regulatory assets as of December 31, 2008, representing the amount to be returned to customers in rates.

- Non-union employees hired on or after January 1, 2008 are not eligible to participate in the PacifiCorp-sponsored or MidAmerican Energy-sponsored noncontributory defined benefit pension plans. These non-union employees are eligible to receive enhanced benefits under the PacifiCorp-sponsored and MidAmerican Energy-sponsored 401(k) plans.

- Certain union employees hired on or after dates specified in their union contracts are not eligible to participate in the PacifiCorp-sponsored or MidAmerican Energy-sponsored noncontributory defined benefit pension plans. During the past three years, several unions have elected to cease participation in the PacifiCorp-sponsored or MidAmerican Energy-sponsored noncontributory defined benefit pension plans. As a result of these elections, the benefits for these union employees have been frozen and they are eligible to receive enhanced benefits under the PacifiCorp-sponsored and MidAmerican Energy-sponsored 401(k) plans.

PacifiCorp adopted the measurement date provisions included in the authoritative guidance for retirement benefits at December 31, 2008, which requires that an employer measure plan assets and benefit obligations at the end of the employer's fiscal year. Effective December 31, 2008, PacifiCorp changed its measurement date from September 30 to December 31 and recorded a $14 million transitional adjustment, which included a $12 million increase to regulatory assets for the portion considered probable of inclusion in regulated rates and a $2 million pre-tax reduction in retained earnings for the portion not considered probable of inclusion in regulated rates. Also as a result of this transitional adjustment, PacifiCorp's pension and other postretirement liabilities increased by $8 million and regulatory assets decreased by $6 million.

Net Periodic Benefit Cost

For purposes of calculating the expected return on pension 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		
	2009	**2008**	**2007**	**2009**	**2008**	**2007**
Service cost	$ 35	$ 53	$ 55	$ 9	$ 12	$ 14
Interest cost	113	108	111	43	47	47
Expected return on plan assets	(113)	(117)	(112)	(41)	(43)	(40)
Net amortization	-	8	28	13	16	21
Curtailment gains	-	(2)	-	-	-	-
Net periodic benefit cost	$ 35	$ 50	$ 82	$ 24	$ 32	$ 42

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	
	2009	**2008**	**2009**	**2008**
Plan assets at fair value, beginning of year	$ 1,147	$ 1,638	$ 456	$ 603
Employer contributions	61	76	32	51
Participant contributions	-	-	18	24
Actual return on plan assets	253	(395)	105	(154)
Benefits paid	(139)	(172)	(57)	(68)
Plan assets at fair value, end of year	$ 1,322	$ 1,147	$ 554	$ 456

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

	Pension		Other Postretirement	
	2009	**2008**	**2009**	**2008**
Benefit obligation, beginning of year	$ 1,745	$ 1,813	$ 717	$ 793
Service cost(1)	35	60	9	14
Interest cost(1)	113	124	43	55
Participant contributions	-	-	18	24
Plan amendments	5	(7)	(45)	(13)
Curtailments	(12)	(18)	-	-
Actuarial loss (gain)	140	(55)	58	(92)
Benefits paid, net of Medicare subsidy	(139)	(172)	(54)	(64)
Benefit obligation, end of year	$ 1,887	$ 1,745	$ 746	$ 717
Accumulated benefit obligation, end of year	$ 1,836	$ 1,675		

(1) Included in the pension and other postretirement liabilities increase in connection with PacifiCorp's measurement date change in 2008 was additional service cost of $7 million and $2 million, respectively, and additional interest cost of $16 million and $8 million for the pension and other postretirement benefit plans, respectively.

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	
	2009	**2008**	**2009**	**2008**
Plan assets at fair value, end of year	$ 1,322	$ 1,147	$ 554	$ 456
Less – Benefit obligations, end of year	1,887	1,745	746	717
Funded status	$ (565)	$ (598)	$ (192)	$ (261)
Amounts recognized on the Consolidated Balance Sheets:				
Other current assets	$ -	$ -	$ 3	$ 1
Other current liabilities	(12)	(12)	-	-
Other long-term liabilities	(553)	(586)	(195)	(262)
Amounts recognized	$ (565)	$ (598)	$ (192)	$ (261)

The SERPs have no plan assets; however the Company has Rabbi trusts that hold corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERPs. The cash surrender value of all of the policies included in the Rabbi trusts, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was $155 million and $140 million as of December 31, 2009 and 2008, 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 obligations related to the SERPs was $157 million and $148 million as of December 31, 2009 and 2008, 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	
	2009	**2008**	**2009**	**2008**
Amounts not yet recognized as components of net periodic benefit cost:				
Net loss	$ 522	$ 550	$ 174	$ 182
Prior service credit	(53)	(64)	(40)	(2)
Net transition obligation	-	-	30	47
Regulatory deferrals[(1)]	(27)	(37)	5	6
Total	$ 442	$ 449	$ 169	$ 233

(1) Consists of amounts related to the portion of the curtailment gains and the measurement date change transitional adjustment that are considered probable of inclusion in regulated rates.

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2009 and 2008 is as follows (in millions):

	Regulatory Asset	Regulatory Liability	Accumulated Other Comprehensive Loss	Total
Pension				
Balance, January 1, 2008	$ 146	$ (148)	$ 4	$ 2
Net (gain) loss arising during the year	326	148	(1)	473
Prior service credit arising during the year	(7)	-	-	(7)
Curtailment gains	(15)	-	-	(15)
Measurement date change	6	-	-	6
Net amortization[1]	(9)	-	(1)	(10)
Total	301	148	(2)	447
Balance, December 31, 2008	447	-	2	449
Net (gain) loss arising during the year	-	(19)	7	(12)
Prior service cost arising during the year	(1)	6	-	5
Net amortization	(2)	4	(2)	-
Total	(3)	(9)	5	(7)
Balance, December 31, 2009	$ 444	$ (9)	$ 7	$ 442

	Regulatory Asset	Regulatory Liability	Deferred Income Taxes	Accumulated Other Comprehensive Loss	Total
Other Postretirement					
Balance, January 1, 2008	$ 115	$ (25)	$ 56	$ -	$ 146
Net (gain) loss arising during the year	116	15	(18)	1	114
Prior service credit arising during the year	(13)	-	-	-	(13)
Measurement date change	6	-	-	-	6
Net amortization[1]	(20)	-	-	-	(20)
Total	89	15	(18)	1	87
Balance, December 31, 2008	204	(10)	38	1	233
Net (gain) loss arising during the year	(6)	(2)	1	-	(7)
Prior service credit arising during the year	(30)	(4)	(6)	(1)	(41)
Transition obligation credit arising during the year	(3)	-	-	-	(3)
Net amortization	(13)	-	-	-	(13)
Total	(52)	(6)	(5)	(1)	(64)
Balance, December 31, 2009	$ 152	$ (16)	$ 33	$ -	$ 169

(1) Included in the regulatory assets decrease in connection with PacifiCorp's measurement date change in 2008 was additional amortization of $2 million and $4 million for the pension and other postretirement benefit plans, respectively.

The net loss, prior service credit, net transition obligation and regulatory deferrals that will be amortized in 2010 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	$ 33	$ (7)	$ -	$ (10)	$ 16
Other postretirement	5	(3)	11	1	14
Total	$ 38	$ (10)	$ 11	$ (9)	$ 30

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		
	2009	2008	2007	2009	2008	2007
	%	%	%	%	%	%
Benefit obligations as of the measurement date:						
PacifiCorp-sponsored plans -						
Discount rate	5.80	6.90	6.30	5.85	6.90	6.45
Rate of compensation increase	3.00	3.50	4.00	N/A	N/A	N/A
MidAmerican Energy-sponsored plans -						
Discount rate	6.00	6.50	6.00	6.00	6.50	6.00
Rate of compensation increase	3.00	4.00	4.50	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
PacifiCorp-sponsored plans -						
Discount rate	6.90	6.30	5.76	6.90	6.45	6.00
Expected return on plan assets	7.75	7.75	8.00	7.75	7.75	8.00
Rate of compensation increase	3.50	4.00	4.00	N/A	N/A	N/A
MidAmerican Energy-sponsored plans -						
Discount rate	6.50	6.00	5.75	6.50	6.00	5.75
Expected return on plan assets	7.50	7.50	7.50	7.50	7.50	7.50
Rate of compensation increase	4.00	4.50	4.50	N/A	N/A	N/A

	2009	2008
Assumed healthcare cost trend rates as of the measurement date:		
PacifiCorp-sponsored plans -		
Healthcare cost trend rate assumed for next year – under 65	8.00%	8.00%
Healthcare cost trend rate assumed for next year – over 65	8.00%	6.00%
Rate that the cost trend rate gradually declines to	5.00%	5.00%
Year that the rate reaches the rate it is assumed to remain at – under 65	2016	2012
Year that the rate reaches the rate it is assumed to remain at – over 65	2016	2010
MidAmerican Energy-sponsored plans -		
Healthcare cost trend rate assumed for next year	8.00%	8.50%
Rate that the cost trend rate gradually declines to	5.00%	5.00%
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	39	(33)

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $117 million and $33 million, respectively, during 2010. Funding to the established pension trusts is based upon the actuarially determined costs of the plans 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. The Company 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. The Company'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 the Company's pension and other postretirement benefit plans for 2010 through 2014 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments			
		Other Postretirement		
	Pension	**Gross**	**Medicare Subsidy**	**Net of Subsidy**
2010	$ 140	$ 49	$ (5)	$ 44
2011	144	53	(6)	47
2012	150	55	(6)	49
2013	159	58	(7)	51
2014	168	62	(8)	54
2015-19	824	347	(45)	302

Plan Assets

Investment Policy and Asset Allocations

The Company'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 each plan's Pension and Employee Benefits Plans Administrative 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 the Company's pension and other postretirement benefit plan assets are as follows as of December 31, 2009:

	Pension[1]	Other Postretirement[1]
	%	%
PacifiCorp:		
Fixed-income securities[2]	33-37	33-37
Equity securities[2]	53-57	61-65
Limited partnership interests	8-12	1-3
Other	0-1	0-1
MidAmerican Energy:		
Fixed-income securities[2]	20-30	25-35
Equity securities[2]	65-75	60-80
Real estate funds	0-10	-
Other	0-5	0-5

(1) PacifiCorp’s pension plan trust includes a separate account that is used to fund benefits for the other postretirement plan. In addition to this separate account, the assets for other postretirement benefits are held in two Voluntary Employers’ Beneficiaries Association (“VEBA”) Trusts, each of which has its own investment allocation strategies. Target allocations for the other postretirement benefit plan include the separate account of the pension 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, as of December 31, 2009 (in millions):

	Input Levels for Fair Value Measurements[1]			
	Level 1	**Level 2**	**Level 3**	**Total**
Pension				
Cash equivalents	$ 15	$ 4	$ -	$ 19
Fixed-income securities:				
United States government obligations	26	-	-	26
International government obligations	-	65	-	65
Corporate obligations	-	94	-	94
Municipal obligations	-	4	-	4
Agency, asset and mortgage-backed obligations	-	88	-	88
Equity securities:				
United States companies	413	-	-	413
International companies	4	-	-	4
Investment funds[2]	95	415	-	510
Limited partnership interests[3]	-	-	80	80
Real estate funds	-	-	15	15
Total[4]	$ 553	$ 670	$ 95	$ 1,318
Other postretirement				
Cash equivalents	$ 7	$ -	$ -	$ 7
Fixed-income securities:				
United States government obligations	5	-	-	5
International government obligations	-	6	-	6
Corporate obligations	-	15	-	15
Municipal obligations	-	27	-	27
Agency, asset and mortgage-backed obligations	-	11	-	11
Equity securities:				
United States companies	190	-	-	190
International companies	2	-	-	2
Investment funds[2]	172	104	-	276
Limited partnership interests[3]	-	-	8	8
Total[4]	$ 376	$ 163	$ 8	$ 547

(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 of approximately 81% and 19%, respectively, for the pension plans and 61% and 39%, respectively, for the other postretirement plans.

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

(4) Net receivables of $4 million and $7 million related to the pension and other postretirement benefit plans, respectively, are excluded from the fair value measurement hierarchy.

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 real estate funds determine fair value of their underlying assets using independent appraisals given there is no current liquid market for the underlying assets.

The following table reconciles the beginning and ending balances of the Company's plan assets measured at fair value using significant Level 3 inputs for the year ended December 31, 2009 (in millions):

	Pension		Other Postretirement
	Limited Partnership Interests	**Real Estate Funds**	**Limited Partnership Interests**
Balance, January 1, 2009	$ 78	$ 27	$ 7
Actual return on plan assets still held at period end	5	(9)	1
Purchases, sales, issuances and settlements	(3)	(3)	-
Balance, December 31, 2009	$ 80	$ 15	$ 8

Defined Contribution Plans

The Company sponsors defined contribution pension plans (401(k) plans) covering substantially all employees. The Company's contributions vary depending on the plan, but are based primarily on each participant's level of contribution and cannot exceed the maximum allowable for tax purposes. Total Company contributions to these plans were $56 million, $41 million and $36 million for 2009, 2008 and 2007, respectively.

United Kingdom Operations

Certain wholly-owned subsidiaries of CE Electric UK participate in the Northern Electric group of the United Kingdom industry-wide Electricity Supply Pension Scheme (the "UK Plan"), which provides pension and other related defined benefits, based on final pensionable pay, to the majority of the employees of CE Electric UK.

Net Periodic Benefit Cost

For purposes of calculating the expected return on pension 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 UK Plan included the following components for the years ended December 31 (in millions):

	2009	**2008**	**2007**
Service cost	$ 13	$ 21	$ 24
Interest cost	84	98	95
Expected return on plan assets	(104)	(118)	(118)
Net amortization	13	21	31
Net periodic benefit cost	$ 6	$ 22	$ 32

Funded Status

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

	2009	2008
Plan assets at fair value, beginning of year	$ 1,172	$ 1,905
Employer contributions	69	89
Participant contributions	5	6
Actual return on plan assets	215	(312)
Benefits paid	(68)	(76)
Foreign currency exchange rate changes	130	(440)
Plan assets at fair value, end of year	$ 1,523	$ 1,172

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

	2009	2008
Benefit obligation, beginning of year	$ 1,251	$ 1,820
Service cost	13	21
Interest cost	84	98
Participant contributions	5	6
Actuarial gain	228	(162)
Benefits paid	(68)	(76)
Foreign currency exchange rate changes	138	(456)
Benefit obligation, end of year	$ 1,651	$ 1,251
Accumulated benefit obligation, end of year	$ 1,506	$ 1,202

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

	2009	2008
Plan assets at fair value, end of year	$ 1,523	$ 1,172
Less – Benefit obligation, end of year	1,651	1,251
Funded status	$ (128)	$ (79)
Amounts recognized on the Consolidated Balance Sheets-other long-term liabilities	$ (128)	$ (79)

Unrecognized Amounts

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

	2009	2008
Amounts not yet recognized as components of net periodic benefit cost:		
Net loss	$ 703	$ 547
Prior service cost	6	7
Total	$ 709	$ 554

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost, which are included in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets, for the years ended December 31 is as follows (in millions):

	2009	2008
Balance, beginning of year	$ 554	$ 453
Net loss arising during the year	117	269
Net amortization	(13)	(21)
Foreign currency exchange rate changes	51	(147)
Total	155	101
Balance, end of year	$ 709	$ 554

The net loss and prior service cost that will be amortized from accumulated other comprehensive income (loss) in 2010 into net periodic benefit cost are estimated to be $29 million and $1 million, respectively.

Plan Assumptions

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

	2009	2008	2007
	%	%	%
Benefit obligations as of December 31:			
Discount rate	5.70	6.40	5.90
Rate of compensation increase	2.75	3.25	3.45
Rate of future price inflation	3.20	3.00	3.20
Net periodic benefit cost for the years ended December 31:			
Discount rate	6.40	5.90	5.20
Expected return on plan assets	7.00	7.00	7.00
Rate of compensation increase	3.25	3.45	3.25
Rate of future price inflation	3.00	3.20	3.00

Contributions and Benefit Payments

Employer contributions to the UK Plan are expected to be £45 million during 2010. The expected benefit payments to participants in the UK Plan for 2010 through 2014 and for the five years thereafter, using the foreign currency exchange rate as of December 31, 2009, are summarized below (in millions):

2010	$ 71
2011	73
2012	75
2013	76
2014	79
2015-2019	425

Plan Assets

Investment Policy and Asset Allocations

CE Electric UK's investment policy for the UK Plan is to balance risk and return through a diversified portfolio of fixed-income securities, equity securities and real estate. Maturities for fixed-income securities are managed to targets consistent with prudent risk tolerances. The UK Plan retains outside investment advisors to manage plan investments within the parameters set by the trustees of the UK Plan in consultation with CE Electric UK. 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 is based on a weighted average of the expected historical performance for the types of assets in which the UK Plan invests.

The target allocations (percentage of plan assets) for the UK Plan assets are as follows as of December 31, 2009:

Fixed-income securities	57%
Equity securities	33
Real estate funds	10

Fair Value Measurements

The following table presents the fair value of the UK Plan assets, by major category, as of December 31, 2009 (in millions):

	Input Levels for Fair Value Measurements[1]			
	Level 1	Level 2	Level 3	Total
Cash equivalents	$ 13	$ -	$ -	$ 13
Fixed-income securities:				
United Kingdom government obligations	257	-	-	257
Other international government obligations	-	13	-	13
Corporate obligations	-	147	-	147
Investment funds[2]	79	881	-	960
Real estate funds	-	-	133	133
Total	$ 349	$ 1,041	$ 133	$ 1,523

(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 of approximately 58% and 42%, respectively.

The fair value of the UK Plan's assets are determined similar to the plan assets of the domestic plans as discussed previously in the note.

The following table reconciles the beginning and ending balances of the UK Plan assets measured at fair value using significant Level 3 inputs for the year ended December 31, 2009 (in millions):

	Real Estate Funds
Balance, January 1, 2009	$ 116
Actual return on plan assets still held at period end	6
Foreign currency exchange rate changes	11
Balance, December 31, 2009	$ 133

(15) Income Taxes

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

	2009	2008	2007
Current:			
Federal	$ (648)	$ 63	$ 147
State	(36)	74	38
Foreign	102	79	141
	(582)	216	326
Deferred:			
Federal	842	681	188
State	13	45	(6)
Foreign	15	46	(41)
	870	772	141
Investment tax credits, net	(6)	(6)	(11)
Total	$ 282	$ 982	$ 456

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:

	2009	2008	2007
Federal statutory income tax rate	35%	35%	35%
Income tax credits	(9)	(3)	(3)
State taxes, net of federal tax effect	2	3	2
Repairs deduction	(4)	-	-
Tax effect of foreign income	(2)	-	(2)
Effects of ratemaking	(2)	-	-
Change in UK corporate income tax rate	-	-	(4)
Effective income tax rate	20%	35%	28%

In 2009, the Utilities changed the method by which they determine current income tax deductions for repairs on certain of their regulated utility assets (the “repairs deduction”), which results in current deductibility for certain costs that are capitalized for book purposes. The repairs deduction was computed for tax years 1998 and forward and was deducted on the 2008 income tax returns. Iowa, MidAmerican Funding’s largest jurisdiction for rate regulated operations, requires immediate income recognition of such temporary differences. For the year-ended December 31, 2009, the Company’s earnings reflect $55 million of net tax benefits recognized from these deductions.

In 2007, the Company recognized $58 million of deferred income tax benefits upon the enactment of the reduction in the United Kingdom corporate income tax rate from 30% to 28% to be effective April 1, 2008.

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

	2009	2008
Deferred income tax assets:		
Regulatory liabilities	$ 638	$ 613
Employee benefits	400	408
Foreign carryforwards	390	333
Federal and state carryforwards	179	83
AROs	150	137
Revenue subject to refund	17	9
Nuclear reserve and decommissioning	7	25
Net unrealized losses	-	159
Other	346	319
Total deferred income tax assets	2,127	2,086
Valuation allowance	(9)	(10)
Total deferred income tax assets, net	2,118	2,076
Deferred income tax liabilities:		
Property, plant and equipment, net	(5,288)	(4,197)
Regulatory assets	(1,402)	(1,316)
Net unrealized gains	(568)	-
Unremitted foreign earnings	(385)	(346)
Other	(57)	(78)
Total deferred income tax liabilities	(7,700)	(5,937)
Net deferred income tax liability	$ (5,582)	$ (3,861)
Reflected as:		
Current assets	$ 81	$ 117
Current liabilities	(59)	(29)
Non-current liabilities	(5,604)	(3,949)
	$ (5,582)	$ (3,861)

As of December 31, 2009, the Company has available $371 million of foreign tax credit carryforwards that expire 10 years after the date the foreign earnings are repatriated through actual or deemed dividends and $19 million of foreign net operating loss carryforwards that expire in 2028. As of December 31, 2009, the statute of limitation had not begun on the foreign tax credit carryforwards. As of December 31, 2009, the Company has available $179 million of federal and state carryforwards, principally for net operating losses, that expire at various intervals between 2011 and 2028.

The United States Internal Revenue Service has closed examination of the Company’s income tax returns through 2003. In the United Kingdom, each legal entity is subject to examination by HM Revenue and Customs (“HMRC”), the United Kingdom equivalent of the United States Internal Revenue Service. HMRC has closed examination of income tax returns for all entities through 2007. In addition, state jurisdictions have closed examination of the Company’s income tax returns through at least 2003, except for PacifiCorp where the examinations have been closed through 1993 in most cases. The Company’s income tax returns in the Philippines, the most significant other foreign jurisdiction, have been closed through at least 2004.

As of December 31, 2009 and 2008, net unrecognized tax benefits totaled $273 million and $169 million, respectively, which included $139 million and $99 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 the Company’s effective tax rate.

(16) Commitments and Contingencies

Legal Matters

The Company is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. The Company does not believe that such normal and routine litigation will have a material effect on its consolidated financial results. The Company 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.

PacifiCorp

In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in the federal district court in Cheyenne, Wyoming, alleging violations of the Wyoming state opacity standards at PacifiCorp's Jim Bridger generating facility in Wyoming. Under Wyoming state requirements, which are part of the Jim Bridger generating facility's Title V permit and are enforceable by private citizens under the federal Clean Air Act, a potential source of pollutants such as a coal-fired generating facility must meet minimum standards for opacity, which is a measurement of light that is obscured in the flue of a generating facility. The complaint alleged thousands of violations of asserted six-minute compliance periods and sought an injunction ordering the Jim Bridger generating facility's compliance with opacity limits, civil penalties of $32,500 per day per violation and the plaintiffs' costs of litigation. In August 2009, the court ruled on a number of summary judgment motions by which it determined that the plaintiffs have sufficient legal standing to proceed with their complaint and that all other issues raised in the summary judgment motions will be resolved at trial. In February 2010, PacifiCorp, the Sierra Club and the Wyoming Outdoor Council reached an agreement in principle to settle all outstanding claims in the action. The settlement will be memorialized in a consent decree to be filed with the Environmental Protection Agency for review and also with the court for review and approval. If approved by the court as expected, the settlement is not expected to have a material impact on PacifiCorp's consolidated financial results.

CalEnergy Generation-Foreign

In February 2002, pursuant to the share ownership adjustment mechanism in the CE Casecnan Water and Energy Company, Inc. ("CE Casecnan") shareholder agreement, MEHC's indirect wholly owned subsidiary, CE Casecnan Ltd., advised the minority shareholder of CE Casecnan, LaPrairie Group Contractors (International) Ltd. ("LPG") that MEHC's indirect ownership interest in CE Casecnan had increased to 100% effective from commencement of commercial operations. In July 2002, LPG filed a complaint in the Superior Court of the State of California, City and County of San Francisco against CE Casecnan Ltd. and MEHC. LPG's complaint, as amended, seeks compensatory and punitive damages arising out of CE Casecnan Ltd.'s and MEHC's alleged improper calculation of the proforma financial projections and alleged improper settlement of the Philippine National Irrigation Administration arbitration. In January 2006, the Superior Court of the State of California entered a judgment in favor of LPG against CE Casecnan Ltd. Pursuant to the judgment, 15% of the distributions of CE Casecnan were deposited into escrow plus interest at 9% per annum. The judgment was appealed, and as a result of the appellate decision, CE Casecnan Ltd. determined that LPG would retain ownership of 10% of the shares of CE Casecnan, with the remaining 5% share to be transferred to CE Casecnan Ltd. subject to certain buy-up rights under the shareholder agreement. The issues relating to the exercise of the buy-up right have been decided by the court and in June 2009, LPG exercised its buy-up rights with respect to the remaining 5% ownership interest. In October 2009, the court issued a Final Judgment declaring that after the buy up LPG was a 15% shareholder. The Final Judgment was appealed on January 13, 2010 in the Superior Court of the State of California, City and County of San Francisco. On appeal, CE Casecnan Ltd. will argue that LPG is only entitled to a 10% interest in the project company, and will challenge the computation of the buy-up price for the still disputed 5% interest.

In July 2005, MEHC and CE Casecnan Ltd. commenced an action against San Lorenzo Ruiz Builders and Developers Group, Inc. ("San Lorenzo") in the District Court of Douglas County, Nebraska, seeking a declaratory judgment as to San Lorenzo's right to repurchase up to 15% of the shares in CE Casecnan. In January 2006, San Lorenzo filed a counterclaim against MEHC and CE Casecnan Ltd. seeking declaratory relief that it has effectively exercised its option to purchase up to 15% of the shares of CE Casecnan, that it is the rightful owner of such shares and that it is due all dividends paid on such shares. The parties have completed discovery and a trial has been set to begin in March 2010. The impact, if any, of this litigation on the Company cannot be determined at this time. The Company intends to vigorously defend the counterclaims.

Environmental Matters

The Company is subject to federal, state, local and foreign laws and regulations regarding air and water quality, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact the Company's current and future operations. The Company believes it is in material compliance with current environmental requirements.

Accrued Environmental Costs

The Company is fully or partly responsible for environmental remediation at various contaminated sites, including sites that are or were part of the Company's operations and sites owned by third parties. The Company accrues environmental remediation expenses when the expenses are believed to be probable and can be reasonably estimated. The quantification of environmental exposures is based on many factors, including changing laws and regulations, advancements in environmental technologies, the quality of available site-specific information, site investigation results, expected remediation or settlement timelines, the Company's proportionate responsibility, contractual indemnities and coverage provided by insurance policies. The liability recorded as of December 31, 2009 and 2008 was $21 million and $33 million, respectively, and is included in other current liabilities and other long-term liabilities on the Consolidated Balance Sheets. Environmental remediation liabilities that separately result from the normal operation of long-lived assets and that are legal obligations associated with the retirement of those assets are separately accounted for as asset retirement obligations.

Hydroelectric Relicensing

PacifiCorp's hydroelectric portfolio consists of 47 generating facilities with an aggregate facility net owned capacity of 1,158 megawatts ("MW"). The 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 generation facilities are operating under licenses that expire between 2030 and 2058. PacifiCorp is currently actively engaged in the relicensing process with the FERC for its Klamath hydroelectric system.

In February 2004, PacifiCorp filed with the FERC a final application for a new license to operate the 170-MW Klamath hydroelectric system in anticipation of the March 2006 expiration of the existing license. PacifiCorp is currently operating under an annual license issued by the FERC and expects to continue operating under annual licenses until the relicensing process is complete or the system's four mainstem dams are removed. As part of the relicensing process, the FERC is required to perform an environmental review, and in November 2007, the FERC issued its final environmental impact statement. The United States Fish and Wildlife Service and the National Marine Fisheries Service issued final biological opinions in December 2007 analyzing the Klamath hydroelectric system's impact on endangered species under a new FERC license consistent with the FERC staff's recommended license alternative and terms and conditions issued by the United States Departments of the Interior and Commerce. These terms and conditions include construction of upstream and downstream fish passage facilities at the Klamath hydroelectric system's four mainstem dams. Prior to the FERC issuing a final license, PacifiCorp is required to obtain water quality certifications from Oregon and California. PacifiCorp currently has water quality applications pending in Oregon and California.

In November 2008, PacifiCorp signed a non-binding agreement in principle ("AIP") that laid out a framework for the disposition of PacifiCorp's Klamath hydroelectric system relicensing process, including a path toward potential dam transfer and removal by an entity other than PacifiCorp no earlier than 2020. Subsequent to release of the AIP, negotiations between the parties continued with an expanded group of stakeholders. A final draft of the Klamath Hydroelectric Settlement Agreement ("KHSA") was released in January 2010 for public review. The parties to the KHSA, which include 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 KHSA in February 2010. Federal legislation to endorse and enact provisions of the KHSA is expected to be introduced in the United States Congress in 2010.

Under the terms of the KHSA, the United States Departments of the Interior and Commerce will conduct scientific and engineering studies and consult with state, local and tribal governments and other stakeholders, as appropriate, to determine by March 31, 2012 whether removal of the Klamath hydroelectric system's four mainstem dams will advance restoration of the salmonid fisheries of the Klamath Basin and is in the public interest. This determination will be made by the United States Secretary of the Interior. 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. 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. If dam removal costs exceed $200 million and the State of California is unable to raise the funds necessary for dam removal costs, sufficient funds would need to be obtained elsewhere in order for the KHSA and dam removal to proceed. Actual removal of a facility would occur only after all permits for removal are obtained and the facility and associated land are transferred to a dam removal entity. Prior to potential removal of a facility, the facility will generally continue to operate as it does currently. However, PacifiCorp is responsible for implementing interim measures to provide additional resource protections, water quality improvements, habitat enhancement for aquatic species and increased funding for hatchery operations in the Klamath River Basin.

In July 2009, Oregon's governor signed a bill authorizing PacifiCorp to collect surcharges from its Oregon customers for Oregon's share of the customer contribution for the cost of removing the Klamath hydroelectric system's four mainstem dams. PacifiCorp expects collection from Oregon customers to begin in March 2010. Also in March 2010, PacifiCorp expects to file with the California Public Utilities Commission to obtain approval to begin collecting a surcharge from its California customers.

As of December 31, 2009 and 2008, PacifiCorp had $67 million and $57 million, respectively, in costs related to the relicensing of the Klamath hydroelectric system included in construction in progress and reflected in property, plant and equipment, net on the Consolidated Balance Sheets.

Unconditional Purchase Obligations

The Company has the following unconditional purchase obligations as of December 31, 2009 (in millions) that are not reflected on the Consolidated Balance Sheet:

	Minimum payments required for						
	2010	**2011**	**2012**	**2013**	**2014**	**2015 and Thereafter**	**Total**
Contract type:							
Coal, electricity and natural gas contract commitments	$ 1,190	$ 894	$ 633	$ 454	$ 370	$ 2,685	$ 6,226
Purchase obligations	873	212	52	28	36	160	1,361
Operating leases, easements and maintenance contracts	96	78	58	45	31	306	614
Other	4	3	2	2	3	56	70
	$ 2,163	$ 1,187	$ 745	$ 529	$ 440	$ 3,207	$ 8,271

Coal, Electricity and Natural Gas Contract Commitments

The Utilities have fuel supply and related transportation and lime contracts for their coal-fired and gas generating facilities. The Utilities expect to supplement these contracts with additional contracts and spot market purchases to fulfill their future fossil fuel needs. The Utilities acquire a portion of their electricity through long-term purchases and exchange agreements. Included in the purchased electricity payments are any power purchase agreements that meet the definition of an operating lease.

Purchase Obligations

The Company has purchase obligations for an ongoing construction program to meet increased electricity usage, customer growth and system reliability objectives. Additionally, the Company has various other purchase obligations that are non-cancelable or cancelable only under certain conditions related to equipment maintenance and various other service and maintenance agreements. The amounts included in the table above relate to firm commitments. The following discussion describes the Company's overall commitments and includes amounts that the Company is not yet firmly committed through a purchase order or other agreement.

The Company has significant future capital requirements. Through its operating subsidiaries, the Company has approved plans for, or has committed to incur, significant future capital expenditures to develop incremental generating capacity, foster the use of renewable resources, enhance transmission capabilities and mitigate environmental impacts through the installation of emission reduction technology. 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 and nuclear; 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, 2009, 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, 2009, PacifiCorp had spent a total of $865 million, including non-cash equity AFUDC, on these emissions reduction projects. During 2010, PacifiCorp expects to file 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, 2009, PacifiCorp had spent a total of $796 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.

The 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, primarily in Wyoming, Utah, Idaho, Oregon and the desert Southwest. 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 resource areas, including renewable resources; and (e) improve the flow of electricity throughout PacifiCorp's six-state service area and the Western United States. Proposed transmission line segments are re-evaluated to ensure maximum benefits and timing before committing to move forward with permitting and construction. The first major transmission segments associated with this plan are expected to be placed in service during 2010, with other segments placed in service through 2019, depending on siting, permitting and construction schedules.

Operating Leases, Easements and Maintenance Contracts

The Company has non-cancelable operating leases primarily for computer equipment, office space, certain operating facilities, land and rail cars. These leases generally require the Company 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. The Company also has non-cancelable easements for land on which its wind-farm turbines are located, as well as non-cancelable maintenance contracts for the turbines. Rent expense on non-cancelable operating leases totaled $97 million for 2009, $115 million for 2008 and $122 million for 2007.

Guarantees

The Company has entered into guarantees as part of the normal course of business and the sale of certain assets. These guarantees are not expected to have a material impact on the Company's consolidated financial results. The Utilities are generally required to obtain state regulatory commission approval prior to guaranteeing debt or obligations of other parties.

(17) MEHC Shareholders' Equity

Common Stock

On March 14, 2000, and as amended on December 7, 2005, MEHC's shareholders entered into a Shareholder Agreement that provides specific rights to certain shareholders. One of these rights allows certain shareholders the ability to put their common shares back to MEHC at the then current fair value dependent on certain circumstances controlled by MEHC.

Common Stock Options

There were no common stock options granted, forfeited or that expired during each of the three years in the period ended December 31, 2009. There were 703,329 common stock options exercised during the year ended December 31, 2009 having an exercise price of $35.05 per share, or $25 million. Also in 2009, MEHC purchased the shares issued from the options exercised for $148 million. As a result, the Company recognized $125 million of stock-based compensation expense, including the Company's share of payroll taxes, for the year ended December 31, 2009, which is included in operating expense on the Consolidated Statements of Operations. As of December 31, 2009, there are no common stock options outstanding.

There were no common stock options exercised during the year ended December 31, 2008. There were 703,329 common stock options outstanding and exercisable with an exercise price of $35.05 per share and a remaining contractual life of 1.25 years as of December 31, 2008.

There were 370,000 common stock options exercised during the year ended December 31, 2007 having a weighted-average exercise price of $26.99 per share. There were 703,329 common stock options outstanding and exercisable with an exercise price of $35.05 per share and a remaining contractual life of 2.25 years as of December 31, 2007.

Restricted Net Assets

In connection with the 2006 acquisition of PacifiCorp by MEHC, MEHC and PacifiCorp have made commitments to the state commissions that limit the dividends PacifiCorp can pay to either MEHC or MEHC's wholly owned subsidiary, PPW Holdings LLC. As of December 31, 2009, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to MEHC or its affiliates without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 47.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. This minimum level of common equity declines annually to 46.25% for the year ending December 31, 2010, 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, 2009, PacifiCorp's actual common stock equity percentage, as calculated under this measure, exceeded the minimum threshold.

These commitments also restrict PacifiCorp from making any distributions to either MEHC or MEHC's wholly owned subsidiary, PPW Holdings LLC, 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, 2009, PacifiCorp's unsecured debt rating was A- by Standard & Poor's Rating Services, BBB+ by Fitch Ratings and Baa1 by Moody's Investor Service.

In conjunction with the March 1999 acquisition of MidAmerican Energy by MEHC, MidAmerican Energy committed to the IUB to use commercially reasonable efforts to maintain an investment grade rating on its long-term debt and to maintain its common equity level above 42% of total capitalization unless circumstances beyond its control result in the common equity level decreasing to below 39% of total capitalization. MidAmerican Energy must seek the approval from the IUB of a reasonable utility capital structure if MidAmerican Energy's common equity level decreases below 42% of total capitalization, unless the decrease is beyond the control of MidAmerican Energy. MidAmerican Energy is also required to seek the approval of the IUB if MidAmerican Energy's common equity level decreases to below 39%, even if the decrease is due to circumstances beyond the control of MidAmerican Energy. As of December 31, 2009, MidAmerican Energy's common equity ratio exceeded the minimum threshold computed on a basis consistent with its commitment.

As a result of these regulatory commitments, MEHC had restricted net assets of $7.776 billion as of December 31, 2009.

(18) Preferred Securities of Subsidiaries

The total outstanding preferred stock of PacifiCorp, which does not have mandatory redemption requirements, is $41 million as of December 31, 2009 and 2008, is included in noncontrolling interests on the Consolidated Balance Sheets and accrues annual dividends at varying rates between 4.52% to 7.0%. Generally, this 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.

The total outstanding cumulative preferred securities of MidAmerican Energy are not subject to mandatory redemption requirements and may be redeemed at the option of MidAmerican Energy at prices which, in the aggregate, total $31 million as of December 31, 2009 and 2008 and is included in noncontrolling interests on the Consolidated Balance Sheets. The securities accrue annual dividends at varying rates between 3.30% to 4.80%. The aggregate total the holders of all preferred securities outstanding as of December 31, 2009 and 2008 are entitled to upon involuntary bankruptcy was $30 million plus accrued dividends.

The total outstanding 8.061% cumulative preferred securities of a subsidiary of CE Electric UK, which are redeemable in the event of the revocation of the subsidiary's electricity distribution license by the Secretary of State, was $56 million as of December 31, 2009 and 2008 and is included in noncontrolling interests on the Consolidated Balance Sheets.

(19) Components of Accumulated Other Comprehensive (Loss) Income, Net

Accumulated other comprehensive income (loss) attributable to MEHC, net consists of the following components as of December 31 (in millions):

	2009	2008
Unrecognized amounts on retirement benefits, net of tax of $(201) and $(156)	$ (515)	$ (401)
Foreign currency translation adjustment	(191)	(446)
Fair value adjustment on cash flow hedges, net of tax of $- and $(3)	-	(7)
Unrealized gains (losses) on marketable securities, net of tax of $693 and $(16)	1,041	(25)
Total accumulated other comprehensive income (loss) attributable to MEHC, net	$ 335	$ (879)

Upon conversion of the Constellation Energy 8% Preferred Stock in 2008, the Company reclassified unrealized gains from AOCI to earnings totaling $271 million, net of tax of $187 million. The unrealized gain and reclassification of the gain is presented net on the Consolidated Statements of Changes in Equity.

(20) Other, Net

Other, net, as shown on the Consolidated Statements of Operations, for the years ending December 31 consists of the following (in millions):

	2009	2008	2007
Gain on Constellation Energy merger termination fee and investment	$ 37	$ 1,092	$ -
Allowance for equity funds used during construction	68	73	85
Corporate-owned life insurance income (expense)	24	(13)	12
Other	17	36	15
Total other, net	$ 146	$ 1,188	$ 112

Gain on Constellation Energy Merger Termination Fee and Investment

On December 17, 2008, MEHC and Constellation Energy terminated the Merger Agreement, which resulted in the receipt of a $175 million termination fee and the conversion of the Constellation Energy 8% Preferred Stock into $418 million of cash and 19.9 million shares of Constellation Energy common stock valued at $499 million as of December 31, 2008. During the year ended December 31, 2009, the Company sold 19.9 million shares of Constellation Energy common stock for $536 million, or an average price of $26.93 per share, and recognized gains totaling $37 million.

(21) Supplemental Cash Flows Information

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

	2009	2008	2007
Interest paid, net of amounts capitalized	$ 1,179	$ 1,218	$ 1,176
Income taxes (received) paid(1)	$ (288)	$ (140)	$ 287
Supplemental disclosure of non-cash investing transactions:			
Property, plant and equipment additions in accounts payable	$ 341	$ 570	$ 309
Conversion of Constellation Energy 8% Preferred Stock(2)	$ -	$ 1,458	$ -

(1) Includes $360 million and $266 million of income taxes received from Berkshire Hathaway in 2009 and 2008, respectively, and $133 million of income taxes paid to Berkshire Hathaway in 2007.

(2) In December 2008, MEHC converted its $1 billion investment in Constellation Energy 8% Preferred Stock into $1 billion of 14% Senior Notes due from Constellation Energy and 19.9 million shares of Constellation Energy common stock.

During 2008, the Company purchased $354 million of its MEHC senior and subsidiary debt. Of the total, $216 million was subsequently re-marketed during 2008 and the remainder matured.

(22) Segment Information

MEHC's reportable segments were determined based on how the Company's strategic units are managed. The Company's foreign reportable segments include CE Electric UK, whose business is principally in Great Britain, and CalEnergy Generation-Foreign, whose business is in the Philippines. Intersegment eliminations and adjustments, including the allocation of goodwill, have been made. Information related to the Company's reportable segments is shown below (in millions):

	Years Ended December 31,		
	2009	2008	2007
Operating revenue:			
PacifiCorp	$ 4,457	$ 4,498	$ 4,258
MidAmerican Funding	3,699	4,715	4,267
Northern Natural Gas	689	769	664
Kern River	372	443	404
CE Electric UK	825	993	1,079
CalEnergy Generation-Foreign	147	138	220
CalEnergy Generation-Domestic	31	30	32
HomeServices	1,037	1,133	1,500
Corporate/other[1]	(53)	(51)	(48)
Total operating revenue	$ 11,204	$ 12,668	$ 12,376
Depreciation and amortization:			
PacifiCorp	$ 558	$ 490	$ 496
MidAmerican Funding	336	282	269
Northern Natural Gas	63	60	58
Kern River	101	86	80
CE Electric UK	165	179	187
CalEnergy Generation-Foreign	23	22	50
CalEnergy Generation-Domestic	8	8	8
HomeServices	18	19	20
Corporate/other[1]	(16)	(17)	(18)
Total depreciation and amortization	$ 1,256	$ 1,129	$ 1,150
Operating income:			
PacifiCorp	$ 1,079	$ 952	$ 917
MidAmerican Funding	469	590	514
Northern Natural Gas	337	457	308
Kern River	221	305	277
CE Electric UK	394	514	555
CalEnergy Generation-Foreign	113	103	142
CalEnergy Generation-Domestic	15	15	12
HomeServices	11	(58)	33
Corporate/other[1]	(174)	(50)	(70)
Total operating income	2,465	2,828	2,688
Interest expense	(1,275)	(1,333)	(1,320)
Capitalized interest	41	54	54
Interest and dividend income	38	75	105
Other, net	146	1,188	112
Total income before income tax expense and equity income	$ 1,415	$ 2,812	$ 1,639

	Years Ended December 31,		
	2009	2008	2007
Interest expense:			
PacifiCorp	$ 412	$ 343	$ 314
MidAmerican Funding	197	207	179
Northern Natural Gas	60	61	58
Kern River	56	67	75
CE Electric UK	153	186	241
CalEnergy Generation-Foreign	4	8	13
CalEnergy Generation-Domestic	16	17	17
HomeServices	-	2	2
Corporate/other[1]	377	442	421
Total interest expense	$ 1,275	$ 1,333	$ 1,320
Income tax expense:			
PacifiCorp	$ 236	$ 239	$ 240
MidAmerican Funding	(43)	107	111
Northern Natural Gas	118	157	106
Kern River	63	90	78
CE Electric UK	66	82	47
CalEnergy Generation-Foreign	48	48	56
CalEnergy Generation-Domestic	1	1	-
HomeServices	17	(20)	15
Corporate/other[1]	(224)	278	(197)
Total income tax expense	$ 282	$ 982	$ 456
Capital expenditures:			
PacifiCorp	$ 2,328	$ 1,789	$ 1,518
MidAmerican Funding	439	1,473	1,300
Northern Natural Gas	177	196	225
Kern River	73	24	15
CE Electric UK	387	440	422
CalEnergy Generation-Foreign	1	1	1
HomeServices	6	12	26
Corporate/other	2	2	5
Total capital expenditures	$ 3,413	$ 3,937	$ 3,512

	As of December 31,		
	2009	2008	2007
Property, plant and equipment, net:			
PacifiCorp	$ 15,647	$ 13,824	$ 11,849
MidAmerican Funding	6,986	6,942	5,737
Northern Natural Gas	2,106	1,978	1,856
Kern River	1,717	1,722	1,772
CE Electric UK	4,132	3,612	4,606
CalEnergy Generation-Foreign	261	282	303
CalEnergy Generation-Domestic	206	213	223
HomeServices	59	66	76
Corporate/other	(178)	(185)	(201)
Total property, plant and equipment, net	$ 30,936	$ 28,454	$ 26,221

	As of December 31,		
	2009	2008	2007
Total assets:			
PacifiCorp	$ 20,244	$ 18,339	$ 16,049
MidAmerican Funding	10,732	10,632	9,377
Northern Natural Gas	2,657	2,595	2,488
Kern River	1,875	1,910	1,943
CE Electric UK	5,622	4,921	6,802
CalEnergy Generation-Foreign	463	442	479
CalEnergy Generation-Domestic	569	550	544
HomeServices	657	674	709
Corporate/other	1,865	1,378	825
Total assets	$ 44,684	$ 41,441	$ 39,216

(1) The remaining differences between the segment amounts and the consolidated amounts described as "Corporate/other" relate principally to intersegment eliminations for operating revenue and, for the other items presented, to (a) corporate functions, including administrative costs, interest expense, corporate cash and investments and related interest income and (b) intersegment eliminations.

The following table shows the change in the carrying amount of goodwill by reportable segment for the years ended December 31, 2009 and 2008 (in millions):

	PacifiCorp	MidAmerican Funding	Northern Natural Gas	Kern River	CE Electric UK	CalEnergy Generation-Domestic	Home-Services	Total
Balance, January 1, 2008	$ 1,125	$ 2,108	$ 275	$ 34	$ 1,335	$ 71	$ 391	$ 5,339
Acquisitions	-	-	-	-	-	-	1	1
Foreign currency translation	-	-	-	-	(276)	-	-	(276)
Other	1	(6)	(26)	-	(9)	-	(1)	(41)
Balance, December 31, 2008	1,126	2,102	249	34	1,050	71	391	5,023
Acquisitions	-	-	-	-	-	-	1	1
Foreign currency translation	-	-	-	-	80	-	-	80
Other	-	-	(26)	-	-	-	-	(26)
Balance, December 31, 2009	$ 1,126	$ 2,102	$ 223	$ 34	$ 1,130	$ 71	$ 392	$ 5,078

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

None.

Item 9A(T). Controls and Procedures

Disclosure Controls and Procedures

At the end of the period covered by this Annual Report on Form 10-K, the Company carried out an evaluation, under the supervision and with the participation of the Company'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 the Company'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, the Company's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), concluded that the Company's disclosure controls and procedures were effective to ensure that information required to be disclosed by the Company 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 the Company'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 the Company's internal control over financial reporting during the quarter ended December 31, 2009 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Management of the Company 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 the Company's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), the Company's management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting as of December 31, 2009 as required by the Securities Exchange Act of 1934 Rule 13a-15(c). In making this assessment, the Company'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," the Company's management concluded that the Company's internal control over financial reporting was effective as of December 31, 2009.

This report does not include an attestation report of the Company's registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the Company's registered public accounting firm pursuant to temporary rules of the SEC that permit the Company to provide only management's report in this Annual Report on Form 10-K.

MidAmerican Energy Holdings Company
March 1, 2010

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The Board of Directors appoints executive officers annually. There are no family relationships among the executive officers, nor, except as set forth in employment agreements, 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, 2010, with respect to the current directors and executive officers of MEHC:

DAVID L. SOKOL, 53, Chairman of the Board of Directors since 1994, Chief Executive Officer from 1993 to April 2008 and a director since 1991. Mr. Sokol also serves as Chairman of Johns Manville Corporation and Chairman and Chief Executive Officer of NetJets, Inc. and as a director of BYD Company Limited.

GREGORY E. ABEL, 47, President since 1998, Chief Executive Officer since 2008, director since 2000 and Chief Operating Officer from 1998 to 2008. Mr. Abel joined MEHC in 1992. Mr. Abel is also a director of PacifiCorp.

PATRICK J. GOODMAN, 43, Senior Vice President and Chief Financial Officer since 1999. Mr. Goodman joined MEHC in 1995. Mr. Goodman is also a director of PacifiCorp.

DOUGLAS L. ANDERSON, 51, Senior Vice President, General Counsel and Corporate Secretary since 2001. Mr. Anderson joined MEHC in 1993. Mr. Anderson is also a director of PacifiCorp.

MAUREEN E. SAMMON, 46, Senior Vice President and Chief Administrative Officer since 2007. Ms. Sammon has been employed by MidAmerican Energy and its predecessor companies since 1986 and has held several positions, including Vice President, Human Resources and Insurance.

WARREN E. BUFFETT, 79, Director. Mr. Buffett has been a director of MEHC since 2000 and has been Chairman of the Board of Directors and Chief Executive Officer of Berkshire Hathaway for more than five years. Mr. Buffett is also a director of The Washington Post Company and previously served as a director of The Coca-Cola Company.

WALTER SCOTT, JR., 78, Director. Mr. Scott has been a director of MEHC since 1991 and has been Chairman of the Board of Directors of Level 3 Communications, Inc., a successor to certain businesses of Peter Kiewit & Sons', Inc., for more than five years. Mr. Scott is also a director of Peter Kiewit & Sons', Inc., Berkshire Hathaway and Valmont Industries, Inc. and previously served as a director of Burlington Resources, Inc. and Commonwealth Telephone Enterprises, Inc.

MARC D. HAMBURG, 60, Director. Mr. Hamburg has been a director of MEHC since 2000 and has been Senior Vice President-Chief Financial Officer and Treasurer of Berkshire Hathaway for more than five years.

Board's Role in the Risk Oversight Process

MEHC's Board of Directors is responsible for the oversight of risk management and has not established a separate risk management and oversight committee.

Audit Committee and Audit Committee Financial Expert

The audit committee of the Board of Directors is comprised of Mr. Marc D. Hamburg. The Board of Directors has determined that Mr. Hamburg qualifies as an "audit committee financial expert," as defined by SEC rules, based on his education, experience and background. Based on the standards of the New York Stock Exchange Inc., on which the common stock of MEHC's majority owner, Berkshire Hathaway, is listed, MEHC's Board of Directors has determined that Mr. Hamburg is not independent because of his employment by Berkshire Hathaway.

Code of Ethics

MEHC 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 believe that the compensation paid to each of our President and 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 is comprised of Messrs. Warren E. Buffett and Walter Scott, Jr. The Compensation Committee is responsible for the establishment and oversight of our compensation policy. Approval of compensation decisions for our NEOs is made by the Compensation Committee, unless specifically delegated. Although the Compensation Committee reviews each NEO's complete compensation package at least annually, it has delegated to the Chairman of the Board of Directors, or Chairman, and the CEO authority to approve off-cycle pay changes, performance awards 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' initial compensation. Subsequently, the Compensation Committee reviews peer company data when making annual base salary and incentive recommendations for the Chairman and the CEO. The peer companies for 2009 were American Electric Power Company, Inc., Consolidated Edison, Inc., Dominion Resources, Inc., Edison International, Energy Future Holdings Corp., Entergy Corporation, Exelon Corporation, FirstEnergy Corp., FPL Group, Inc., PG&E Corporation, Progress Energy, Inc., Public Service Enterprise Group Incorporated, Sempra Energy, The Southern Company and Xcel Energy Inc.

We engage the compensation practice of Towers Watson to research and document the peer company data to be reviewed by the Compensation Committee when making annual base salary and incentive recommendations for the Chairman and the CEO. The fee paid to Towers Watson for this service was $6,420 in 2009. We also engage Towers Watson to provide other services unrelated to executive compensation, including actuarial and consulting services related to our retirement plans. These services are approved by senior management and the aggregate fees paid to Towers Watson for these services were $466,000 in 2009. Our Board of Directors is not involved in the selection or approval of Towers Watson for these services.

Discussion and Analysis of Specific Compensation Elements

Base Salary

We determine base salaries for all our NEOs 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 is determined on a subjective basis after consideration of these factors and is not based on target percentiles or other formal criteria. The Chairman and CEO together make recommendations regarding the other NEOs' base salaries. The Chairman makes recommendations regarding the CEO's base salary, and the Compensation Committee sets our Chairman's base salary. All merit increases are approved by the Compensation Committee and take effect on January 1 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 2009, base salaries for all NEOs increased on average by 1.7% effective January 1, 2009. There have been no base salary changes for our NEOs since the January 1, 2009 merit increase.

Short-Term Incentive Compensation

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

Performance Incentive Plan

Under our Performance Incentive Plan, or PIP, all NEOs are eligible to earn an annual discretionary cash incentive award, which is determined on a subjective basis and is not based on a specific formula or cap. Awards paid to a NEO under the PIP are based on a variety of measures linked to each NEO's performance, our overall performance and each NEO's contribution to that overall performance. An individual NEO's performance is measured against defined objectives that commonly include financial and non-financial measures (e.g., 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. The Chairman and the CEO together recommend annual incentive awards for the other NEOs to the Compensation Committee prior to the last committee meeting of each year, held in the fourth quarter. The Chairman recommends the annual incentive award for the CEO, and the Compensation Committee determines the Chairman's award. If approved by the Compensation Committee, awards are paid prior to year-end.

Performance Awards

In addition to the annual awards under the PIP, we may grant cash performance awards periodically during the year to one or more NEOs to reward the accomplishment of significant non-recurring tasks or projects. These awards are discretionary and are approved by the CEO, as delegated by the Chairman and the Compensation Committee. There were no performance awards granted to our NEOs during 2009. Although both Messrs. Sokol and Abel are eligible for performance awards, neither has been granted an award in the past five years.

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 have not issued stock options or other forms of equity-based awards since March 2000. All stock options previously held by Messrs. Sokol and Abel have been exercised and are no longer outstanding.

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. Messrs. Goodman and Anderson and Ms. Sammon, as well as 95 other employees, participate in this plan, while our Chairman and our CEO do not. Our 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 the Chairman and the CEO who recommend awards to the 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. In 2009, participants allocated the value of their deferral accounts among various investment alternatives, which were determined by a vote of all participants. Beginning in 2010, the investment allocation for each participant's deferral accounts has been determined by each participant rather than by the vote of all participants. 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.

Incremental Profit Sharing Plan

The Incremental Profit Sharing Plan, or IPSP, is designed to align our interests and the interests of the Chairman and the CEO. The IPSP provides for a cash award to each participant based upon our achievement of a specified adjusted diluted earnings per share, or EPS, target for any calendar year. The EPS targets to achieve the award were established by the Compensation Committee in 2009 and are to be achieved no later than calendar year end 2013. The individual profit sharing award that may be earned is $12 million if our EPS is greater than $23.14 per share, but less than or equal to $24.24 per share, $25 million if our EPS is greater than $24.24 per share, but less than $25.37 per share, or $40 million if our EPS is greater than $25.37 per share. Messrs. Goodman and Anderson and Ms. Sammon do not participate in this plan.

Other Employee Benefits

Supplemental Executive Retirement Plan

The MidAmerican Energy Company Supplemental Executive Retirement Plan for Designated Officers, or SERP, provides additional retirement benefits to participants. We include the SERP as part of the participating NEO's overall compensation in order to provide a comprehensive, competitive package and as a key retention tool. Messrs. Sokol, Abel and Goodman participate in the SERP and we have no plans to add new participants in the future. The SERP provides annual retirement benefits of up to 65% of a participant's total cash compensation in effect immediately prior to retirement, subject to an annual $1 million maximum retirement benefit. Total cash compensation means (a) the highest amount payable to a participant as monthly base salary during the five years immediately prior to retirement multiplied by 12, plus (b) the average of the participant's annual awards under an annual incentive bonus program during the three years immediately prior to the year of retirement and (c) special, additional or non-recurring bonus awards, if any, that are required to be included in total cash compensation pursuant to a participant's employment agreement or approved for inclusion by the Board of Directors. All participating NEOs have met the five-year service requirement under the plan. Mr. Goodman's SERP benefit will be reduced by the amount of his regular retirement benefit under the MidAmerican Energy Company Retirement Plan, his actuarially equivalent benefit under the fixed 401(k) contribution option and ratably for retirement between ages 55 and 65.

Deferred Compensation Plan

The MidAmerican Energy Holdings Company Executive Voluntary Deferred Compensation Plan, or DCP, provides a means for all NEOs 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, however we have not made contributions to date.

Financial Planning and Tax Preparation

We reimburse NEOs for financial planning and tax preparation services. The value of the benefit is included in the NEO's taxable income. It is offered both as a competitive benefit itself and also to help ensure our NEOs best utilize the other forms of compensation we provide to them.

Executive Life Insurance

We provide universal life insurance to Messrs. Sokol, Abel and Goodman, having a death benefit of two times annual base salary during employment, reducing to one times annual base salary in retirement. The value of the benefit is included in the NEO's taxable income. We include the executive life insurance as part of the participating NEO's overall compensation in order to provide a comprehensive, competitive package.

Potential Payments Upon Termination

Certain NEOs are entitled to post-termination payments in the event their employment is terminated under certain circumstances. We believe these post-termination payments are an important component of the competitive compensation package we offer to these NEOs.

Compensation Committee Report

The Compensation Committee, consisting of Messrs. Buffett and Scott, 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 ($)	Bonus[1] ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings[2] ($)	All Other Compensation[3] ($)	Total[4] ($)
David L. Sokol, Chairman of the Board of Directors	2009	$ 750,000	$ 6,000,000	$ -	$ 980,000	$ 252,926	$ 7,982,926
	2008	822,917	13,000,000	-	-	424,749	14,247,666
	2007	850,000	4,000,000	-	-	213,038	5,063,038
Gregory E. Abel, President and Chief Executive Officer	2009	1,000,000	5,000,000	-	890,000	266,699	7,156,699
	2008	1,000,000	5,000,000	-	369,000	437,792	6,806,792
	2007	775,000	4,000,000	-	-	370,624	5,145,624
Patrick J. Goodman, Senior Vice President and Chief Financial Officer	2009	340,000	1,292,543	-	203,000	58,667	1,894,210
	2008	330,000	673,081	-	18,000	45,631	1,066,712
	2007	320,000	889,306	-	51,000	47,868	1,308,174
Douglas L. Anderson, Senior Vice President and General Counsel	2009	308,000	922,618	-	5,000	51,650	1,287,268
	2008	300,000	558,397	-	28,000	31,536	917,933
	2007	291,500	788,705	-	20,000	29,372	1,129,577
Maureen E. Sammon, Senior Vice President and Chief Administrative Officer	2009	221,000	524,790	-	5,000	37,495	788,285
	2008	215,000	250,930	-	31,000	20,159	517,089
	2007	196,659	452,903	-	17,000	20,291	686,853

(1) Consists of annual cash incentive awards earned pursuant to the PIP for our NEOs, performance awards earned related to non-routine projects, special achievement bonuses and the vesting of LTIP awards and associated vested earnings. The breakout for 2009 is as follows:

	PIP	Performance Award	Special Achievement Bonus	LTIP	
David L. Sokol	$ 6,000,000	$ -	$ -	$ -	
Gregory E. Abel	5,000,000	-	-	-	
Patrick J. Goodman	375,000	-	-	917,543	($288,543 in investment earnings)
Douglas L. Anderson	300,000	-	-	622,618	($209,387 in investment earnings)
Maureen E. Sammon	140,000	-	-	384,790	($129,490 in investment earnings)

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 are subject to discretionary adjustment by the Chairman, CEO and Compensation Committee. In 2009, the gross award and per-point value were determined based on the overall achievement of our financial and non-financial objectives.

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 the Chairman and the CEO, based upon a discretionary evaluation of individual achievement of financial and non-financial goals previously described herein. A participant's award equals the participants allocated points multiplied by the final per-point value, capped at 1.5 times base salary except in extraordinary circumstances.

(2) Amounts are based upon the aggregate increase in the actuarial present value of all qualified and nonqualified defined benefit plans, which include our cash balance and SERP, 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.

(3) Amounts consist of vacation payouts and defined contribution plan matching and fixed contributions we paid on behalf of the NEOs, as well as perquisites and other personal benefits related to life insurance premiums, the personal use of corporate aircraft and financial planning and tax preparation that we paid on behalf of Messrs. Sokol, Abel, Goodman and Anderson. The personal use of corporate aircraft represents our incremental cost of providing this personal benefit determined by applying the percentage of flight hours used for personal use to our variable expenses incurred from operating our corporate aircraft. All other compensation is based upon amounts paid by us.

Items required to be reported and quantified are as follows: Mr. Sokol - life insurance premiums of $50,395 and personal use of corporate aircraft of $180,366; Mr. Abel - life insurance premiums of $64,103 and personal use of corporate aircraft of $182,865; Mr. Goodman - life insurance premiums of $16,050, financial planning and tax preparation of $5,085 and 401(k) fixed contributions of $19,150; Mr. Anderson - vacation payouts of $22,507 and 401(k) fixed contributions of $19,150; and Ms. Sammon - 401(k) fixed contributions of $18,590.

(4) Any amounts voluntarily deferred by the NEO, if applicable, are included in the appropriate column in the summary compensation table.

Option Exercises and Stock Vested

The following table sets forth information regarding stock options exercised by Messrs. Sokol and Abel during the year ended December 31, 2009:

Name	Option Awards[1] Number of shares acquired on exercises (#)	Value realized on exercise ($)
David L. Sokol	549,277	$ 96,096,011
Gregory E. Abel	154,052	26,951,397

(1) We have not issued stock options or other forms of equity-based awards since March 2000. All stock option exercises relate to previously granted options held by Messrs. Sokol and Abel and were fully vested prior to 2009. Accordingly, we have omitted the Stock Awards columns from the Option Exercises and Stock Vested Table. Neither Mr. Sokol nor Mr. Abel has any outstanding stock options as of December 31, 2009.

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, 2009:

Name	Plan name	Number of years credited service[1] (#)	Present value of accumulated benefit[2] ($)	Payments during last fiscal year ($)
David L. Sokol	SERP	n/a	$ 6,395,000	$ -
	MidAmerican Energy Company Retirement Plan	n/a	236,000	-
Gregory E. Abel	SERP	n/a	4,935,000	-
	MidAmerican Energy Company Retirement Plan	n/a	227,000	-
Patrick J. Goodman	SERP	15 years	618,000	-
	MidAmerican Energy Company Retirement Plan	11 years	204,000	-
Douglas L. Anderson	MidAmerican Energy Company Retirement Plan	11 years	209,000	-
Maureen E. Sammon	MidAmerican Energy Company Retirement Plan	23 years	235,000	-

(1) The pension benefits for Messrs. Sokol and Abel do not depend on their years of service, as both have already reached their maximum benefit levels based on their respective ages and previous triggering events described in their employment agreements. Mr. Goodman’s credited years of service includes eleven years of service with us and, for purposes of the SERP only, four additional years of imputed service from a predecessor company.

(2) 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, 2009, which is the measurement date for the plans. The present value of accumulated benefits for the SERP was calculated using the following assumptions: (1) Mr. Sokol – a 100% joint and survivor annuity; (2) Mr. Abel – a 100% joint and survivor annuity; and (3) Mr. Goodman – a 66 2/3% joint and survivor annuity. The present value of accumulated benefits for the MidAmerican Energy Company Retirement Plan was calculated using a lump sum payment assumption. The present value assumptions used in calculating the present value of accumulated benefits for both the SERP and the MidAmerican Energy Company Retirement Plan were as follows: a cash balance interest crediting rate of 1.77% in 2009, 1.01% in 2010 and 5.25% thereafter; cash balance conversion rates of 5.10% in 2009, 5.40% in 2010, 5.70% in 2011 and 6.00% in 2012 and thereafter; a discount rate of 6.00%; an expected retirement age of 65; postretirement mortality using the RP-2000 M/F tables; and cash balance conversion mortality using the Notice 2008-85 tables.

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

The SERP provides annual retirement benefits up to 65% of a participant’s total cash compensation in effect immediately prior to retirement, subject to an annual $1 million maximum retirement benefit. Total cash compensation means (i) the highest amount payable to a participant as monthly base salary during the five years immediately prior to retirement multiplied by 12, plus (ii) the average of the participant’s awards under an annual incentive bonus program during the three years immediately prior to the year of retirement and (iii) special, additional or non-recurring bonus awards, if any, that are required to be included in total cash compensation pursuant to a participant’s employment agreement or approved for inclusion by the Board of Directors. Mr. Goodman’s SERP benefit will be reduced by the amount of his regular retirement benefit under the MidAmerican Energy Company Retirement Plan, his actuarially equivalent benefit under the fixed 401(k) contribution option and ratably for retirement between ages 55 and 65. A survivor benefit is payable to a surviving spouse under the SERP. Benefits from the SERP will be paid out of general corporate funds; however, through a Rabbi trust, we maintain life insurance on participants in amounts expected to be sufficient to fund the after-tax cost of the projected benefits. Deferred compensation is considered part of the salary covered by the SERP.

Under the MidAmerican Energy Company Retirement Plan, each NEO has an account, for record-keeping purposes only, to which credits are allocated annually based upon a percentage of the NEO’s base salary and incentive paid in the plan year. In addition, all balances in the accounts of NEOs earn a fixed rate of interest that is credited annually. The interest rate for a particular year is based on the one-year constant maturity Treasury yield plus seven-tenths of one percentage point. Each NEO is vested in the MidAmerican Energy Company Retirement Plan. At retirement, or other termination of employment, an amount equal to the vested balance then credited to the account is payable to the NEO in the form of a lump sum or an annuity.

Nonqualified Deferred Compensation

The following table sets forth certain information regarding the nonqualified deferred compensation plan accounts held by each of our NEOs at December 31, 2009:

Name	Executive contributions in 2009[(1)] ($)	Registrant contributions in 2009 ($)	Aggregate earnings in 2009 ($)	Aggregate withdrawals/ distributions ($)	Aggregate balance as of December 31, 2009[(2)] ($)
David L. Sokol	$ -	$ -	$ -	$ -	$ -
Gregory E. Abel	250,000	-	165,309	-	1,157,050
Patrick J. Goodman	-	-	169,644	(40,019)	966,189
Douglas L. Anderson	-	-	163,807	(35,824)	1,268,906
Maureen E. Sammon	160,140	-	122,297	-	735,943

(1) The contribution amount shown for Mr. Abel is included in the 2009 total compensation reported for him in the Summary Compensation Table and is not additional earned compensation. The contribution amount shown for Ms. Sammon includes $83,847 earned toward her 2005 LTIP award prior to 2009 and thus is not included in the 2009 total compensation reported for her in the Summary Compensation Table.

(2) Excludes the value of 10,041 shares of our common stock reserved for issuance to Mr. Abel. Mr. Abel deferred the right to receive the value of these shares pursuant to a legacy nonqualified deferred compensation plan.

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. 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

We have entered into employment agreements with Messrs. Sokol, Abel and Goodman that provide for payments following termination of employment under various circumstances, which do not include change-in-control provisions.

Mr. Sokol's employment will terminate upon his resignation, permanent disability, death, termination by us with or without cause, or our failure to provide Mr. Sokol with the compensation or to maintain the job responsibilities set forth in his employment agreement. A termination of employment of either Messrs. Abel or Goodman will occur upon his resignation (with or without good reason), permanent disability, death, or termination by us with or without cause. The employment agreements for Messrs. Sokol and Abel also include provisions specific to the calculation of their respective SERP benefits.

Neither Mr. Anderson nor Ms. Sammon has an employment agreement. Where a NEO does not have an employment agreement, or in the event that the agreements for Messrs. Sokol, Abel and Goodman do not address an issue, payments upon termination are determined by the applicable plan documents and our general employment policies and practices as discussed below.

The following discussion provides further detail on post-termination payments.

David L. Sokol

Mr. Sokol's employment agreement provides that in the event Mr. Sokol is terminated as Chairman of the Board due to death, disability or other than for cause, he is entitled to (i) any accrued but unpaid base salary plus an amount equal to the aggregate annual base salary that would have been paid to him through the fifth anniversary of the date he commenced his employment solely as Chairman of the Board and (ii) the continuation of his senior executive employee benefits (or the economic equivalent thereof) through such fifth anniversary.

Payments made in accordance with the employment agreement are contingent on Mr. Sokol complying with the confidentiality and post-employment restrictions described therein. The term of the agreement is the period of time beginning on the date Mr. Sokol relinquished his position as CEO, April 16, 2008, and ending on the fifth anniversary of such date, April 16, 2013, unless earlier terminated pursuant to the agreement.

The following table sets forth the estimated enhancements to payments pursuant to the termination scenarios described above. Payments or benefits that are not enhanced in form or amount upon the occurrence of a particular termination scenario, which include 401(k) account balances and those portions of life insurance benefits 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, 2009, and are payable as lump sums unless otherwise noted.

Termination Scenario	Cash Severance[1]	Incentive	Life Insurance[2]	Pension[3]	Benefits Continuation[4]	Excise and Other Taxes[5]
Retirement	$ -	$ -	$ -	$ 8,435,000	$ -	$ -
Involuntary Without Cause, Company Breach and Disability	2,468,750	-	-	8,435,000	80,170	-
Death	2,468,750	-	1,432,804	7,697,000	80,170	-

(1) The cash severance payments are determined in accordance with Mr. Sokol's employment agreement.

(2) Life insurance benefits are equal to two times base salary, as of the preceding June 1, less the benefits otherwise payable in all other termination scenarios, which are equal to the total cash value of the policies less cumulative premiums paid by us.

(3) 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. Mr. Sokol's death scenario is based on a 100% joint and survivor with 15-year certain annuity commencing immediately. Mr. Sokol's other termination scenarios are based on a 100% joint and survivor annuity commencing immediately.

(4) Includes health and welfare, life insurance and financial planning and tax preparation benefits for five years. The health and welfare benefit amounts are estimated using the rates we currently charge employees terminating employment but electing to continue their medical, dental and vision insurance after termination. These amounts are grossed-up for taxes and then reduced by the amount Mr. Sokol would have paid if he had continued his employment. The life insurance benefit amounts are based on the cost of individual policies offering benefits equivalent to our group coverage and are grossed-up for taxes. These amounts also assume benefit continuation for the entire five year period, with no offset by another employer. We will also continue to provide financial planning and tax preparation reimbursement, or the economic equivalent thereof, for five years or pay a lump sum cash amount to keep Mr. Sokol in the same economic position on an after-tax basis. The amount included is based on an annual estimated cost using the most recent three-year average annual reimbursement. If it is determined that benefits paid with respect to the extension of medical and dental benefits to Mr. Sokol would not be exempt from taxation under the Internal Revenue Code, we shall pay to Mr. Sokol a lump sum cash payment following separation from service to allow him to obtain equivalent medical and dental benefits and which would put him in the same after-tax economic position.

(5) As provided in Mr. Sokol's employment agreement, should it be deemed under Section 280G of the Internal Revenue Code that termination payments constitute excess parachute payments subject to an excise tax, we will gross up such payments to cover the excise tax and any additional taxes associated with such gross-up. Based on computations prescribed under Section 280G and related regulations, we do not believe that any of the termination scenarios are subject to any excise tax.

Gregory E. Abel

Mr. Abel's employment agreement entitles him to receive two years base salary continuation and payments in respect of average bonuses for the prior two years in the event we terminate his employment other than for cause. The payments are to be paid as a lump sum with no discount for present valuation.

In addition, if Mr. Abel's employment is terminated due to death, permanent disability or other than for cause, he is entitled to continuation of his senior executive employee benefits (or the economic equivalent thereof) for two years. If Mr. Abel resigns, we must pay him any accrued but unpaid base salary, unless he resigns for good reason, in which case he will receive the same benefits as if he were terminated other than for cause.

Payments made in accordance with the employment agreement are contingent on Mr. Abel complying with the confidentiality and post-employment restrictions described therein. The term of the agreement effectively expires on August 6, 2014, and is extended automatically for additional one year terms thereafter subject to Mr. Abel's election to decline renewal at least 365 days prior to the August 6 that is four years prior to the current expiration date (or by August 6, 2010 for the agreement not to extend to August 6, 2015).

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 life insurance benefits 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, 2009, and are payable as lump sums unless otherwise noted.

Termination Scenario	Cash Severance(1)	Incentive	Life Insurance(2)	Pension(3)	Benefits Continuation(4)	Excise and Other Taxes(5)
Retirement, Voluntary and Involuntary With Cause	$ -	$ -	$ -	$ 10,947,000	$ -	$ -
Involuntary Without Cause, Disability and Voluntary With Good Reason	12,000,000	-	-	10,947,000	53,167	-
Death	12,000,000	-	1,957,437	10,608,000	53,167	-

(1) The cash severance payments are determined in accordance with Mr. Abel's employment agreement.

(2) Life insurance benefits are equal to two times base salary, as of the preceding June 1, less the benefits otherwise payable in all other termination scenarios, which are equal to the total cash value of the policies less cumulative premiums paid by us.

(3) 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. Mr. Abel's death scenario is based on a 100% joint and survivor with 15-year certain annuity commencing immediately. Mr. Abel's other termination scenarios are based on a 100% joint and survivor annuity commencing immediately.

(4) Includes health and welfare, life insurance and financial planning and tax preparation benefits for two years. The health and welfare benefit amounts are estimated using the rates we currently charge employees terminating employment but electing to continue their medical, dental and vision insurance after termination. These amounts are grossed-up for taxes and then reduced by the amount Mr. Abel would have paid if he had continued his employment. The life insurance benefit amounts are based on the cost of individual policies offering benefits equivalent to our group coverage and are grossed-up for taxes. These amounts also assume benefit continuation for the entire two year period, with no offset by another employer. We will also continue to provide financial planning and tax preparation reimbursement, or the economic equivalent thereof, for two years or pay a lump sum cash amount to keep Mr. Abel in the same economic position on an after-tax basis. The amount included is based on an annual estimated cost using the most recent three-year average annual reimbursement. If it is determined that benefits paid with respect to the extension of medical and dental benefits to Mr. Abel would not be exempt from taxation under the Internal Revenue Code, we shall pay to Mr. Abel a lump sum cash payment following separation from service to allow him to obtain equivalent medical and dental benefits and which would put him in the same after-tax economic position.

(5) As provided in Mr. Abel's employment agreement, should it be deemed under Section 280G of the Internal Revenue Code that termination payments constitute excess parachute payments subject to an excise tax, we will gross up such payments to cover the excise tax and any additional taxes associated with such gross-up. Based on computations prescribed under Section 280G and related regulations, we believe that none of the termination scenarios are subject to any excise tax.

Patrick J. Goodman

Mr. Goodman's employment agreement entitles him to receive two years base salary continuation and payments in respect of average bonuses for the prior two years in the event we terminate his employment other than for cause. The payments are to be paid as a lump sum with no discount for present valuation.

In addition, if Mr. Goodman's employment is terminated due to death, permanent disability or other than for cause, he is entitled to continuation of his senior executive employee benefits (or the economic equivalent thereof) for one year. If Mr. Goodman resigns, we must pay him any accrued but unpaid base salary, unless he resigns for good reason, in which case he will receive the same benefits as if he were terminated other than for cause.

Payments made in accordance with the employment agreement are contingent on Mr. Goodman complying with the confidentiality and post-employment restrictions described therein. The term of the agreement expires on April 21, 2011, but is extended automatically for additional one year terms thereafter subject to Mr. Goodman's election to decline renewal at least 365 days prior to the then current expiration date or termination.

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, life insurance benefits 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, 2009, and are payable as lump sums unless otherwise noted.

Termination Scenario	Cash Severance[(1)]	Incentive[(2)]	Life Insurance[(3)]	Pension[(4)]	Benefits Continuation[(5)]	Excise and Other Taxes[(6)]
Retirement and Voluntary	$ -	$ -	$ -	$ 631,000	$ -	$ -
Involuntary With Cause	-	-	-	-	-	-
Involuntary Without Cause and Voluntary With Good Reason	2,887,500	-	-	631,000	16,408	993,671
Death	2,887,500	1,432,588	667,776	3,844,000	16,408	-
Disability	2,887,500	1,432,588	-	1,823,000	16,408	-

(1) The cash severance payments are determined in accordance with Mr. Goodman's employment agreement.

(2) Amounts represent the unvested portion of Mr. Goodman's LTIP account, which becomes 100% vested upon his death or disability.

(3) Life insurance benefits are equal to two times base salary, as of the preceding June 1, less the benefits otherwise payable in all other termination scenarios, which are equal to the total cash value of the policies less cumulative premiums paid by us.

(4) 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. Mr. Goodman's voluntary termination, retirement, involuntary without cause, and change in control termination scenarios are based on a 66 2/3% joint and survivor annuity commencing at age 55 (reductions for termination prior to age 55 and commencement prior to age 65). Mr. Goodman's disability scenario is based on a 66 2/3% joint and survivor annuity commencing at age 55 (no reduction for termination prior to age 55, reduced for commencement prior to age 65). Mr. Goodman's death scenario is based on a 100% joint and survivor with 15-year certain annuity commencing immediately (no reduction for termination prior to age 55 and commencement prior to age 65).

(5) Includes health and welfare, life insurance and financial planning and tax preparation benefits for one year. The health and welfare benefit amounts are estimated using the rates we currently charge employees terminating employment but electing to continue their medical, dental and vision insurance after termination. These amounts are grossed-up for taxes and then reduced by the amount Mr. Goodman would have paid if he had continued his employment. The life insurance benefit amounts are based on the cost of individual policies offering benefits equivalent to our group coverage and are grossed-up for taxes. These amounts also assume benefit continuation for the entire one year period, with no offset by another employer. We will also continue to provide financial planning and tax preparation reimbursement, or the economic equivalent thereof, for one year or pay a lump sum cash amount to keep Mr. Goodman in the same economic position on an after-tax basis. The amount included is based on an annual estimated cost using the most recent three-year average annual reimbursement.

(6) As provided in Mr. Goodman's employment agreement, should it be deemed under Section 280G of the Internal Revenue Code that termination payments constitute excess parachute payments subject to an excise tax, we will gross up such payments to cover the excise tax and any additional taxes associated with such gross-up. Based on computations prescribed under Section 280G and related regulations, we believe that only the Involuntary Without Cause and Voluntary With Good Reason termination scenarios are subject to any excise tax.

Douglas L. Anderson

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, 2009, and are payable as lump sums unless otherwise noted.

Termination Scenario	Cash Severance	Incentive[1]	Life Insurance	Pension[2]	Benefits Continuation	Excise and Other Taxes
Retirement, Voluntary and Involuntary With or Without Cause	$ -	$ -	$ -	$ 30,000	$ -	$ -
Death and Disability	-	845,689	-	30,000	-	-

(1) Amounts represent the unvested portion of Mr. Anderson's LTIP account, which becomes 100% vested upon his death or disability.

(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.

Maureen E. Sammon

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, 2009, and are payable as lump sums unless otherwise noted.

Termination Scenario	Cash Severance	Incentive[1]	Life Insurance	Pension[2]	Benefits Continuation	Excise and Other Taxes
Retirement, Voluntary and Involuntary With or Without Cause	$ -	$ -	$ -	$ 45,000	$ -	$ -
Death and Disability	-	509,513	-	45,000	-	-

(1) Amounts represent the unvested portion of Ms. Sammon's LTIP account, which becomes 100% vested upon her death or disability.

(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.

Director Compensation

Our directors are not paid any fees for serving as directors. All directors are reimbursed for their expenses incurred in attending Board of Directors meetings.

Compensation Committee Interlocks and Insider Participation

Mr. Buffett is the Chairman of the Board of Directors and Chief Executive Officer of Berkshire Hathaway, our majority owner. Mr. Scott is a former officer of ours. Based on the standards of the New York Stock Exchange, Inc. on which the common stock of our majority owner, Berkshire Hathaway, is listed, our Board of Directors has determined that Messrs. Buffett and Scott are not independent because of their ownership of our common stock. 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 that has an executive officer serving as a member of our Compensation Committee. See also Item 13 of this Form 10-K.

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

Beneficial Ownership

We are a consolidated subsidiary of Berkshire Hathaway. The balance of our common stock is owned by a Mr. Scott (along with family members and related entities) and Mr. Abel. The following table sets forth certain information regarding beneficial ownership of our shares of 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, 2010:

Name and Address of Beneficial Owner[1]	Number of Shares Beneficially Owned[2]	Percentage Of Class[2]
Berkshire Hathaway[3]	67,035,061	89.55%
Walter Scott, Jr.[4]	4,700,000	6.28%
David L. Sokol	-	-
Gregory E. Abel	595,940	0.80%
Douglas L. Anderson	-	-
Warren E. Buffett[5]	-	-
Patrick J. Goodman	-	-
Marc D. Hamburg[5]	-	-
Maureen E. Sammon	-	-
All directors and executive officers as a group (8 persons)	5,295,940	7.07%

(1) Unless otherwise indicated, each address is c/o MidAmerican Energy Holdings Company at 666 Grand Avenue, 29th Floor, Des Moines, Iowa 50309.

(2) Includes shares of 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.

(3) Such beneficial owner's address is 1440 Kiewit Plaza, Omaha, Nebraska 68131.

(4) Excludes 2,528,000 shares held by family members and family controlled trusts and corporations, or Scott Family Interests, as to which Mr. Scott disclaims beneficial ownership. Mr. Scott's address is 1000 Kiewit Plaza, Omaha, Nebraska 68131.

(5) Excludes 67,035,061 shares of common stock held by Berkshire Hathaway as to which Messrs. Buffett and Hamburg disclaim beneficial ownership.

The following table sets forth certain information regarding beneficial ownership of Class A and Class B shares of Berkshire Hathaway's 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, 2010:

Name and Address of Beneficial Owner[(1)]	**Number of Shares Beneficially Owned**[(2)]	**Percentage Of Class**[(2)]
Walter Scott, Jr.[(3)(4)]		
Class A	100	*
Class B	-	-
David L. Sokol[(4)]		
Class A	1,418	*
Class B	4,250	*
Gregory E. Abel[(4)]		
Class A	1	*
Class B	1,600	*
Douglas L. Anderson		
Class A	4	*
Class B	200	*
Warren E. Buffett[(5)]		
Class A	350,000	33.08%
Class B	75,076,600	10.10%
Patrick J. Goodman		
Class A	2	*
Class B	650	*
Marc D. Hamburg		
Class A	-	-
Class B	-	-
Maureen E. Sammon		
Class A	-	-
Class B	1,300	*
All directors and executive officers as a group (8 persons)		
Class A	351,525	33.22%
Class B	75,084,600	10.10%

* Less than 1%

(1) Unless otherwise indicated, each address is c/o MidAmerican Energy Holdings Company at 666 Grand Avenue, 29th Floor, Des Moines, Iowa 50309.

(2) 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.

(3) Does not include 10 Class A shares owned by Mr. Scott's wife. Mr. Scott's address is 1000 Kiewit Plaza, Omaha, Nebraska 68131.

(4) In accordance with a shareholders agreement, as amended on December 7, 2005, based on an assumed value for our common stock and the closing price of Berkshire Hathaway common stock on January 31, 2010, Mr. Scott and the Scott Family Interests and Mr. Abel would be entitled to exchange their shares of our common stock for either 14,191 and 1,170, respectively, shares of Berkshire Hathaway Class A stock or 21,278,294 and 1,754,370, respectively, 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. Scott and the Scott Family Interests would beneficially own 1.34% of the outstanding shares of Berkshire Hathaway Class A stock or 2.78% of the outstanding shares of Berkshire Hathaway Class B stock, and Mr. Abel would beneficially own less than 1% of the outstanding shares of either class of stock.

(5) Mr. Buffett's address is 1440 Kiewit Plaza, Omaha, Nebraska 68131.

Other Matters

Mr. Sokol's employment agreement gives him the right during the term of his employment to serve as a member of the Board of Directors and to nominate two additional directors.

Pursuant to a shareholders agreement, as amended on December 7, 2005, Mr. Scott or any of the Scott Family Interests and Mr. Abel are able to require Berkshire Hathaway to exchange any or all of their respective shares of our common stock for shares of Berkshire Hathaway common stock. The number of shares of Berkshire Hathaway stock to be exchanged is based on the fair market value of our common stock divided by the closing price of the Berkshire Hathaway 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. Transactions with Berkshire Hathaway require the approval of our Board of Directors.

At December 31, 2009 and 2008, Berkshire Hathaway and its affiliates held 11% mandatorily redeemable preferred securities due from certain of our wholly owned subsidiary trusts with liquidation preferences of $353 million and $1.09 billion, respectively. Principal repayments and interest expense on these securities totaled $734 million and $58 million, respectively, during 2009.

Director Independence

Based on the standards of the New York Stock Exchange, Inc., on which the common stock of our majority owner, Berkshire Hathaway, is listed, our Board of Directors has determined that none of our directors are considered independent because of their employment by Berkshire Hathaway or us or their ownership of our common stock.

Item 14. Principal Accountant Fees and Services

The following table shows the Company'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):

	2009	2008
Audit fees(1)	$ 5.3	$ 5.9
Audit-related fees(2)	0.7	1.1
Tax fees(3)	0.2	0.1
All other fees	-	-
Total aggregate fees billed	$ 6.2	$ 7.1

(1) Audit fees include fees for the audit of the Company's consolidated financial statements and interim reviews of the Company's quarterly financial statements, audit services provided in connection with required statutory audits of certain of MEHC's subsidiaries 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 subsidiary 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, state and international tax compliance, tax return preparation and tax audits.

The audit committee reviewed and approved the services rendered by the Deloitte Entities in and for fiscal 2009 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 the Company. 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

See Schedule I on page 161.
See Schedule II on page 165.

Schedules not listed above 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.

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

Not applicable.

Schedule I

MidAmerican Energy Holdings Company
Parent Company Only
Condensed Balance Sheets
As of December 31, 2009 and 2008
(Amounts in millions)

	2009	2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 17	$ 6
Other current assets	9	5
Total current assets	26	11
Investments in and advances to subsidiaries and joint ventures	16,102	15,783
Other investments	2,080	69
Equipment, net	20	32
Goodwill	1,289	1,268
Other assets	38	42
Total assets	$ 19,555	$ 17,205
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and other current liabilities	$ 288	$ 226
Short-term debt	50	216
Current portion of subordinated debt	188	734
Total current liabilities	526	1,176
Senior debt	5,371	5,121
Subordinated debt	402	587
Other long-term liabilities	677	111
Total liabilities	6,976	6,995
Equity:		
MEHC shareholders' equity:		
Common stock - 115 shares authorized, no par value, 75 shares issued and outstanding	-	-
Additional paid-in capital	5,453	5,455
Retained earnings	6,788	5,631
Accumulated other comprehensive income (loss), net	335	(879)
Total MEHC shareholders' equity	12,576	10,207
Noncontrolling interest	3	3
Total equity	12,579	10,210
Total liabilities and equity	$ 19,555	$ 17,205

The notes to the consolidated MEHC financial statements are an integral part of this financial statement schedule.

MidAmerican Energy Holdings Company
Parent Company Only (continued)
Condensed Statements of Operations
For the three years ended December 31, 2009
(Amounts in millions)

	2009	2008	2007
Revenue:			
Equity in undistributed earnings of subsidiary companies and joint ventures	$ 1,011	$ 1,770	$ 970
Dividends and distributions from subsidiary companies and joint ventures	495	304	483
Interest and other income	14	226	27
Total revenue	1,520	2,300	1,480
Costs and expenses:			
General and administration	172	34	15
Depreciation and amortization	1	-	2
Interest	445	487	459
Other	-	16	-
Total costs and expenses	618	537	476
Income before income tax benefit	902	1,763	1,004
Income tax benefit	(255)	(87)	(185)
Net income attributable to MEHC	$ 1,157	$ 1,850	$ 1,189

The notes to the consolidated MEHC financial statements are an integral part of this financial statement schedule.

Schedule I

MidAmerican Energy Holdings Company
Parent Company Only (continued)
Condensed Statements of Cash Flows
For the three years ended December 31, 2009
(Amounts in millions)

	2009	2008	2007
Cash flows from operating activities	$ (224)	$ (147)	$ (204)
Cash flows from investing activities:			
Decrease (increase) in advances to and investments in subsidiaries and joint ventures	1,255	(660)	317
Purchases of available-for-sale securities	(253)	(8)	(407)
Proceeds from sale of available-for-sale securities	8	3	399
Other, net	(1)	-	19
Net cash flows from investing activities	1,009	(665)	328
Cash flows from financing activities:			
Proceeds from senior and subordinated debt	250	1,649	1,539
Repayments of senior and subordinated debt	(734)	(1,803)	(784)
Purchases of senior debt	-	(138)	-
Proceeds from previously purchased senior debt	-	137	-
Net (repayments of) proceeds from revolving credit facility	(166)	216	(152)
Proceeds from issuances of common stock	-	-	10
Net purchases of common stock	(123)	-	-
Other, net	(1)	(8)	25
Net cash flows from financing activities	(774)	53	638
Net change in cash and cash equivalents	11	(759)	762
Cash and cash equivalents at beginning of year	6	765	3
Cash and cash equivalents at end of year	$ 17	$ 6	$ 765

The notes to the consolidated MEHC financial statements are an integral part of this financial statement schedule.

MIDAMERICAN ENERGY HOLDINGS COMPANY
NOTES TO CONDENSED FINANCIAL STATEMENTS

Incorporated by reference are MEHC and Subsidiaries Consolidated Statements of Changes in Equity for the three years ended December 31, 2009 in Part II, Item 8.

Basis of Presentation - The condensed financial information of MidAmerican Energy Holdings Company's ("MEHC") investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in and advances to subsidiaries and joint ventures are recorded in the Condensed Balance Sheets. The income from operations of the subsidiaries and joint ventures is reported on a net basis as equity in undistributed earnings of subsidiary companies and joint ventures in the Condensed Statements of Operations.

Other investments - In September 2008, MEHC reached a definitive agreement with BYD Company Limited ("BYD") to purchase 225 million shares, representing approximately a 10% interest in BYD, at a price of Hong Kong ("HK") $8 per share or HK$1.8 billion ($232 million). Established in 1995, BYD is a Hong Kong listed company with two main businesses: technology, including rechargeable batteries, chargers and cell phone design and assembly, and automobiles. BYD has seven production bases in Guangdong, Beijing, Shanghai and Xi'an and has offices in the United States, Europe, Japan, South Korea, India, Taiwan, Hong Kong and other regions. BYD has over 130,000 employees. The purchase was approved by an affirmative vote of the holders of two-thirds of the outstanding shares of BYD at an extraordinary general meeting held on December 3, 2008. The investment was made on July 30, 2009. MEHC's investment in BYD is accounted for as an available-for-sale security with changes in fair value recognized in accumulated other comprehensive income. The fair value of $1.986 billion as of December 31, 2009 compared to the acquisition cost of $232 million resulted in a pre-tax unrealized gain of $1.754 billion as of December 31, 2009.

Interest and other income - On December 17, 2008, MEHC and Constellation Energy Group, Inc. ("Constellation Energy") entered into a termination agreement, pursuant to which, among other things, the parties agreed to terminate the September 19, 2008 merger agreement. As a result of the termination, MEHC received a $175 million termination fee.

General and administration - In March 2009, 703,329 common stock options were exercised having an exercise price of $35.05 per share, or $25 million. Also in March 2009, MEHC purchased the shares issued from the options exercised for $148 million. As a result, MEHC recognized $125 million of stock-based compensation expense, including MEHC's share of payroll taxes, for the year ended December 31, 2009.

See the notes to the consolidated MEHC financial statements in Part II, Item 8 for other disclosures.

Schedule II

MIDAMERICAN ENERGY HOLDINGS COMPANY
CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE THREE YEARS ENDED DECEMBER 31, 2009
(Amounts in millions)

Column A Description	Column B Balance at Beginning of Year	Column C Charged to Income	Column C Acquisition Reserves	Column D Deductions	Column E Balance at End of Year
Reserves Deducted From Assets To Which They Apply:					
Reserve for uncollectible accounts receivable:					
Year ended 2009	$ 24	$ 28	$ 1	$ (28)	$ 25
Year ended 2008	22	32	-	(30)	24
Year ended 2007	30	24	-	(32)	22
Reserves Not Deducted From Assets(1):					
Year ended 2009	$ 9	$ 4	$ -	$ (4)	$ 9
Year ended 2008	12	2	-	(5)	9
Year ended 2007	12	3	-	(3)	12

The notes to the consolidated MEHC financial statements are an integral part of this financial statement schedule.

(1) Reserves not deducted from assets relate primarily to estimated liabilities for losses retained by MEHC for workers compensation, public liability and property damage claims.

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 1st day of March 2010.

MIDAMERICAN ENERGY HOLDINGS COMPANY

/s/ Gregory E. Abel*
Gregory E. Abel
President and Chief Executive Officer
(principal executive officer)

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

Signature	Title	Date
/s/ David L. Sokol* David L. Sokol	Chairman of the Board and Director	March 1, 2010
/s/ Gregory E. Abel* Gregory E. Abel	President, Chief Executive Officer and Director (principal executive officer)	March 1, 2010
/s/ Patrick J. Goodman* Patrick J. Goodman	Senior Vice President and Chief Financial Officer (principal financial and accounting officer)	March 1, 2010
/s/ Walter Scott, Jr.* Walter Scott, Jr.	Director	March 1, 2010
/s/ Marc D. Hamburg* Marc D. Hamburg	Director	March 1, 2010
/s/ Warren E. Buffett* Warren E. Buffett	Director	March 1, 2010
* By: /s/ Douglas L. Anderson Douglas L. Anderson	Attorney-in-Fact	March 1, 2010

SUPPLEMENTAL INFORMATION TO BE FURNISHED WITH REPORTS FILED PURSUANT TO SECTION 15(D) OF THE ACT BY REGISTRANTS WHICH HAVE NOT REGISTERED SECURITIES PURSUANT TO SECTION 12 OF THE ACT

No annual report to security holders covering MidAmerican Energy Holdings Company's last fiscal year or proxy material has been sent to security holders.

EXHIBIT INDEX

Exhibit No.	Description
3.1	Second Amended and Restated Articles of Incorporation of MidAmerican Energy Holdings Company effective March 2, 2006 (incorporated by reference to Exhibit 3.1 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2005).
3.2	Amended and Restated Bylaws of MidAmerican Energy Holdings Company (incorporated by reference to Exhibit 3.2 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2005).
4.1	Indenture, dated as of October 4, 2002, by and between MidAmerican Energy Holdings Company and The Bank of New York, Trustee, relating to the 5.875% Senior Notes due 2012 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Holdings Company Registration Statement No. 333-101699 dated December 6, 2002).
4.2	First Supplemental Indenture, dated as of October 4, 2002, by and between MidAmerican Energy Holdings Company and The Bank of New York, Trustee, relating to the 5.875% Senior Notes due 2012 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Holdings Company Registration Statement No. 333-101699 dated December 6, 2002).
4.3	Second Supplemental Indenture, dated as of May 16, 2003, by and between MidAmerican Energy Holdings Company and The Bank of New York, Trustee, relating to the 3.50% Senior Notes due 2008 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Holdings Company Registration Statement No. 333-105690 dated May 23, 2003).
4.4	Third Supplemental Indenture, dated as of February 12, 2004, by and between MidAmerican Energy Holdings Company and The Bank of New York, Trustee, relating to the 5.00% Senior Notes due 2014 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Holdings Company Registration Statement No. 333-113022 dated February 23, 2004).
4.5	Fourth Supplemental Indenture, dated as of March 24, 2006, by and between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., Trustee, relating to the 6.125% Senior Bonds due 2036 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated March 28, 2006).
4.6	Fifth Supplemental Indenture, dated as of May 11, 2007, by and between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., Trustee, relating to the 5.95% Senior Bonds due 2037 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated May 11, 2007).
4.7	Sixth Supplemental Indenture, dated as of August 28, 2007, by and between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., Trustee, relating to the 6.50% Senior Bonds due 2037 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated August 28, 2007).
4.8	Seventh Supplemental Indenture, dated as of March 28, 2008, by and between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., as Trustee, relating to the 5.75% Senior Notes due 2018 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated March 28, 2008).
4.9	Eighth Supplemental Indenture, dated as of July 7, 2009, by and between MidAmerican Energy Holdings Company and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 3.15% Senior Notes due 2012 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated July 7, 2009).

Exhibit No.	Description
4.10	Indenture dated as of February 26, 1997, by and between MidAmerican Energy Holdings Company and the Bank of New York, Trustee relating to the 6¼% Convertible Junior Subordinated Debentures due 2012 (incorporated by reference to Exhibit 10.129 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 1995).
4.11	Indenture, dated as of October 15, 1997, by and between MidAmerican Energy Holdings Company and IBJ Schroder Bank & Trust Company, Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated October 23, 1997).
4.12	Form of Second Supplemental Indenture, dated as of September 22, 1998 by and between MidAmerican Energy Holdings Company and IBJ Schroder Bank & Trust Company, Trustee, relating to the 8.48% Senior Notes in the principal amount of $475,000,000 due 2028 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated September 17, 1998).
4.13	Indenture, dated as of March 14, 2000, by and between MidAmerican Energy Holdings Company and the Bank of New York, Trustee (incorporated by reference to Exhibit 4.9 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K/A for the year ended December 31, 1999).
4.14	Indenture, dated as of March 12, 2002, by and between MidAmerican Energy Holdings Company and the Bank of New York, Trustee (incorporated by reference to Exhibit 4.11 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2001).
4.15	Amended and Restated Declaration of Trust of MidAmerican Capital Trust III, dated as of August 16, 2002 (incorporated by reference to Exhibit 4.14 to the MidAmerican Energy Holdings Company Registration Statement No. 333-101699 dated December 6, 2002).
4.16	Amended and Restated Declaration of Trust of MidAmerican Capital Trust II, dated as of March 12, 2002 (incorporated by reference to Exhibit 4.15 to the MidAmerican Energy Holdings Company Registration Statement No. 333-101699 dated December 6, 2002).
4.17	Amended and Restated Declaration of Trust of MidAmerican Capital Trust I, dated as of March 14, 2000 (incorporated by reference to Exhibit 4.16 to the MidAmerican Energy Holdings Company Registration Statement No. 333-101699 dated December 6, 2002).
4.18	Indenture, dated as of August 16, 2002, by and between MidAmerican Energy Holdings Company and the Bank of New York, Trustee (incorporated by reference to Exhibit 4.17 to the MidAmerican Energy Holdings Company Registration Statement No. 333-101699 dated December 6, 2002).
4.19	Trust Indenture, dated as of November 27, 1995, by and between CE Casecnan Water and Energy Company, Inc. and Chemical Trust Company of California, Trustee (incorporated by reference to Exhibit 4.1 to the CE Casecnan Water and Energy Company, Inc. Registration Statement on Form S-4 dated January 25, 1996).
4.20	Indenture and First Supplemental Indenture, dated March 11, 1999, by and between MidAmerican Funding, LLC and IBJ Whitehall Bank & Trust Company, Trustee, relating to the $700 million Senior Notes and Bonds (incorporated by reference to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 1998).
4.21	Second Supplemental Indenture, dated as of March 1, 2001, by and between MidAmerican Funding, LLC and The Bank of New York, Trustee (incorporated by reference to Exhibit 4.4 to the MidAmerican Funding, LLC Registration Statement on Form S-3, Registration No. 333-56624).
4.22	Indenture dated as of December 1, 1996, by and between MidAmerican Energy Company and the First National Bank of Chicago, Trustee (incorporated by reference to Exhibit 4(1) to the MidAmerican Energy Company Registration Statement on Form S-3, Registration No. 333-15387).

Exhibit No.	Description
4.23	First Supplemental Indenture, dated as of February 8, 2002, by and between MidAmerican Energy Company and The Bank of New York, Trustee (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2004, Commission File No. 333-15387).
4.24	Second Supplemental Indenture, dated as of January 14, 2003, by and between MidAmerican Energy Company and The Bank of New York, Trustee (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2004, Commission File No. 333-15387).
4.25	Third Supplemental Indenture, dated as of October 1, 2004, by and between MidAmerican Energy Company and The Bank of New York, Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2004, Commission File No. 333-15387).
4.26	Fourth Supplemental Indenture, dated November 1, 2005, by and between MidAmerican Energy Company and the Bank of New York Trust Company, NA, Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2005).
4.27	Fiscal Agency Agreement, dated as of October 15, 2002, by and between Northern Natural Gas Company and J.P. Morgan Trust Company, National Association, Fiscal Agent, relating to the $300,000,000 in principal amount of the 5.375% Senior Notes due 2012 (incorporated by reference to Exhibit 10.47 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2003).
4.28	Trust Indenture, dated as of August 13, 2001, among Kern River Funding Corporation, Kern River Gas Transmission Company and JP Morgan Chase Bank, Trustee, relating to the $510,000,000 in principal amount of the 6.676% Senior Notes due 2016 (incorporated by reference to Exhibit 10.48 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2003).
4.29	Third Supplemental Indenture, dated as of May 1, 2003, among Kern River Funding Corporation, Kern River Gas Transmission Company and JPMorgan Chase Bank, Trustee, relating to the $836,000,000 in principal amount of the 4.893% Senior Notes due 2018 (incorporated by reference to Exhibit 10.49 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2003).
4.30	Trust Deed, dated December 15, 1997 among CE Electric UK Funding Company, AMBAC Insurance UK Limited and The Law Debenture Trust Corporation, p.l.c., Trustee (incorporated by reference to Exhibit 99.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated March 30, 2004).
4.31	Insurance and Indemnity Agreement, dated December 15, 1997 by and between CE Electric UK Funding Company and AMBAC Insurance UK Limited (incorporated by reference to Exhibit 99.2 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated March 30, 2004).
4.32	Supplemental Agreement to Insurance and Indemnity Agreement, dated September 19, 2001, by and between CE Electric UK Funding Company and AMBAC Insurance UK Limited (incorporated by reference to Exhibit 99.3 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated March 30, 2004).
4.33	Fiscal Agency Agreement, dated as of July 15 2008, by and between Northern Natural Gas Company and The Bank New York Mellon Trust Company, National Association, Fiscal Agent, relating to the $200,000,000 in principal amount of the 5.75% Senior Notes due 2018.
4.34	Fiscal Agency Agreement, dated as of May 24, 1999, by and between Northern Natural Gas Company and Chase Bank of Texas, National Association, Fiscal Agent, relating to the $250,000,000 in principal amount of the 7.00% Senior Notes due 2011 (incorporated by reference to Exhibit 10.70 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).

Exhibit No.	Description
4.35	Trust Indenture, dated as of September 10, 1999, by and between Cordova Funding Corporation and Chase Manhattan Bank and Trust Company, National Association, Trustee, relating to the $225,000,000 in principal amount of the 8.75% Senior Secured Bonds due 2019 (incorporated by reference to Exhibit 10.71 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.36	Trust Deed, dated as of February 4, 1998 among Yorkshire Power Finance Limited, Yorkshire Power Group Limited and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 7.25% Guaranteed Bonds due 2028 (incorporated by reference to Exhibit 10.74 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.37	First Supplemental Trust Deed, dated as of October 1, 2001, among Yorkshire Power Finance Limited, Yorkshire Power Group Limited and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 7.25% Guaranteed Bonds due 2028 (incorporated by reference to Exhibit 10.75 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.38	Third Supplemental Trust Deed, dated as of October 1, 2001, among Yorkshire Electricity Distribution plc, Yorkshire Electricity Group plc and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 9.25% Bonds due 2020 (incorporated by reference to Exhibit 10.76 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.39	Indenture, dated as of February 1, 2000, among Yorkshire Power Finance 2 Limited, Yorkshire Power Group Limited and The Bank of New York, Trustee (incorporated by reference to Exhibit 10.78 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.40	First Supplemental Trust Deed, dated as of September 27, 2001, among Northern Electric Finance plc, Northern Electric plc, Northern Electric Distribution Limited and The Law Debenture Trust Corporation p.l.c., Trustee, relating to the £100,000,000 in principal amount of the 8.875% Guaranteed Bonds due 2020 (incorporated by reference to Exhibit 10.81 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.41	Trust Deed, dated as of January 17, 1995, by and between Yorkshire Electricity Group plc and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 9 1/4% Bonds due 2020 (incorporated by reference to Exhibit 10.83 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.42	Master Trust Deed, dated as of October 16, 1995, by and between Northern Electric Finance plc, Northern Electric plc and The Law Debenture Trust Corporation p.l.c., Trustee, relating to the £100,000,000 in principal amount of the 8.875% Guaranteed Bonds due 2020 (incorporated by reference to Exhibit 10.70 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2004).
4.43	Fiscal Agency Agreement, dated April 14, 2005, by and between Northern Natural Gas Company and J.P. Morgan Trust Company, National Association, Fiscal Agent, relating to the $100,000,000 in principal amount of the 5.125% Senior Notes due 2015 (incorporated by reference to Exhibit 99.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated April 18, 2005).
4.44	Trust Deed dated May 5, 2005 among Northern Electric Finance plc, Northern Electric Distribution Limited, Ambac Assurance UK Limited and HSBC Trustee (C.I.) Limited (incorporated by reference to Exhibit 99.1 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).

Exhibit No.	Description
4.45	Reimbursement and Indemnity Agreement dated May 5, 2005 among Northern Electric Finance plc, Northern Electric Distribution Limited and Ambac Assurance UK Limited (incorporated by reference to Exhibit 99.2 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.46	Trust Deed, dated May 5, 2005 among Yorkshire Electricity Distribution plc, Ambac Assurance UK Limited and HSBC Trustee (C.I.) Limited (incorporated by reference to Exhibit 99.3 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.47	Reimbursement and Indemnity Agreement, dated May 5, 2005 between Yorkshire Electricity Distribution plc and Ambac Assurance UK Limited (incorporated by reference to Exhibit 99.4 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.48	Supplemental Trust Deed, dated May 5, 2005 among CE Electric UK Funding Company, Ambac Assurance UK Limited and The Law Debenture Trust Corporation plc (incorporated by reference to Exhibit 99.5 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.49	Second Supplemental Agreement to Insurance and Indemnity Agreement, dated May 5, 2005 by and between CE Electric UK Funding Company and Ambac Assurance UK Limited (incorporated by reference to Exhibit 99.6 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.50	Shareholders Agreement, dated as of March 14, 2000 (incorporated by reference to Exhibit 4.19 to the MidAmerican Energy Holdings Company Registration Statement No. 333-101699 dated December 6, 2002).
4.51	Amendment No. 1 to Shareholders Agreement, dated December 7, 2005 (incorporated by reference to Exhibit 4.17 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2005).
4.52	Equity Commitment Agreement, dated as of March 1, 2006, by and between Berkshire Hathaway Inc. and MidAmerican Energy Holdings Company (incorporated by reference to Exhibit 10.72 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2005).
4.53	Fiscal Agency Agreement, dated February 12, 2007, by and between Northern Natural Gas Company and Bank of New York Trust Company, N.A., Fiscal Agent, relating to the $150,000,000 in principal amount of the 5.80% Senior Bonds due 2037 (incorporated by reference to Exhibit 99.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated February 12, 2007).
4.54	Indenture, dated as of October 1, 2006, by and between MidAmerican Energy Company and the Bank of New York Trust Company, N.A., Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
4.55	First Supplemental Indenture, dated as of October 6, 2006, by and between MidAmerican Energy Company and the Bank of New York Trust Company, N.A., Trustee (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
4.56	Second Supplemental Indenture, dated June 29, 2007, by and between MidAmerican Energy Company and The Bank of New York Trust Company, N.A., Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated June 29, 2007).
4.57	Third Supplemental Indenture, dated March 25, 2008, by and between MidAmerican Energy Company and The Bank of New York Trust Company, Trustee, relating to the 5.3% Notes due 2018 (incorporated by reference to Exhibit 4.1 to MidAmerican Energy Company Current Report on Form 8-K dated March 25, 2008).

Exhibit No.	Description
4.58	Mortgage and Deed of Trust dated as of January 9, 1989, between PacifiCorp and The Bank of New York Mellon Trust Company, N.A. (formerly known as JP Morgan Chase Bank and The Chase Manhattan Bank), Trustee, incorporated by reference to Exhibit 4-E to PacifiCorp's Form 8-B, File No. 1-5152, as supplemented and modified by 23 Supplemental Indentures, each incorporated by reference, as follows:

Exhibit Number	PacifiCorp 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

10.1	Amended and Restated Employment Agreement, dated February 25, 2008, by and between MidAmerican Energy Holdings Company and David L. Sokol (incorporated by reference to Exhibit 10.1 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2007).
10.2	Incremental Profit Sharing Plan, dated February 16, 2009, by and between MidAmerican Energy Holdings Company and David L. Sokol (incorporated by reference to Exhibit 10.3 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2008).
10.3	Amended and Restated Employment Agreement, dated February 25, 2008, by and between MidAmerican Energy Holdings Company and Gregory E. Abel (incorporated by reference to Exhibit 10.3 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2007).
10.4	Incremental Profit Sharing Plan, dated February 10, 2009, by and between MidAmerican Energy Holdings Company and Gregory E. Abel (incorporated by reference to Exhibit 10.6 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2008).
10.5	Amended and Restated Employment Agreement, dated February 25, 2008, by and between MidAmerican Energy Holdings Company and Patrick J. Goodman (incorporated by reference to Exhibit 10.5 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2007).

Exhibit No.	Description
10.6	Amended and Restated Casecnan Project Agreement, dated June 26, 1995, between the National Irrigation Administration and CE Casecnan Water and Energy Company Inc. (incorporated by reference to Exhibit 10.1 to the CE Casecnan Water and Energy Company, Inc. Registration Statement on Form S-4 dated January 25, 1996).
10.7	Supplemental Agreement, dated as of September 29, 2003, by and between CE Casecnan Water and Energy Company, Inc. and the Philippines National Irrigation Administration (incorporated by reference to Exhibit 98.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated October 15, 2003).
10.8	CalEnergy Company, Inc. Voluntary Deferred Compensation Plan, effective December 1, 1997, First Amendment, dated as of August 17, 1999, and Second Amendment effective March 14, 2000 (incorporated by reference to Exhibit 10.50 to the MidAmerican Energy Holdings Company Registration Statement No. 333-101699 dated December 6, 2002).
10.9	MidAmerican Energy Holdings Company Executive Voluntary Deferred Compensation Plan restated effective as of January 1, 2007 (incorporated by reference to Exhibit 10.9 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2007).
10.10	MidAmerican Energy Company First Amended and Restated Supplemental Retirement Plan for Designated Officers dated as of May 10, 1999 amended on February 25, 2008 to be effective as of January 1, 2005 (incorporated by reference to Exhibit 10.10 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2007).
10.11	MidAmerican Energy Holdings Company Long-Term Incentive Partnership Plan as Amended and Restated January 1, 2007 (incorporated by reference to Exhibit 10.11 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2007).
10.12	Amended and Restated Credit Agreement, dated as of July 6, 2006, by and among MidAmerican Energy Holdings Company, as Borrower, The Banks and Other Financial Institutions Parties Hereto, as Banks, JPMorgan Chase Bank, N.A., as L/C Issuer, Union Bank of California, N.A., as Administrative Agent, The Royal Bank of Scotland PLC, as Syndication Agent, and ABN Amro Bank N.V., JPMorgan Chase Bank, N.A. and BNP Paribas as Co-Documentation Agents (incorporated by reference to Exhibit 99.1 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.13	First Amendment, dated as of April 15, 2009, to the Amended and Restated Credit Agreement, dated as of July 6, 2006, by and among MidAmerican Energy Holdings Company, as Borrower, The Banks and Other Financial Institutions Parties Hereto, as Banks, JPMorgan Chase Bank, N.A., as L/C Issuer, Union Bank of California, N.A., as Administrative Agent, The Royal Bank of Scotland PLC, as Syndication Agent, and ABN Amro Bank N.V., JPMorgan Chase Bank, N.A. and BNP Paribas as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to the MidAmerican Energy Holdings Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
10.14	Amended and Restated Credit Agreement, dated as of July 6, 2006, among MidAmerican Energy Company, the Lending Institutions Party Hereto, as Banks, Union Bank of California, N.A., as Syndication Agent, JPMorgan Chase Bank, N.A., as Administrative Agent, and The Royal Bank of Scotland plc, ABN AMRO Bank N.V. and BNP Paribas as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).

Exhibit No.	Description
10.15	First Amendment, dated as of April 15, 2009, to the Amended and Restated Credit Agreement, dated as of July 6, 2006, by and among MidAmerican Energy Company, the Lending Institutions Party Hereto, as Banks, Union Bank of California, N.A., as Syndication Agent, JPMorgan Chase Bank, N.A., as Administrative Agent, and The Royal Bank of Scotland plc, ABN AMRO Bank N.V. and BNP Paribas as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
10.16	$700,000,000 Credit Agreement dated as of October 23, 2007 among PacifiCorp, The Banks Party thereto, The Royal Bank of Scotland plc, as Syndication Agent, and Union Bank of California, N.A., as Administrative Agent (incorporated by reference to Exhibit 99 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended September 30, 2007).
10.17	First Amendment, dated as of April 15, 2009, to the $700,000,000 Credit Agreement dated as of October 23, 2007 among PacifiCorp, The Banks Party thereto, The Royal Bank of Scotland plc, as Syndication Agent, and Union Bank of California, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
10.18	$800,000,000 Amended and Restated Credit Agreement dated as of July 6, 2006 among PacifiCorp, The Banks Party thereto, The Royal Bank of Scotland plc, as Syndication Agent, and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by Reference to Exhibit 99 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.19	First Amendment, dated as of April 15, 2009, to the $800,000,000 Amended and Restated Credit Agreement dated as of July 6, 2006 among PacifiCorp, The Banks Party thereto, The Royal Bank of Scotland plc, as Syndication Agent, and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).
10.20	£100,000,000 Facility Agreement, dated April 4, 2005 among CE Electric UK Funding Company, the subsidiaries of CE Electric UK Funding Company listed in Part 1 of Schedule 1, Lloyds TSB Bank plc and The Royal Bank of Scotland plc (incorporated by reference to Exhibit 99.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated April 20, 2005).
10.21	Summary of Key Terms of Compensation Arrangements with MidAmerican Energy Holdings Company Named Executive Officers and Directors.
14.1	MidAmerican Energy Holdings Company Code of Ethics for Chief Executive Officer, Chief Financial Officer and Other Covered Officers (incorporated by reference to Exhibit 14.1 to the MidAmerican Energy Holdings Company Annual Report on Form 10-K for the year ended December 31, 2003).
21.1	Subsidiaries of the Registrant.
23.1	Consent of Deloitte & Touche LLP.
24.1	Power of Attorney.
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.

EXHIBIT 21.1

MIDAMERICAN ENERGY HOLDINGS COMPANY
SUBSIDIARIES AND JOINT VENTURES

Pursuant to Item 601(b)(21)(ii) of Regulation S-K, we have omitted dormant subsidiaries (all of which, when considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary as of the end of our last fiscal year).

MidAmerican Funding, LLC	Iowa
MHC Inc.	Iowa
MidAmerican Energy Company	Iowa
CBEC Railway Inc.	Iowa
InterCoast Capital Company	Delaware
InterCoast Energy Company	Delaware
Cimmred Leasing Company	South Dakota
MHC Investment Company	South Dakota
MWR Capital Inc.	South Dakota
Midwest Capital Group, Inc.	Iowa
Dakota Dunes Development Company	Iowa
Two Rivers Inc.	South Dakota
MEC Construction Services Co.	Iowa
CE Electric UK Funding Company	England
CalEnergy Gas (Holdings) Limited	England
CalEnergy Gas Limited	England
CalEnergy Gas (Australia) Limited	England
CalEnergy Resources Limited	England
CalEnergy Resources (Poland) sp.z.o.o.	Poland
CalEnergy Resources (Australia) Limited	England
CE Electric (Ireland) Limited	Republic of Ireland
CE Electric UK Holdings	England
CE Electric UK Limited	England
CE UK Gas Holdings Limited	England
Integrated Utility Services Limited	England
Integrated Utility Services Limited	Republic of Ireland
Northern Electric plc	England
Northern Electric Distribution Limited	England
Northern Electric Finance plc	England
Northern Electric & Gas Limited	England
Northern Electric Properties Limited	England
Northern Transport Finance Limited	England
Vehicle Lease and Service Limited	England
Yorkshire Electricity Distribution plc	England
Yorkshire Electricity Group plc	England
Yorkshire Power Finance Limited	Cayman Islands
Yorkshire Power Group Limited	England
HomeServices of America, Inc.	Delaware
Allerton Capital, Ltd.	Iowa
Arizona Home Services, LLC	Arizona
California Title Company	California
Capitol Intermediary Company	Nebraska
Capitol Land Exchange, Inc.	Nebraska
Capitol Title Company	Nebraska
CBSHOME Real Estate Company	Nebraska
CBSHOME Real Estate of Iowa, Inc.	Delaware
CBSHOME Relocation Services, Inc.	Nebraska
Champion Realty, Inc.	Maryland
Chancellor Title Services, Inc.	Maryland

Columbia Title of Florida, Inc.	Florida
Cornerstone Title Company, L.L.C.	Georgia
Edina Financial Services, Inc.	Minnesota
Edina Realty, Inc.	Minnesota
Edina Realty Referral Network, Inc.	Minnesota
Edina Realty Relocation, Inc.	Minnesota
Edina Realty Title, Inc.	Minnesota
Esslinger-Wooten-Maxwell, Inc.	Florida
E-W-M Referral Services, Inc.	Florida
FFR, Inc.	Iowa
First Realty, Ltd.	Iowa
First Reserve Insurance, Inc.	Florida
For Rent, Inc.	Arizona
Heritage Title Services, LLC	Georgia
HMSV Financial Services, Inc.	Delaware
HN Heritage Title Holdings, LLC	Georgia
HN Real Estate Group, L.L.C.	Georgia
HN Real Estate Group, N.C., Inc.	North Carolina
HN Referral Corporation	Georgia
Home Services Referral Network, LLC	Indiana
HomeServices Financial, LLC	Delaware
HomeServices Financial Holdings, Inc.	Delaware
HomeServices Financial-Iowa, LLC	Delaware
HomeServices Lending, LLC	Delaware
HomeServices Insurance, Inc.	Nebraska
HomeServices Insurance Agency, Inc.	Delaware
HomeServices of Alabama, Inc.	Delaware
HomeServices of California, Inc.	Delaware
HomeServices of Florida, Inc.	Florida
HomeServices of Iowa, Inc.	Delaware
HomeServices of Kentucky, Inc.	Kentucky
HomeServices of Kentucky Insurance, Inc.	Delaware
HomeServices of Kentucky Real Estate Academy, LLC	Kentucky
HomeServices of Nebraska, Inc.	Delaware
HomeServices of Nebraska Insurance, Inc.	Delaware
HomeServices of the Carolinas, Inc.	Delaware
HomeServices Relocation, LLC	Delaware
HSR Equity Funding, Inc.	Delaware
Huff Commercial Group, LLC	Kentucky
Huff Realty Insurance, Inc.	Delaware
Huff-Drees Realty, Inc.	Ohio
IMO Co., Inc.	Missouri
Insurance South, LLC	Georgia
Iowa Realty Co., Inc.	Iowa
Iowa Realty Insurance Agency, Inc.	Iowa
Iowa Title Company	Iowa
Iowa Title Linn County II, LLC	Iowa
JBRC, Inc.	Kentucky
J.D. Reece Mortgage Company	Kansas
Jim Huff Realty, Inc.	Kentucky
JRHBW Realty, Inc.	Alabama
J. S. White & Associates, Inc.	Alabama
Kansas City Title, Inc.	Kansas
Kentucky Residential Referral Services, LLC	Kentucky
Larabee School of Real Estate and Insurance, Inc.	Nebraska
Lincoln Title Company, LLC	Nebraska
Long Title Agency, LLC	Arizona

Meridian Title Services, LLC	Georgia
Mid-America Referral Network, Inc.	Kansas
Midland Escrow Services, Inc.	Iowa
MortgageSouth, LLC	Alabama
Nebraska Land Title and Abstract Company	Nebraska
PHX Mortgage Advisors, LLC	Delaware
Pickford Escrow Company, Inc.	California
Pickford Golden State Member, LLC	California
Pickford Holdings LLC	California
Pickford North County LP	California
Pickford Real Estate, Inc.	California
Pickford Realty, Ltd.	California
Pickford Services Company	California
Plaza Financial Services, LLC	Kansas
Plaza Mortgage Services, LLC	Kansas
Preferred Carolinas Realty, Inc.	North Carolina
Preferred Carolinas Title Agency, LLC	North Carolina
Professional Referral Organization, Inc.	Maryland
Real Estate Links, LLC	Illinois
Real Estate Referral Network, Inc.	Nebraska
Reece & Nichols Alliance, Inc.	Kansas
Reece & Nichols Insurance, Inc.	Delaware
Reece & Nichols Realtors, Inc.	Kansas
Referral Company of North Carolina, Inc.	North Carolina
RHL Referral Company, LLC	Arizona
Roberts Brothers, Inc.	Alabama
Roy H. Long Realty Co., Inc.	Arizona
San Diego PCRE, Inc.	California
Semonin Realtors, Inc.	Delaware
Southwest Relocation, LLC	Arizona
The Escrow Firm, Inc.	California
The Referral Company	Iowa
TITLE INFO NOW, LLC	Minnesota
TitleSouth, LLC	Alabama
Township Title Services, LLC	Georgia
Traditions Title Agency, LLC	Ohio
United Settlement Services, LC	Iowa
York Simpson Underwood, LLC	North Carolina
CE Generation, LLC	Delaware
CalEnergy Operating Corporation	Delaware
California Energy Development Corporation	Delaware
California Energy Yuma Corporation	Utah
CE Salton Sea Inc.	Delaware
CE Texas Power, LLC	Delaware
CE Texas Resources, LLC	Delaware
CE Turbo LLC	Delaware
Conejo Energy Company	California
Del Ranch Company	California
Desert Valley Company	California
ElmoreCompany	California
Falcon Power Operating Company	Texas
CE Gen Oil Company	Texas
CE Gen Pipeline Corporation	Texas
CE Gen Power Corporation	Texas
Fish Lake Power LLC	Delaware
FSRI Holdings, Inc	Texas
Imperial Magma LLC	Delaware

CE Leathers Company	California
Magma Land Company I	Nevada
Magma Power Company	Nevada
Niguel Energy Company	California
North Country Gas Pipeline Corporation	New York
Power Resources, Ltd.	Texas
Salton Sea Brine Processing Company	California
Salton Sea Funding Corporation	Delaware
Salton Sea Power Company	Nevada
Salton Sea Power Generation Company	California
Salton Sea Power L.L.C.	Delaware
Salton Sea Royalty Company	Delaware
San Felipe Energy Company	California
Saranac Energy Company, Inc.	Delaware
Saranac Power Partners, LP	Delaware
SECI Holdings, Inc.	Delaware
VPC Geothermal LLC	Delaware
Vulcan Power Company	Nevada
Vulcan/BN Geothermal Power Company	Nevada
Yuma Cogeneration Associates	Arizona
BG Energy Holding LLC	Delaware
BG Energy LLC	Delaware
CalEnergy Capital Trust II	Delaware
CalEnergy Capital Trust III	Delaware
CalEnergy Generation Operating Company	Delaware
CalEnergy International Services, Inc.	Delaware
CalEnergy Investments C.V.	Netherlands
CalEnergy Minerals, LLC	Delaware
CalEnergy Pacific Holdings Corp.	Delaware
CalEnergy U.K. Inc.	Delaware
CE Casecnan Ltd.	Bermuda
CE Casecnan II, Inc.	Philippines
CE Casecnan Water and Energy Company, Inc.	Philippines
CE Electric (NY), Inc.	Delaware
CE Electric, Inc.	Delaware
CE Exploration Company	Delaware
CE Geothermal, Inc.	Delaware
CE Insurance Services Limited	Isle of Man
CE International Investments, Inc.	Delaware
CE Philippines II, Inc.	Philippines
CE Philippines Ltd.	Bermuda
CE Power, Inc.	Delaware
Cordova Energy Company, LLC	Delaware
Cordova Funding Corporation	Delaware
Kern River Funding Corporation	Delaware
Kern River Gas Transmission Company	Texas
KR Acquisition 1, LLC	Delaware
KR Acquisition 2, LLC	Delaware
KR Holding, LLC	Delaware
Magma Netherlands B.V.	Netherlands
MEHC Investment, Inc.	South Dakota
MidAmerican Capital Trust II	Delaware
MidAmerican Capital Trust III	Delaware
MEHC Insurance Services Ltd.	Vermont
MEHC America Transco, LLC	Delaware
MEHC Texas Transco, LLC	Delaware
Electric Transmission America, LLC	Delaware

Prairie Wind Transmission, LLC	Delaware
Tallgrass Transmission, LLC	Delaware
Electric Transmission Texas, LLC	Delaware
MidAmerican Energy Machining Services LLC	Delaware
NNGC Acquisition, LLC	Delaware
Northern Natural Gas Company	Delaware
PPW Holdings LLC	Delaware
PacifiCorp	Oregon
Energy West Mining Company	Utah
PacifiCorp Investment Management, Inc.	Oregon
Glenrock Coal Company	Wyoming
Interwest Mining Company	Oregon
Pacific Minerals, Inc.	Wyoming
PacifiCorp Environmental Remediation Company	Delaware
Trapper Mining Inc.	Delaware
Bridger Coal Company	Wyoming
Quad Cities Energy Company	Iowa
Salton Sea Minerals Corp.	Delaware
S.W. Hydro, Inc.	Delaware
Wailuku Holding Company, LLC	Delaware
Wailuku River Hydroelectric Power Company	Hawaii
Wailuku River Hydroelectric Limited Partnership	Hawaii

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-147957 on Form S-8 of our report dated March 1, 2010, relating to the financial statements and financial statement schedules of MidAmerican Energy Holdings Company, appearing in this Annual Report on Form 10-K of MidAmerican Energy Holdings Company for the year ended December 31, 2009.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
March 1, 2010

EXHIBIT 24.1

POWER OF ATTORNEY

The undersigned, a member of the Board of Directors or an officer of MIDAMERICAN ENERGY HOLDINGS COMPANY, an Iowa corporation (the “Company”), hereby constitutes and appoints Douglas L. Anderson and Paul J. Leighton and each of them, as his/her true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for and in his/her stead, in any and all capacities, to sign on his/her behalf the Company’s Annual Report on Form 10-K for the fiscal year ending December 31, 2009 and to execute any amendments thereto and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission and applicable stock exchanges, with the full power and authority to do and perform each and every act and thing necessary or advisable to all intents and purposes as he/she might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent, or his/her substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Executed as of February 26, 2010

/s/ David L. Sokol
DAVID L. SOKOL

/s/ Gregory E. Abel
GREGORY E. ABEL

/s/ Patrick J. Goodman
PATRICK J. GOODMAN

/s/ Warren E. Buffett
WARREN E. BUFFETT

/s/ Marc D. Hamburg
MARC D. HAMBURG

/s/ Walter Scott, Jr.
WALTER SCOTT, JR.

EXHIBIT 31.1

**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 MidAmerican Energy Holdings Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2010

/s/ Gregory E. Abel
Gregory E. Abel
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.2

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

I, Patrick J. Goodman, certify that:

1. I have reviewed this Annual Report on Form 10-K of MidAmerican Energy Holdings Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2010

/s/ Patrick J. Goodman
Patrick J. Goodman
Senior Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 32.1

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

I, Gregory E. Abel, Chairman and Chief Executive Officer of MidAmerican Energy Holdings Company (the “Company”), 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, 2009 (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 results of operations of the Company.

Date: March 1, 2010

/s/ Gregory E. Abel
Gregory E. Abel
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.2

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

I, Patrick J. Goodman, Senior Vice President and Chief Financial Officer of MidAmerican Energy Holdings Company (the "Company"), 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, 2009 (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 results of operations of the Company.

Date: March 1, 2010

/s/ Patrick J. Goodman
Patrick J. Goodman
Senior Vice President and Chief Financial Officer
(principal financial officer)