Prospectus

MIDAMERICAN ENERGY HOLDINGS COMPANY

Offer to Exchange

Up to $1,700,000,000 in aggregate principal amount of registered 6.125% Senior Bonds due April 1, 2036 for

All outstanding unregistered 6.125% Senior Bonds due April 1, 2036

- We are offering to exchange new registered 6.125% senior bonds due April 1, 2036 for all of our outstanding unregistered 6.125% senior bonds due April 1, 2036.
- The exchange offer expires at 5:00 p.m., New York City time, on October 11, 2006, unless extended.
- The exchange offer is subject to customary conditions that may be waived by us.
- All initial 2006 bonds outstanding that are validly tendered and not validly withdrawn prior to the expiration of the exchange offer will be exchanged for the exchange 2006 bonds.
- Tenders of initial 2006 bonds may be withdrawn at any time before 5:00 p.m., New York City time, on the expiration date of the exchange offer.
- The exchange of initial 2006 bonds for exchange 2006 bonds will not be a taxable exchange for U.S. federal income tax purposes.
- We will not receive any proceeds from the exchange offer.
- The terms of the exchange 2006 bonds to be issued are substantially identical to the terms of the initial 2006 bonds, except that the exchange 2006 bonds will not have transfer restrictions, and you will not have registration rights.
- There is no established trading market for the exchange 2006 bonds, and we do not intend to apply for listing of the exchange 2006 bonds on any securities exchange or market quotation system.

See ‘‘Risk Factors’’ beginning on page 9 for a discussion of matters you should consider before you participate in the exchange offer.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

The date of this Prospectus is September 11, 2006

TABLE OF CONTENTS

In this prospectus, references to ‘‘we,’’ ‘‘our’’ and ‘‘us’’ are to MidAmerican Energy Holdings Company (or MEHC) and, except as the context otherwise requires, its consolidated subsidiaries and, as applicable, its equity investments.

In this prospectus, references to ‘‘initial 2006 bonds’’ are to the privately placed $1,700,000,000 aggregate principal amount of 6.125% Senior Bonds due 2036, references to ‘‘exchange 2006 bonds’’ are to the new 6.125% Senior Bonds due 2036, which will be registered under the Securities Act, and references to ‘‘bonds’’ are to, collectively, the initial 2006 bonds and the exchange 2006 bonds.

In this prospectus, references to ''U.S. dollars,'' ''dollars,'' ''$'' or ''cents'' are to the currency of the United States, references to pounds sterling ''£,'' ''sterling,'' ''pence'' or ''p'' are to the currency of Great Britain and references to ''pesos'' are to the currency of the Philippines. References to kW means kilowatts, MW means megawatts, GW means gigawatts, kWh means kilowatt hours, MWh means megawatt hours, GWh means gigawatt hours, kV means kilovolts, MMcf means million cubic feet, Bcf means billion cubic feet, and Dth means decatherms or one million British thermal units.

This prospectus incorporates important business and financial information about us that is not included or delivered with this prospectus. We will provide this information to you at no charge upon written or oral request directed to Douglas L. Anderson, General Counsel, MidAmerican Energy Holdings Company, 302 South 36th Street, Suite 400, Omaha, Nebraska 68131, (402) 341-4500. In order to ensure timely delivery of the information, any request should be made by October 2, 2006.

No dealer, salesperson or other individual has been authorized to give any information or to make any representations not contained in this prospectus in connection with the exchange offer. If given or made, such information or representations must not be relied upon as having been authorized by us. Neither the delivery of this prospectus nor any sale made hereunder shall, under any circumstances, create any implications that there has not been any change in the facts set forth in this prospectus or in our affairs since the date hereof.

Table of Contents

Each broker-dealer that receives exchange 2006 bonds for its own account pursuant to the exchange offer must acknowledge that it will deliver a prospectus in connection with any resale of such exchange 2006 bonds. The letter of transmittal accompanying this prospectus states that by so acknowledging and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an ''underwriter'' within the meaning of the Securities Act of 1933, as amended. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of the exchange 2006 bonds received in exchange for initial 2006 bonds where such initial 2006 bonds were acquired by such broker-dealer as a result of market-making activities or other trading activities. We have agreed that, for a period of 120 days after the expiration of the exchange offer, we will make this prospectus available to any broker-dealer for use in connection with any such resales. See ''Plan of Distribution.''

Table of Contents

NOTICE TO NEW HAMPSHIRE RESIDENTS

Table of Contents

SUMMARY

This section contains a general summary of certain of the information contained in this prospectus. It may not include all of the information that is important to you. You should read this entire prospectus, including the ''Risk Factors'' section and the financial statements and notes to those statements, before making an investment decision.

MIDAMERICAN ENERGY HOLDINGS COMPANY

Overview

We are a United States-based global energy company. We are a consolidated subsidiary of Berkshire Hathaway Inc. (or Berkshire Hathaway), which currently owns approximately 88.2% (86.6% on a diluted basis) of our outstanding common stock. The balance of our common stock is owned by a private investor group comprised of Walter Scott, Jr. (including family members and related entities), who is a member of our Board of Directors, David L. Sokol, our Chairman and Chief Executive Officer, and Gregory E. Abel, our President and Chief Operating Officer.

Our operations are organized and managed as eight distinct platforms: PacifiCorp, MidAmerican Funding, LLC (or MidAmerican Funding), which primarily includes MidAmerican Energy Company (or MidAmerican Energy), Northern Natural Gas Company (or Northern Natural Gas), Kern River Gas Transmission Company (or Kern River), CE Electric UK Funding Company (or CE Electric UK), which primarily includes Northern Electric Distribution Limited (or Northern Electric) and Yorkshire Electricity Distribution plc (or Yorkshire Electricity), CalEnergy Generation-Foreign, CalEnergy Generation-Domestic and HomeServices of America, Inc. (or HomeServices). Through these platforms, we own and operate an electric utility company in the western United States, a combined electric and natural gas utility company in the midwestern United States, two natural gas pipeline companies in the United States, two electricity distribution companies in Great Britain, a diversified portfolio of domestic and international independent power projects and the second-largest residential real estate brokerage firm in the United States.

Our energy subsidiaries generate, transmit, store, distribute and supply energy. As of June 30, 2006, our electric and natural gas utility subsidiaries serve approximately 6.1 million electricity customers and approximately 685,000 natural gas customers. Our natural gas pipeline subsidiaries operate interstate natural gas transmission systems with approximately 17,600 miles of pipeline in operation and a peak delivery capacity of 6.6 billion cubic feet of natural gas per day, which transported approximately 7.8% of the total natural gas consumed in the United States in 2005. As of June 30, 2006, we have interests in 15,601 net owned MW of power generation facilities in operation and under construction, including 14,158 net owned MW in facilities that are part of the regulated asset base of our electric utility businesses and 1,443 net owned MW in non-utility power generation facilities. Substantially all of our non-utility power generation facilities have long-term contracts for the sale of energy and/or capacity from the facilities.

On March 21, 2006, we acquired 100% of the common stock of PacifiCorp (the PacifiCorp Acquisition) from a wholly owned subsidiary of Scottish Power plc (or ScottishPower) for a cash purchase price of approximately $5.1 billion. PacifiCorp is a regulated electric utility company serving approximately 1.6 million residential, commercial and industrial customers in service territories in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. As of June 30, 2006, PacifiCorp owns, or has interests in, 69 thermal, hydroelectric and wind generating plants, with an aggregate facility net owned capacity of 8,469.9 MW.

Our principal executive offices are located at 666 Grand Avenue, Des Moines, Iowa 50309, and our telephone number is (515) 242-4300.

Table of Contents

THE EXCHANGE OFFER

On March 24, 2006, we privately placed $1,700,000,000 aggregate principal amount of 6.125% Senior Bonds due 2036, which we refer to as the initial 2006 bonds, in a transaction exempt from registration under the Securities Act of 1933, as amended, or the Securities Act. In connection with the private placement, we entered into a registration rights agreement, dated as of March 24, 2006, with the initial purchasers of the initial 2006 bonds. In the registration rights agreement, we agreed to offer our new 6.125% Senior Bonds due 2036, which will be registered under the Securities Act, and which we refer to as the exchange 2006 bonds, in exchange for the initial 2006 bonds. The exchange offer described in this prospectus is intended to satisfy our obligations under the registration rights agreement. We also agreed to deliver this prospectus to the holders of the initial 2006 bonds. In this prospectus, we refer to the initial 2006 bonds and the exchange 2006 bonds collectively as the bonds. You should read the discussion under the headings ‘‘Summary — Terms of the Bonds’’ and ‘‘Description of Bonds’’ for information regarding the bonds.

The Exchange Offer

This is an offer to exchange $1,000 in principal amount of the exchange 2006 bonds for each $1,000 in principal amount of the initial 2006 bonds. The exchange 2006 bonds are substantially identical to the initial 2006 bonds, except that the exchange 2006 bonds will generally be freely transferable. We believe that you can transfer the exchange 2006 bonds without complying with the registration and prospectus delivery provisions of the Securities Act if you:

- acquire the exchange 2006 bonds in the ordinary course of your business;
- are not and do not intend to become engaged in a distribution of the exchange 2006 bonds;
- are not an ‘‘affiliate’’ (within the meaning of the Securities Act) of ours;
- are not a broker-dealer (within the meaning of the Securities Act) that acquired the initial 2006 bonds from us or our affiliates; and
- are not a broker-dealer (within the meaning of the Securities Act) that acquired the initial 2006 bonds in a transaction as part of its market-making or other trading activities.

If any of these conditions are not satisfied and you transfer any exchange 2006 bonds without delivering a proper prospectus or without qualifying for a registration exemption, you may incur liability under the Securities Act. See ‘‘The Exchange Offer — Terms of the Exchange.’’

Registration Rights Agreement

We have agreed to file an exchange offer registration statement or, under certain circumstances, a shelf registration statement pursuant to a registration rights agreement with respect to the bonds. If we fail to comply with certain of our obligations under the registration rights agreement, we will pay additional interest in cash on the bonds for so long as such failure continues. See

Table of Contents

''Description of the Bonds — Exchange Offer; Registration Rights.''

Minimum Condition	The exchange offer is not conditioned on any minimum aggregate principal amount of initial 2006 bonds being tendered for exchange.
Expiration Date	The exchange offer will expire at 5:00 p.m., New York City time, on October 11, 2006, unless we extend it.
Exchange Date	The initial 2006 bonds will be accepted for exchange at the time when all conditions of the exchange offer are satisfied or waived. The exchange 2006 bonds will be delivered promptly after we accept the initial 2006 bonds.
Conditions to the Exchange	Our obligation to complete the exchange offer is subject to certain conditions. See ''The Exchange Offer — Conditions to the Exchange Offer.'' We reserve the right to terminate or amend the exchange offer at any time prior to the expiration date upon the occurrence of certain specified events.
Withdrawal Rights	You may withdraw the tender of your initial 2006 bonds at any time before the expiration of the exchange offer on the expiration date. Any initial 2006 bonds not accepted for any reason will be returned to you without expense as promptly as practicable after the expiration or termination of the exchange offer.
Procedures for Tendering Original Bonds	See ''The Exchange Offer — How to Tender.''
United States Federal Income Tax Consequences	The exchange of the initial 2006 bonds for the exchange 2006 bonds will not be a taxable exchange for U.S. federal income tax purposes, and holders will not recognize any taxable gain or loss as a result of such exchange.
Effect on Holders of Initial 2006 Bonds	If the exchange offer is completed on the terms and within the period contemplated by this prospectus, holders of the initial 2006 bonds will have no further registration or other rights under the registration rights agreement, except under limited circumstances. See ''The Exchange Offer — Other.'' **Holders of initial 2006 bonds who do not tender their initial 2006 bonds will continue to hold those initial 2006 bonds. All untendered, and tendered but unaccepted, initial 2006 bonds will continue to be subject to the transfer restrictions provided for in the initial 2006 bonds and the indenture under which the initial 2006 bonds have**

Table of Contents

been issued. To the extent that the initial 2006 bonds are tendered and accepted in the exchange offer, the trading market, if any, for the initial 2006 bonds could be adversely affected. See ''Risk Factors — Risks Associated with the Exchange Offer — You may not be able to sell your initial 2006 bonds if you do not exchange them for registered exchange 2006 bonds in the exchange offer.''; ''— Your ability to sell your initial 2006 bonds may be significantly more limited and the price at which you may be able to sell your initial 2006 bonds may be significantly lower if you do not exchange them for registered exchange 2006 bonds in the exchange offer.''; and ''The Exchange Offer — Other.''

Use of Proceeds	We will not receive any proceeds from the issuance of exchange 2006 bonds in the exchange offer.
Exchange Agent	The Bank of New York Trust Company, N.A., is serving as the exchange agent in connection with the exchange offer.

TERMS OF THE BONDS

General	$1,700,000,000 aggregate principal amount of 6.125% Senior Bonds due 2036. The initial 2006 bonds were, and the exchange 2006 bonds will be, issued under a fourth supplement to the indenture, dated as of October 4, 2002, as amended as of March 24, 2006, between us and The Bank of New York Trust Company, N.A., as trustee. On October 4, 2002, we issued $200,000,000 of our 4.625% Senior Notes due 2007 (which we refer to as the series A notes) and $500,000,000 of our 5.875% Senior Notes due 2012 (which we refer to as the series B notes), on May 16, 2003, we issued $450,000,000 of our 3.50% Senior Notes due 2008 (which we refer to as the series C notes), and on February 12, 2004 we issued $250,000,000 of our 5.00% Senior Notes due 2014 (which we refer to as the series D notes), in each case pursuant to the indenture. Unless otherwise indicated, references to the securities in this prospectus include the series A notes, the series B notes, the series C notes, the series D notes and the bonds (and any other series of notes, bonds or other securities hereafter issued under a supplemental indenture or otherwise pursuant to the indenture).
Maturity Date	April 1, 2036.
Interest Payment Dates	April 1 and October 1, commencing October 1, 2006.
Optional Redemption	We may redeem the bonds, at our option, in whole or in part, at any time, at a redemption price equal to the greater of: (1) 100% of the principal amount of the 2006 bonds to be redeemed; or (2) the sum of the present values of the remaining scheduled payments of principal of and interest on the bonds to be redeemed discounted to the date of redemption on a semiannual basis (assuming a 360-day year consisting of twelve 30-day months) at a discount rate equal to the yield on equivalent Treasury securities plus 25 basis points, plus, for (1) or (2) above, whichever is applicable, accrued and unpaid interest, if any, on such bonds to the date of redemption. See ''Description of the Bonds-Optional Redemption.''
Sinking Fund	The bonds will not be subject to a mandatory sinking fund.
Ranking	The bonds will be our general, unsecured senior obligations and will rank *pari passu* in right of payment with all our other existing and future senior unsecured obligations (including the series A notes, series B notes, series C notes and series D notes) and senior in right of payment to all our existing and future subordinated obligations. The bonds will be effectively subordinated to all our existing and future secured obligations and to all existing and future obligations of our subsidiaries.
Change of Control	Upon the occurrence of a Change of Control, each holder of the bonds will have the right, at the holder's option, to require us to repurchase all or any part of the holder's bonds at a purchase price in cash equal to 101% of the principal thereof, plus accrued and unpaid interest, if any, to the date of such purchase in accordance with the procedures set forth in the indenture. See ''Description of the Bonds — Covenants — Purchase of Securities Upon a Change of Control.''
Covenants	The indenture contains covenants that, among other things, restrict our ability to grant liens on our assets and our ability to merge, consolidate or transfer or lease all or substantially all of our assets. See ''Description of the Bonds — Covenants.''
Events of Default	Events of default with respect to the securities of any series, including the bonds, are defined in the indenture as being any one of the following events:

(1) default as to the payment of principal of, or premium, if any, on any security of that series or as to any payment required in connection with a Change of Control;

(2) default as to the payment of interest on any security of that series for 30 days after payment is due;

(3) failure to make a Change of Control Offer required under the covenants described under ''Purchase of Securities Upon a Change of Control'' above or a failure to purchase the securities of that series tendered in respect of such Change of Control Offer;

(4) our failure to perform, or breach by us of, any covenant, agreement or warranty contained in the indenture or the securities of that series, which failure continues for 30 days after written notice thereof is provided to us pursuant to the indenture and the trustee by the holders of at least a majority in aggregate principal amount outstanding of the securities of that series, as provided in the indenture;

(5) default by us or any significant subsidiary (as defined later in this prospectus) on any other debt (other than debt that is non-recourse to us) if either (x) such default results from failure to pay principal of such debt in excess of $100 million when due after any applicable grace period or (y) as a result of such default, the maturity of such debt has been accelerated prior to its scheduled maturity and such default has not been cured within the applicable grace period, and such acceleration has not been rescinded, and the principal amount of such debt, together with the principal amount of any other of our debt and that of our significant subsidiaries (not including debt that is non-recourse to us) that is in default as to principal, or the maturity of which has been accelerated, aggregates $100 million or more;

(6) the entry by a court of one or more judgments against us or any of our significant subsidiaries (other than a judgment that is non-recourse to us) requiring payment by us in an aggregate amount in excess of $100,000,000 (excluding (i) the amount thereof covered by insurance or by a bond written by a person other than one of our affiliates (other than in respect of the series C or D notes and the bonds, Berkshire Hathaway or any of its affiliates that provide commercial insurance in the ordinary course of their business) and (ii) judgments that are non-recourse to us), which judgments or orders has not been vacated, discharged, satisfied or stayed pending appeal within 60 days from entry; or

(7) certain events involving bankruptcy, insolvency or reorganization with respect to us or any of our significant subsidiaries.

See ''Description of the Bonds — Definitions'' and ''— Events of Default.''

Ratings

The bonds have initially been assigned ratings of Baa1 by Moody's, BBB+ by S&P and BBB+ by Fitch. However, these ratings are subject to change at any time.

Denomination and Form

The initial 2006 bonds were, and the exchange 2006 bonds will be, issued in denominations of $2,000 and any integral multiple of $1,000. The initial 2006 bonds were, and the exchange bonds will be, represented by one or more global securities registered in the name of The Depository Trust Company, or DTC, or its nominee. Beneficial interests in the global securities representing the initial 2006 bonds are, and beneficial interests in the global securities representing the exchange 2006 bonds will be, shown on, and transfers of the beneficial interests in the global securities representing the initial 2006 bonds are, and transfers of the beneficial interests in the global securities representing the exchange 2006 bonds will be, effected only through, records maintained by DTC and its participants. Except as described later in this prospectus, the bonds in certificated form will not be issued. See ''Description of the Bonds — Global Bonds; Book-Entry System.''

Trustee	The Bank of New York Trust Company, N.A. is the trustee for the holders of the bonds.
Governing Law	The bonds, the indenture and the other documents for the offering of the bonds are governed by the laws of the State of New York.

Risk Factors

This investment involves risks. Before you invest in the bonds, you should carefully consider the matters set forth under the heading ''Risk Factors'' and all other information in this prospectus.

RISK FACTORS

An investment in the bonds is subject to numerous risks, including, but not limited to, those set forth below. In addition to the information contained elsewhere in this prospectus, you should carefully consider the following risk factors when evaluating an investment in the bonds.

Risks Associated with Our Corporate and Financial Structure

We are a holding company that depends on distributions from our subsidiaries and joint ventures to meet our needs.

We are a holding company and derive substantially all of our income and cash flow from our subsidiaries and joint ventures. We expect that future development and acquisition efforts will be similarly structured to involve operating subsidiaries and joint ventures. We are dependent on the earnings and cash flows of, and dividends, loans, advances or other distributions from, our subsidiaries and joint ventures to generate the funds necessary to meet our obligations, including the payment of the principal amount of, and/or any interest or premiums on, the bonds. All required payments on debt and preferred stock at subsidiary levels will be made before funds from subsidiaries are available to us. The availability of distributions from such entities is also subject to:

- their earnings and capital requirements;
- the satisfaction of various covenants and conditions contained in financing documents by which they are bound or in their organizational documents; and
- in the case of our regulated utility subsidiaries, regulatory restrictions which restrict their ability to distribute profits to us.

Our subsidiaries and joint ventures are separate and distinct legal entities and have no obligation, contingent or otherwise, to pay any amounts due pursuant to the bonds or to make any funds available, whether by dividends, loans or other payments, for payment of the bonds, and do not guarantee the payment of the bonds.

We are substantially leveraged, the terms of the bonds do not restrict our ability or our subsidiaries' ability to incur additional indebtedness which could have an adverse impact on our financial condition and the bonds are structurally subordinated to the indebtedness of our subsidiaries.

Our substantial leverage level presents the risk that we might not generate sufficient cash to service our indebtedness, including the indebtedness under the bonds, or that our leveraged capital structure could limit our ability to finance future acquisitions, develop additional projects, compete effectively and operate successfully under adverse economic conditions. At June 30, 2006, our outstanding senior indebtedness was $4.5 billion and our outstanding subordinated indebtedness, which consists of our trust preferred securities, was $1.5 billion. These amounts exclude our guarantees and letters of credit in respect of subsidiary and equity investment indebtedness aggregating $112.5 million as of June 30, 2006. We expect to incur additional indebtedness in the future.

Our subsidiaries also have significant amounts of indebtedness. At June 30, 2006, our consolidated subsidiaries had outstanding indebtedness totaling $11.4 billion. This amount does not include (i) any trade debt or preferred stock obligations of our subsidiaries, (ii) our subsidiaries' letters of credit in respect of their indebtedness or (iii) our share of the outstanding indebtedness of our and our subsidiaries' equity investments.

The terms of the bonds do not limit our ability or the ability of our subsidiaries or joint ventures to incur additional debt or issue additional preferred stock. Accordingly, we or our subsidiaries or joint ventures could enter into acquisitions, 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 have a material adverse effect on our or our subsidiaries' operating results. A highly leveraged capital structure could also impair our or our subsidiaries' overall credit quality, making it more difficult for us to finance our operations or issue future indebtedness on favorable terms, and could result in a downgrade in the ratings of our indebtedness, including the indebtedness under the bonds, by credit rating agencies. Further, if any of our or our subsidiaries' indebtedness is accelerated due to an event of default under such indebtedness and such acceleration results in an event of default under some or all of our other indebtedness or under the indenture for the bonds, we may not have sufficient funds to repay all of the accelerated indebtedness, including the indebtedness under the bonds.

Claims of creditors of our subsidiaries and joint ventures have priority over your claims as a holder of the bonds with respect to the assets and earnings of our subsidiaries and joint ventures. In addition, the stock or assets of substantially all of our operating subsidiaries and joint ventures is directly or indirectly pledged to secure their financings and, therefore, may be unavailable as potential sources of repayment of the bonds.

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

We are a majority owned subsidiary of Berkshire Hathaway and, therefore, Berkshire Hathaway has control over the decision of all matters submitted for shareholder approval, including the election of our directors who oversee our management and affairs. 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.

Risks Associated with Our Business

Our growth has been achieved, in significant part, through strategic acquisitions, and additional acquisitions may not be successful.

Our growth has been achieved, in significant part, through strategic acquisitions. We intend to continue to pursue selected opportunities for acquisitions of assets and businesses, as well as business combinations, within our industries for the foreseeable future. We investigate opportunities that we believe may increase shareholder value and build on existing businesses. We have participated in the past, and our security holders may assume that at any time we may be participating, in bidding or other negotiations for such transactions. This participation may or may not result in a transaction for us. Any transaction that does take place may involve consideration in the form of cash, debt or equity securities.

Since 1996, we have completed several significant acquisitions, including the acquisitions of Northern Electric, Yorkshire Electricity, MidAmerican Energy, Kern River, Northern Natural Gas and, most recently, PacifiCorp.

The successful integration of any businesses we may acquire in the future will entail numerous risks, including, among others, the risk of diverting management's attention from day-to-day operations, the risk that the acquired businesses will require substantial capital and financial investments and the risk that the investments will fail to perform in accordance with expectations. Any substantial diversion of management attention and any substantial difficulties encountered in the transition and integration process could have a material adverse effect on our operating revenue, levels of expenses and operating results.

In addition, it has been publicly reported over the past several years that many of the participants in the United States energy industry, including the prior owners of Kern River and Northern Natural Gas and potentially including other industry participants from whom we may choose to purchase additional businesses in the future, have had or may have liquidity, creditworthiness and other financial difficulties. As a consequence, there can be no assurance that any such sellers will not enter into bankruptcy or insolvency proceedings or that they will otherwise be able, required or willing to perform on their indemnification obligations to us if we should elect to pursue any such claims we may have against any of them under our acquisition agreements in the future. If our due diligence efforts were or are unsuccessful in identifying and analyzing all material liabilities relating to acquired companies and if there were to be any material undisclosed liabilities, or if there were to be other unexpected consequences from any such bankruptcy or insolvency proceeding, such as a successful

challenge as to whether the prices paid by us constituted reasonably equivalent value within the meaning of the relevant bankruptcy laws, then any such bankruptcy or insolvency, or failure by any of these sellers to perform their indemnification obligations to us, could have a material adverse effect on our business, financial condition, results of operations and the market prices and rates for our securities.

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

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

Through our energy subsidiaries, we are continuing to develop, construct, own and operate new or expanded facilities and we presently expect that our energy subsidiaries will make substantial annual capital expenditures relating to new or expanded facilities over the next several years. PacifiCorp is engaged in several large construction or expansion projects, including construction of new generating facilities and various capital projects related to transmission and distribution. In addition, in connection with the acquisition of PacifiCorp, we have committed to cause PacifiCorp to undertake several other capital expenditure projects, principally relating to environmental controls, transmission and distribution and other facilities. PacifiCorp expects to incur significant construction, expansion and other capital expenditure costs over the next several years. MidAmerican Energy is also engaged in constructing new electric generating projects in Iowa. Our subsidiaries depend upon both internal and external sources of liquidity to provide working capital and to fund capital requirements. If we do not elect to provide any needed funding to any of our subsidiaries, they may be unable to fund needed capital requirements and may need to postpone or cancel planned capital expenditures.

In the future, we expect to pursue the development, construction, ownership and operation of additional new or expanded energy projects (including, without limitation, generation, distribution, transmission, storage and supply projects and related activities, exploration and production, infrastructure and services), both domestically and internationally. The completion of any or all of these pending, proposed or future projects is subject to substantial risk and may expose us to significant costs. We cannot assure you that our development or construction efforts on any particular project, or our efforts generally, will be successful. If we are unable to complete the development or construction of any such project, or if we decide to delay or cancel a project, we may not be able to recover our investment in that project.

Also, a proposed expansion or new project may cost more than planned to complete, and such excess costs, if related to a regulated asset and found to be imprudent, may not be recoverable in rates. The inability to successfully and timely complete a project or avoid unexpected costs may require us to perform under guarantees, and the inability to avoid unsuccessful projects or to recover any excess costs may materially affect our ability to service our obligations under the bonds.

Our subsidiaries are subject to certain operating uncertainties which may adversely affect our financial position, results of operation and ability to service the bonds.

The operation of complex electric and gas utility (including transmission and distribution) systems, pipelines or power generating facilities which are spread over large geographic areas involves many risks associated with operating uncertainties and events beyond our control. These risks include the breakdown or failure of power generation equipment, compressors, pipelines, transmission and distribution lines or other equipment or processes, unscheduled plant outages, work stoppages, transmission and distribution system constraints or outages, fuel shortages or interruptions, low water flows, performance below expected levels of output, capacity or efficiency, operator error and catastrophic events such as severe storms, fires, earthquakes or explosions. A casualty occurrence might result in injury or loss of life, extensive property damage or environmental damage. The realization of any of these risks could significantly reduce or eliminate our affiliates’ operating revenue

Table of Contents

or significantly increase our affiliates’ expenses, thereby adversely affecting the ability to receive distributions from subsidiaries and joint ventures. For example, if our affiliates cannot operate their electric or natural gas facilities at full capacity due to restrictions imposed by environmental regulations, their operating revenue could decrease due to decreased wholesale sales and their expenses could increase due to the need to obtain energy from higher cost sources. Any reduction of operating revenue for such reason, or any other reduction of our affiliates’ operating revenue or increase in their expenses resulting from the risks described above, could decrease our net cash flow and provide us with fewer funds with which to service the bonds.

Further, we cannot assure you that our current and future insurance coverage will be sufficient to replace lost operating revenue or cover repair and replacement costs, especially in light of the recent catastrophic events in the insurance markets that make it more difficult or costly to obtain certain types of insurance.

Acts of sabotage and terrorism aimed at our facilities, the facilities of our fuel suppliers or customers, or at regional transmission facilities could adversely affect our business.

Since the September 11, 2001 terrorist attacks, the United States government has issued warnings that energy assets, specifically our nation’s pipeline and electric utility infrastructure, may be the future targets of terrorist organizations. These developments have subjected our operations to increased risks. Damage to the assets of our fuel suppliers, the assets of our customers or our own assets or at regional transmission facilities inflicted by terrorist groups or saboteurs could result in a significant decrease in operating revenue and significant repair costs, force us to increase security measures, cause changes in the insurance markets and cause disruptions of fuel supplies, energy consumption and markets, particularly with respect to natural gas and electric energy. Any of these consequences of acts of terrorism could materially affect our results of operations and decrease the amount of funds we have available to make payments on the bonds. Instability in the financial markets as a result of terrorism or war could also materially adversely affect our ability to raise capital.

We are subject to energy regulation, legislation and political risks and changes in regulations and rates or legislative developments may adversely affect our business, financial condition, results of operations and ability to service the bonds.

We are subject to comprehensive governmental regulation, including regulation in the United States by various federal, state and local regulatory agencies, regulation in the United Kingdom and regulation in the Philippines, all of which significantly influences our operating environment, the price we are allowed to charge our customers, our capital structure, our costs and our ability to recover our costs from customers. These regulatory agencies include, among others, the Federal Energy Regulatory Commission (or FERC), the Environmental Protection Agency (or EPA), the Nuclear Regulatory Commission (or NRC), the United States Department of Transportation (or DOT), the Iowa Utilities Board (or IUB), the Utah Public Service Commission (or UPSC), the Oregon Public Utility Commission (or OPUC), the Wyoming Public Service Commission (or WPSC), the Washington Utilities and Transportation Commission (or WUTC), the Idaho Public Utilities Commission (or IPUC), the California Public Utilities Commission (or CPUC), the Illinois Commerce Commission (or ICC), the South Dakota Public Utilities Commission (or SPDUC), other state utility boards, numerous local agencies, the Gas and Electricity Markets Authority (or GEMA), which in discharging certain of its powers acts through its staff within the Office of Gas and Electricity Markets in the United Kingdom (or Ofgem), and various other governmental agencies in the United States, the United Kingdom and the Philippines.

We also conduct our businesses in conformance with a multitude of federal, state and foreign laws, which are subject to significant changes at any time. Changes in regulations or the imposition of additional regulations by any of these entities or new legislation could have a material adverse impact on our results of operations. For example, such changes could result in increased retail competition in PacifiCorp's or MidAmerican Energy's service territory, changes to the hydroelectric relicensing process under the Federal Power Act, encouragement of investments in renewable or lower-emission generation, the acquisition by a municipality or other quasi-governmental body of our distribution

Table of Contents

facilities (by negotiation, legislation or condemnation or by a vote in favor of a Public Utility District under Oregon law) or a negative impact on our current transportation and cost recovery arrangements. As another example, we could be adversely affected by Senate Bill 408, which was enacted in September 2005 in the State of Oregon, where PacifiCorp is headquartered. That legislation resulted in a reduction by OPUC in the rates that PacifiCorp would have been permitted to charge to its Oregon customers, and in the future may limit the ability of PacifiCorp and other public utilities to recover future federal and state income tax expenses in Oregon retail rates. Unless the relevant provisions of Senate Bill 408 are amended, modified or repealed in a manner satisfactory to us, such legislation could have a material adverse effect upon PacifiCorp's results of operations and cash flows, especially if other states in PacifiCorp's territory enact similar legislation or rules. Similar legislation or rules could also be enacted in other states where we currently provide utility services.

Several of PacifiCorp's hydroelectric projects are in some stage of the FERC relicensing process under the Federal Power Act, as several of PacifiCorp's long-term operating licenses have expired or will expire in the next few years. The relicensing process is a political and public regulatory process that involves sensitive resource issues and uncertainties. We cannot predict with certainty the requirements (financial, operational or otherwise) that may be imposed during the relicensing process, the economic impact of those requirements, whether new licenses will ultimately be issued or whether PacifiCorp will be willing to meet the relicensing requirements to continue operating its hydroelectric projects.

Kern River's transportation operations are subject to a FERC regulated tariff that is designed to allow it an opportunity to recover its costs together with a regulated return on equity. In April 2004, Kern River filed a rate case with the FERC seeking an increase in its FERC regulated tariff. On March 2, 2006, Kern River received an initial decision on the case from the administrative law judge which, among other things, proposed an authorized rate of return of 9.34%. Kern River is currently authorized to collect an authorized rate of return of 13.25%. The administrative law judge's initial decision is nonbinding and after briefing, the FERC will issue its initial decision on the case. The initial FERC decision, which will become binding and may result in rate refunds, is not expected until late 2006 or early 2007. Kern River believes that it has a strong basis for obtaining a final FERC decision with a higher return on equity component in its regulated rates. However, we cannot predict with certainty whether the final decision will include a higher return on equity or, if higher, how much higher.

On August 8, 2005, the Energy Policy Act of 2005 (or the Energy Policy Act) was signed into law. That law potentially impacts many segments of the energy industry. As a result of the law, the FERC has and will continue to issue new regulations and regulatory decisions in areas such as electric system reliability, electric transmission expansion and pricing, regulation of utility holding companies, and enforcement authority. The full impact of those decisions remains uncertain.

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. The implementation of such measures could result in the imposition of more comprehensive or stringent requirements on us or our subsidiaries or other industry participants, which would result in increased compliance costs and could have a material adverse effect on our business, financial condition, results of operations and ability to service the bonds.

Recovery of costs by our energy subsidiaries is subject to regulatory review and approval, and the inability to recover costs may adversely affect their operating revenue and cash flows.

PacifiCorp and MidAmerican Energy are subject to the jurisdiction of federal and state regulatory authorities. The FERC establishes tariffs under which these utilities provide transmission service to the wholesale market and the retail market (in states allowing retail competition). The FERC also establishes both cost-based and market-based tariffs under which these utilities sell electricity at wholesale and has licensing authority over most of PacifiCorp's hydroelectric generation facilities. In

Table of Contents

addition, the utility regulatory commissions in each state served by these utilities independently determine the rates that these utilities may charge their respective retail customers in those states.

Each state's rate-setting process is based upon the state utility commission's acceptance of an allocated share of total utility costs for purposes of setting that state's retail rates. When different states adopt different methods to address this interjurisdictional cost allocation issue, some costs may not be incorporated into rates in any state. Rate-making is also generally done on the basis of estimates of normalized costs, so if in a specific year realized costs are higher than normal, rates will not be sufficient to cover those costs. Each state utility commission generally sets rates based on a test year established according to that commission's policies. However, in Iowa, MidAmerican Energy has agreed not to seek a general increase in electric base rates to become effective prior to January 1, 2013 unless its Iowa jurisdictional electric return on equity for any year falls below 10%. Certain states use a future test year or allow for escalation of historical costs. In the states in which PacifiCorp operates that use a historical test year, rate adjustments could lag cost increases, or decreases, by up to two years. This regulatory lag causes the utilities to incur costs, including significant new investments, for which recovery through rates is delayed. In addition, each state commission decides what percentage return a utility will be permitted to earn on its equity investment. They also decide what level of expense and investment is necessary, reasonable and prudent in providing service and may disallow and deny recovery in rates for any costs that do not meet this standard. For these reasons, as well as others (such as recently enacted legislation and the outcome of the recent rate case in Oregon limiting or denying the ability of a utility to recover taxes in rates or a recent WUTC decision suggesting that in order to include the cost of generation in retail rates, a utility must demonstrate that the generation provides benefits to each state the utility serves), the rates authorized by the state regulators may not be sufficient to cover costs incurred to provide electrical services in any given period.

Kern River and Northern Natural Gas are subject to regulation by various federal and state agencies. As owners of interstate natural gas pipelines, Northern Natural Gas' and Kern River's rates, services and operations are subject to regulation by the FERC. The FERC administers, among other things, the Natural Gas Act and the Natural Gas Policy Act of 1978. The FERC has jurisdiction over, among other things, 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. The FERC also has jurisdiction over the rates and charges and terms and conditions of service for the transportation of natural gas in interstate commerce. Additional proposals and proceedings that might affect the interstate natural gas pipeline industry are considered from time to time by Congress, the FERC, state regulatory bodies and the courts. For these reasons, as well as others, the rates authorized by the FERC may not be sufficient to cover costs incurred to provide services in any given period.

We are subject to environmental, health, safety and other laws and regulations which may adversely impact us.

Through our subsidiaries and joint ventures, we are subject to a number of environmental, health, safety and other laws and regulations affecting many aspects of our present and future operations, both domestic and foreign, including air emissions, water quality, endangered species, wastewater discharges, solid wastes, hazardous substances and safety matters. We may incur substantial costs and liabilities in connection with our operations as a result of these laws and regulations. In particular, the cost of future compliance with federal, state and local clean air laws, such as those that relate to addressing regional haze issues and those that require certain generators, including some of our subsidiaries' electric generating facilities, to limit emissions of nitrogen oxide (or NO_x), sulfur dioxide (or SO_2), carbon dioxide, mercury and other potential pollutants or emissions, may require us to make significant capital expenditures which may not be recoverable through future rates. In addition, these costs and liabilities may include those relating to claims for damages to property and persons resulting from our operations. Regulatory changes, including new interpretations of existing laws and regulations, imposing more comprehensive or stringent requirements on us, to the extent such changes

Table of Contents

would result in increased compliance costs or additional operating restrictions, could have a material adverse effect on our business, financial condition, results of operations and ability to service the bonds.

In addition, regulatory compliance for existing facilities and the construction of new facilities is a costly and time-consuming process, and intricate and rapidly changing environmental regulations may require major expenditures for permitting and create the risk of expensive delays or material impairment of value if projects cannot function as planned due to changing regulatory requirements or local opposition.

The Pipeline Safety Improvement Act of 2002 (or PSIA) and its implementing rules that became effective on February 14, 2004, require interstate pipeline operators to develop comprehensive integrity management programs, take measures to protect pipeline segments located in ''high consequence areas'' and provide ongoing mitigation and monitoring. We believe our pipeline operations currently comply in all material respects with PSIA and related rules. However, in the future, we may incur unexpected capital costs and/or operating costs in order to maintain compliance. Moreover, regulatory agencies and the public continue to focus on pipeline safety issues which may result in additional inspection, monitoring, testing, reporting and other requirements being implemented in the future that could increase our operating costs and/or capital costs. Our FERC-approved tariffs or competition from other energy sources may not allow us to recover these increased costs of compliance.

In addition to operational standards, environmental laws also impose obligations to clean up or remediate contaminated properties or to pay for the cost of such remediation, often upon parties that did not actually cause the contamination. Accordingly, we may become liable, either contractually or by operation of law, for remediation costs even if the contaminated property is not presently owned or operated by us, or if the contamination was caused by third parties during or prior to our ownership or operation of the property. Given the nature of the past industrial operations conducted by us and others at our properties, there can be no assurance that all potential instances of soil or groundwater contamination have been identified, even for those properties where an environmental site assessment or other investigation has been conducted. Although we have accrued reserves for our known remediation liabilities, 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 which may be material. Any failure to recover increased environmental, health or safety costs incurred by us may have a material adverse effect on our business, financial condition, results of operations and ability to service the bonds.

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

Regulatory requirements applicable in the future to nuclear generating facilities could adversely affect our results of operations and, in particular, MidAmerican Energy. We are subject to certain generic risks associated with utility nuclear generation, which include the following:

- the potential harmful effects on the environment and human health resulting from the operation of nuclear facilities and the storage, handling and disposal of high-level and low-level radioactive materials;

- limitations on the amounts and types of insurance commercially available in respect of losses that might arise in connection with nuclear operations; and

- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generating facilities. In the event of noncompliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC have, in the past, necessitated substantial capital expenditures at nuclear plants, including the facility in which MidAmerican Energy has a 25% ownership interest, and additional expenditures

could be required in the future. In addition, although we have no reason to anticipate a serious nuclear incident at the facility in which MidAmerican Energy has an interest, if an incident did occur, it could have a material but presently undeterminable adverse effect on our financial position, results of operations and ability to service the bonds.

Increased competition resulting from legislative, regulatory and restructuring efforts could have a significant financial impact on our and our energy subsidiaries and consequently decrease our operating revenue.

The wholesale generation segment of the electric industry has been and will continue to be significantly impacted by competition. Competition in the wholesale market has resulted in a proliferation of power marketers and a substantial increase in market activity. Many of these marketers have experienced financial difficulties and the market continues to be volatile. Profits from wholesale electric transactions have a material impact on our results of operations. Accordingly, significant changes in the wholesale electric markets could have a material adverse effect on our utility subsidiaries' financial position, results of operations and the ability to service the bonds.

As a result of FERC orders, including Order 636, the FERC's policies favoring competition in natural gas markets, the expansion of existing pipelines and the construction of new pipelines, the interstate pipeline industry has experienced some failure to renew, or turn back, of firm capacity, as existing transportation service agreements expire and are terminated. Local distribution companies (or LDCs), and end-use customers have more choices in the new, more competitive environment and may be able to obtain service from more than one pipeline to fulfill their natural gas delivery requirements. If a pipeline experiences capacity turn back and is unable to remarket the capacity, the pipeline or its remaining customers may have to bear the costs associated with the capacity that is turned back. Any new pipelines that are constructed could compete with our pipeline subsidiaries for customers' service needs. Increased competition could reduce the volumes of gas transported by our pipeline subsidiaries or, in cases where they do not have long-term fixed rate contracts, could force our pipeline subsidiaries to lower their rates to meet competition. This could adversely affect our pipeline subsidiaries' financial results.

A significant decrease in demand for natural gas in the markets served by our subsidiaries' pipeline and distribution systems would significantly decrease our operating revenue and thereby adversely affect our business, financial condition, results of operations and ability to service the bonds.

A sustained decrease in demand for natural gas in the markets served by our subsidiaries' pipeline and distribution systems would significantly reduce our operating revenue and adversely affect our ability to service the bonds. Factors that could lead to a decrease in market demand include:

- a recession or other adverse economic condition that results in a lower level of economic activity or reduced spending by consumers on natural gas;

- an increase in the market price of natural gas or a decrease in the price of other competing forms of energy, including electricity, coal and fuel oil;

- higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of natural gas or that limit the use of natural gas;

- a shift by consumers to more fuel-efficient or alternative fuel machinery or an improvement in fuel economy, whether as a result of technological advances by manufacturers, legislation proposing to mandate higher fuel economy, or otherwise; and

- a shift by our pipeline and distribution customers to the use of alternate fuels, such as fuel oil, due to price differentials or other incentives.

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 which

are beyond HomeServices' control. Any of the following 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 operating revenue and profitability:

- rising interest rates or unemployment rates;

- periods of economic slowdown or recession in the markets served;

- decreasing home affordability;

- declining demand for residential real estate as an investment; and

- nontraditional sources of new competition.

Failure of our significant power purchasers, pipeline customers and British retail suppliers to pay amounts due under their contracts or other commitments could reduce our operating revenue materially and adversely affect our ability to refinance the bonds prior to maturity.

Our subsidiaries' non-utility generating facilities and both of our pipeline subsidiaries are dependent upon a relatively small number of customers for a significant portion of their operating revenue. In addition, our utility distribution businesses in the United Kingdom are dependent upon a relatively small number of retail suppliers, including one retail supplier who represented approximately 44% of the total operating revenue in 2005 of our utility distribution businesses in the United Kingdom. PacifiCorp and MidAmerican Energy also rely on their wholesale customers to fulfill their commitments and pay for energy delivered to them on a timely basis. As a result, our profitability and ability to make payments under the bonds will depend in part upon the continued financial performance and creditworthiness of these customers. Accordingly, failure of one or more of our most significant customers to pay for contracted electric generating capacity, pipeline capacity reservation charges or distribution system use charges, as applicable, for reasons related to financial distress or otherwise, could reduce our operating revenue materially if we are not able to make adequate alternate arrangements on a timely basis, such as adequate replacement contracts. The replacement of any of our existing long-term contracts or British retail suppliers, should it become necessary, will depend on a number of factors beyond our control, including:

- the availability of economically deliverable natural gas for transport through our pipeline system, including in particular continued availability of adequate supplies from the Rocky Mountains, Hugoton, Permian, Anadarko and Western Canadian supply basins currently accessible to our pipeline subsidiaries;
- existing competition to deliver natural gas to the upper Midwest and southern California;
- new pipelines or expansions potentially serving the same markets as our pipelines;
- the growth in demand for natural gas in the upper Midwest, southern California, Nevada and Utah;
- whether transportation of natural gas pursuant to long-term contracts continues to be market practice;
- the actions of regulators, including the electricity regulator in the United Kingdom;
- the availability and financial condition of replacement British retail suppliers; and
- whether our business strategy, including our expansion strategy, continues to be successful.

Any failure to replace a significant portion of these contracts on adequate terms or to make other adequate alternate arrangements, should it become necessary, may have a material adverse effect on our business, financial condition, results of operations and ability to service the bonds.

Our energy businesses are subject to power and fuel price fluctuations, weather risks, commodity price risks and credit risks that could adversely affect our results of operations and our ability to refinance the bonds or other senior debt.

We are exposed to commodity price risks, energy transmission price risks and credit risks in our subsidiaries' generation, retail distribution and pipeline operations. Specifically, such possible risks

---

include commodity price changes, market supply shortages, interest rate changes and counterparty defaults, all of which could have an adverse effect on our financial condition, results of operations and ability to service the bonds.

In addition, the sale of electric power and natural gas is generally a seasonal business, which seasonality results in competitive price fluctuations. Our operating revenue is negatively impacted by low commodity prices resulting from low demand for electricity. Demand for electricity often peaks during the hottest summer months and coldest winter months and declines during the other months. As a result of these variations in demand and resulting price fluctuations, our overall operating results in the future may fluctuate substantially on a seasonal basis. We have historically earned less income when weather conditions are milder. We expect that unusually mild weather in the future could decrease our operating revenue and provide us with fewer funds available to service the bonds. Additionally, a significant portion of PacifiCorp's supply of electricity comes from hydroelectric projects that are dependent upon rainfall and snowpack. During or following periods of low rainfall or snowpack, PacifiCorp may obtain substantially less electricity from hydroelectric projects and must purchase greater amounts of electricity from the wholesale market or from other sources at market prices. This could lead to increased costs to PacifiCorp. Accordingly, our utilities' and pipelines' operating results could be adversely affected by variations in weather conditions.

Also, in Iowa, MidAmerican Energy does not have an ability to pass through fuel price increases in its electric rates, so any significant increase in fuel costs or purchased power costs for electricity generation could have a negative impact on MidAmerican Energy, despite our efforts to minimize this negative impact through the use of hedging instruments. The impact of these risks could result in MidAmerican Energy's inability to fulfill contractual obligations, significantly higher energy or fuel costs relative to corresponding sales contracts or increased interest expense. Any of these consequences could decrease our net cash flow and impair our ability to service the bonds.

PacifiCorp and MidAmerican Energy are subject to market risk and other risks associated with wholesale energy markets and these risks could adversely affect our results of operations and our ability to service the bonds.

In general, 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 and/or demand for electricity and fuel.

PacifiCorp and MidAmerican Energy 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 PacifiCorp or MidAmerican Energy require larger than expected volumes that must be purchased at market or short-term prices, PacifiCorp or MidAmerican Energy may have significantly greater expense than anticipated. In addition, PacifiCorp may not be able to timely recover all, if any, of those increased expenses unless the state regulators authorize such recovery. Likewise, if electricity market prices drop 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 operating revenue. Wholesale electricity prices in PacifiCorp's services areas are influenced primarily by factors throughout the western United States relating to supply and demand. Those factors include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth and changes in technology. Volumetric changes are caused by unanticipated changes in generation availability and/or changes in customer loads due to the weather, the economy or customer behavior. Although PacifiCorp plans for resources to meet its current and expected retail and wholesale load obligations, PacifiCorp's net power costs may be adversely impacted by market risk.

MidAmerican Energy's total accredited net generating capability exceeds its historical peak load. As a result, in comparison to PacifiCorp, which relies to a significant extent on wholesale power purchases to satisfy its load, MidAmerican Energy has less exposure to wholesale electricity market price fluctuations. The actual amount of generation capacity available at any time, however, may be less than the accredited capacity due to regulatory restrictions, transmission constraints, fuel

restrictions and generating units being temporarily out of service for inspection, maintenance, refueling, modifications or other reasons. In such circumstances MidAmerican Energy may need to purchase energy in the wholesale markets and it may not recover in rates all of the additional costs that may be associated with such purchases. Most of MidAmerican Energy's electric wholesale sales and purchases take place under market-based pricing allowed by the FERC and are therefore subject to market volatility. Margins earned on wholesale sales have historically been included as a component of retail cost of service upon which retail rates are based.

PacifiCorp and MidAmerican Energy are also exposed to risk related to performance of contractual obligations by wholesale suppliers and customers. Each utility relies on suppliers to deliver natural gas, coal and electricity in accordance with short- and long-term contracts. Failure or delay by suppliers to provide natural gas, coal or electricity pursuant to existing contracts could disrupt the utilities' ability to deliver electricity and require the utilities to incur additional expenses to meet customer needs. In addition, as these contractual agreements end, the utilities may not be able to continue to purchase natural gas, coal or electricity on terms equivalent to the terms of current contractual agreements. At certain times of the year, prices paid by PacifiCorp, in particular, to obtain certain load balancing resources to satisfy load requirements may exceed the amounts received through retail rates from these loads. If the strategy used to hedge these risk exposures is ineffective, each utility could incur significant losses.

We have significant operations outside the United States which may be subject to increased risk because of the economic or political conditions of the country in which they operate.

We have a number of operations outside of the United States. The acquisition, ownership and operation of businesses outside the United States entails significant political and financial risks (including, without limitation, uncertainties associated with privatization efforts, inflation, currency exchange rate fluctuations, currency repatriation restrictions, changes in law or regulation, changes in government policy, political instability, civil unrest and expropriation) and other risk/structuring issues that have the potential to cause material impairment of the value of the business being operated, which we may not be capable of fully insuring against. The risk of doing business outside of the United States could be greater than in the United States because of specific economic or political conditions of each country. The uncertainty of the legal environment in certain foreign countries in which we operate or may acquire projects or businesses could make it more difficult for us to enforce our rights under agreements relating to such projects or businesses. Our international projects may be subject to the risk of being delayed, suspended or terminated by the applicable foreign governments or may be subject to the risk of contract abrogation, expropriations or other uncertainties resulting from changes in government policy or personnel or changes in general political or economic conditions affecting the country or otherwise. In addition, the laws and regulations of certain countries may limit our ability to hold a majority interest in some of the projects or businesses that we may acquire. Furthermore, the central bank of any such country may have the authority in certain circumstances to suspend, restrict or otherwise impose conditions on foreign exchange transactions or to restrict distributions to foreign investors. Although we may structure certain project operating revenue and other agreements to provide for payments to be made in, or indexed to, United States dollars or a currency freely convertible into United States dollars, there can be no assurance that we will be able to obtain sufficient dollars or other hard currency or that available dollars will be allocated to pay such obligations, which could adversely affect our ability to service the bonds.

We face exchange rate risk.

Payments from some of our foreign investments, including without limitation CE Electric UK, are made in a foreign currency and any dividends or distributions of earnings in respect of such investments may be significantly affected by fluctuations in the exchange rate between the United States dollar and the British pound or other applicable foreign currency, which could adversely affect our financial condition and results of operations. Although we may enter into certain transactions to hedge risks associated with exchange rate fluctuations, there can be no assurance that such transactions will be successful in reducing such risks.

Other Risks Associated with the Bonds and the Exchange Offer

Your ability to transfer the bonds is limited by the absence of a market for the bonds, and a trading market for the bonds may not develop.

There is no existing public trading market for the bonds and a market for the bonds might not develop and you may not be able to sell the bonds or obtain a suitable price. If such a market were to develop, the bonds could trade at prices that may be higher or lower than their initial offering price depending on many factors, including prevailing interest rates, our operating results and the market for similar securities. We do not intend to apply for listing of the bonds on a securities exchange or an automated dealer quotation system. As a result, it may be difficult for you to find a buyer for the bonds at the time you want to sell them and, even if you find a buyer, you might not realize the price you want.

You may not be able to sell your initial 2006 bonds if you do not exchange them for registered exchange 2006 bonds in the exchange offer.

If you do not exchange your initial 2006 bonds for exchange 2006 bonds in the exchange offer, your initial 2006 bonds will continue to be subject to the restrictions on transfer as stated in the legends on the initial 2006 bonds. In general, you may not offer, sell or otherwise transfer the initial 2006 bonds in the United States unless they are:

- registered under the Securities Act;
- offered or sold under an exemption from the Securities Act and applicable state securities laws; or
- offered or sold in a transaction not subject to the Securities Act and applicable state securities laws.

We do not currently anticipate that we will register the initial 2006 bonds under the Securities Act. Except for limited instances involving the initial purchasers or holders of initial 2006 bonds who are not eligible to participate in the exchange offer or who receive freely transferable exchange 2006 bonds in the exchange offer, we will not be under any obligation to register the initial 2006 bonds under the Securities Act under the registration rights agreement or otherwise. Also, if the exchange offer is completed on the terms and within the time period contemplated by this prospectus, no liquidated damages will be payable on your initial 2006 bonds.

Your ability to sell your initial 2006 bonds may be significantly more limited and the price at which you may be able to sell your initial 2006 bonds may be significantly lower if you do not exchange them for registered exchange 2006 bonds in the exchange offer.

To the extent that initial 2006 bonds are exchanged in the exchange offer, the trading market for the initial 2006 bonds that remain outstanding may be significantly more limited. As a result, the liquidity of the initial 2006 bonds not tendered for exchange could be adversely affected. The extent of the market for initial 2006 bonds will depend upon a number of factors, including the number of holders of initial 2006 bonds remaining outstanding and the interest of securities firms in maintaining a market in the initial 2006 bonds. An issue of securities with a lesser outstanding market value available for trading, which is called the ‘‘float,’’ may command a lower price than would be comparable to an issue of securities with a greater float. As a result, the market price for initial 2006 bonds that are not exchanged in the exchange offer may be affected adversely to the extent that initial 2006 bonds exchanged in the exchange offer reduce the float. The reduced float also may make the trading price of the initial 2006 bonds that are not exchanged more volatile.

There are state securities law restrictions on the resale of the exchange 2006 bonds.

In order to comply with the securities laws of certain jurisdictions, the exchange 2006 bonds may not be offered or resold by any holder unless they have been registered or qualified for sale in such jurisdictions or an exemption from registration or qualification is available and the requirements of such exemption have been satisfied. We do not currently intend to register or qualify the resale of the exchange 2006 bonds in any such jurisdictions. However, an exemption is generally available for sales

to registered broker-dealers and certain institutional buyers. Other exemptions under applicable state securities laws may also be available.

We will not accept your initial 2006 bonds for exchange if you fail to follow the exchange offer procedures and, as a result, your initial 2006 bonds will continue to be subject to existing transfer restrictions and you may not be able to sell your initial 2006 bonds.

We will issue exchange 2006 bonds as part of the exchange offer only after a timely receipt of your initial 2006 bonds, a properly completed and duly executed letter of transmittal and all other required documents. Therefore, if you want to tender your initial 2006 bonds, please allow sufficient time to ensure timely delivery. If we do not receive your initial 2006 bonds, letter of transmittal and other required documents by the expiration date of the exchange offer, we will not accept your initial 2006 bonds for exchange. We are under no duty to give notification of defects or irregularities with respect to the tenders of initial 2006 bonds for exchange. If there are defects or irregularities with respect to your tender of initial 2006 bonds, we will not accept your initial 2006 bonds for exchange. See ‘‘The Exchange Offer.’’

Table of Contents

DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus contains statements that do not directly or exclusively relate to historical facts. These statements are ''forward-looking statements'' within the meaning of the Private Securities Litigation Reform Act of 1995. You can typically identify forward-looking statements by the use of forward-looking words, such as ''may,'' ''could,'' ''project,'' ''believe,'' ''anticipate,'' ''expect,'' ''estimate,'' ''continue,'' ''potential,'' ''plan,'' ''forecast,'' and similar terms. These statements are based upon our current intentions, assumptions, expectations and beliefs and are subject to risks, uncertainties and other important factors. Many of these factors are outside our control and could cause actual results to differ materially from those expressed or implied by our forward-looking statements. These factors include, among others:

- general economic, political and business conditions in the jurisdictions in which our facilities are located;
- the financial condition and creditworthiness of our significant customers and suppliers;
- governmental, statutory, legislative, regulatory or administrative initiatives, including those relating to the Energy Policy Act, or ratemaking actions affecting us or the electric or gas utility, pipeline or power generation industries;
- the outcome of general rate cases and other proceedings conducted before regulatory authorities;
- weather effects on sales and operating revenue;
- changes in expected customer growth or usage of electricity or gas;
- economic or industry trends that could impact electricity or gas usage;
- increased competition in the power generation, electric and gas utility or pipeline industries;
- fuel, fuel transportation and power costs and availability;
- continued availability of accessible gas reserves;
- changes in business strategy, development plans or customer or vendor relationships;
- availability, terms and deployment of capital;
- availability of qualified personnel;
- unscheduled outages or repairs;
- risks relating to nuclear generation;
- financial or regulatory accounting principles or policies imposed by the Public Company Accounting Oversight Board, the Financial Accounting Standards Board (or FASB), the U.S. Securities and Exchange Commission (or SEC), the FERC, state public utility commissions, the Ofgem and similar entities with regulatory oversight;
- changes in, and compliance with, environmental laws, regulations, decisions and policies that could increase operating and capital improvement costs or affect plant output and/or delay plant construction;
- our ability to successfully integrate PacifiCorp's operations into our business;
- other risks or unforeseen events, including 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 our SEC filings or in other publicly disseminated written documents.

Further details of the potential risks and uncertainties affecting us are described in the ''Risk Factors'' section of this prospectus. We undertake 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.

Table of Contents

USE OF PROCEEDS

We will not receive any proceeds from the issuance of the exchange 2006 bonds in the exchange offer. The exchange 2006 bonds will evidence the same debt as the initial 2006 bonds tendered in exchange for exchange 2006 bonds. Accordingly, the issuance of the exchange 2006 bonds will not result in any change in our indebtedness.

Table of Contents

THE EXCHANGE OFFER

Purpose of the Exchange Offer

On March 24, 2006, we privately placed the initial 2006 bonds in a transaction exempt from registration under the Securities Act. Accordingly, the initial 2006 bonds may not be reoffered, resold or otherwise transferred in the United States unless so registered or unless an exemption from the Securities Act registration requirements is available. Pursuant to a registration rights agreement with the initial purchasers of the initial 2006 bonds, we agreed, for the benefit of holders of the bonds, to:

- prepare and file an exchange offer registration statement with the SEC with respect to a registered offer to exchange the initial 2006 bonds for exchange 2006 bonds issued under the same indenture as the initial 2006 bonds, in the same aggregate principal amount as and with terms that are identical in all material respects to the initial 2006 bonds except that they will not contain terms with respect to transfer restrictions;

- use our reasonable best efforts to cause the exchange offer registration statement to become effective under the Securities Act on or before December 19, 2006 (within 270 days after March 24, 2006, the date on which we issued the initial 2006 bonds); and

- promptly after the exchange offer registration statement is declared effective, offer the exchange 2006 bonds in exchange for surrender of the initial 2006 bonds.

We will be entitled to consummate the exchange offer on the expiration date provided that we have accepted all initial 2006 bonds previously validly tendered in accordance with the terms set forth in this prospectus and the applicable letter of transmittal.

In addition, under certain circumstances described below, we may be required to file a shelf registration statement to cover resales of the bonds

If we do not comply with certain of our obligations under the registration rights agreement, we must pay liquidated damages on the initial 2006 bonds in addition to the interest that is otherwise due on the bonds. See ''— Liquidated Damages.'' The purpose of the exchange offer is to fulfill our obligations with respect to the registration rights agreement.

If you are a broker-dealer that receives exchange 2006 bonds for its own account in exchange for initial 2006 bonds, where you acquired such initial 2006 bonds as a result of market-making activities or other trading activities, you must acknowledge that you will deliver a prospectus in connection with any resale of such exchange 2006 bonds. See ''Plan of Distribution.''

Terms of the Exchange

Upon the terms and subject to the conditions contained in this prospectus and in the letters of transmittal that accompany this prospectus, we are offering to exchange $1,000 in principal amount of exchange 2006 bonds for each $1,000 in principal amount of initial 2006 bonds. The terms of the exchange 2006 bonds are identical in all material respects to the terms of the initial 2006 bonds except that the exchange 2006 bonds will generally be freely transferable. The exchange 2006 bonds will evidence the same debt as the initial 2006 bonds and will be entitled to the benefits of the indenture. Any initial 2006 bonds that remain outstanding after the consummation of the exchange offer, together with all exchange 2006 bonds issued in connection with the exchange offer, will be treated as a single class of securities under the indenture. See ''Description of Bonds.''

The exchange offer is not conditioned on any minimum aggregate principal amount of initial 2006 bonds being tendered for exchange.

Based on existing interpretations of the Securities Act by the staff of the SEC set forth in several no-action letters to third parties, and subject to the immediately following sentence, we believe that you may offer for resale, resell and otherwise transfer the exchange 2006 bonds without further compliance with the registration and prospectus delivery provisions of the Securities Act. However, if you are an ''affiliate'' (within the meaning of the Securities Act) of ours or you intend to participate in

---

the exchange offer for the purpose of distributing the exchange 2006 bonds or you are a broker-dealer (within the meaning of the Securities Act) that acquired bonds in a transaction other than as part of its market-making or other trading activities and who has arranged or has an understanding with any person to participate in the distribution of the exchange 2006 bonds, you:

(1) will not be able to rely on the interpretations by the staff of the SEC set forth in the above-mentioned no-action letters;

(2) will not be able to tender your bonds in the exchange offer; and

(3) must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any sale or transfer of your bonds unless such sale or transfer is made pursuant to an exemption from such requirements.

Subject to exceptions for certain holders, to participate in the exchange offer you will be required to represent to us at the time of the consummation of the exchange offer, among other things, that: (1) you are not an affiliate of ours; (2) any exchange 2006 bonds to be received by you will be acquired in the ordinary course of your business; and (3) at the time of commencement of the exchange offer, you have no arrangement or understanding with any person to participate in a distribution (within the meaning of the Securities Act) of the bonds. In addition, in connection with any resales of exchange 2006 bonds, any broker-dealer who acquired exchange 2006 bonds for its own account as a result of market-making activities or other trading activities must deliver a prospectus meeting the requirements of the Securities Act. The SEC has taken the position that such a broker-dealer may fulfill its prospectus delivery requirements with respect to the exchange 2006 bonds (other than a resale of an unsold allotment from the initial sale of the initial 2006 bonds) with this prospectus. Under the registration rights agreement, we are required to allow a broker-dealer and other persons with similar prospectus delivery requirements, if any, to use this prospectus connection with the resale of such exchange 2006 bonds for a period of time not less than 120 days following the consummation of the exchange offer. If you are a broker-dealer that receives exchange 2006 bonds for its own account in exchange for initial 2006 bonds, where you acquired such initial 2006 bonds as a result of market-making activities or other trading activities, you must acknowledge that you will deliver a prospectus in connection with any resale of such exchange 2006 bonds. See ''Plan of Distribution.''

You will not be required by us to pay brokerage commissions or fees or, subject to the instructions in the applicable letter of transmittal, transfer taxes relating to your exchange of initial 2006 bonds for exchange 2006 bonds in the exchange offer.

Shelf Registration Statement

If:

- we are not permitted to effect the exchange offer because of any change in law or in applicable interpretations of such law by the staff of the SEC;
- the exchange offer is not consummated by the 40th day after the date on which the exchange offer registration statement was declared effective;
- any of the initial purchasers of the initial 2006 bonds so requests with respect to the initial 2006 bonds not eligible to be exchanged for exchange 2006 bonds in the exchange offer and held by it following the consummation of exchange offer;
- any holder of the bonds (other than a broker-dealer electing to exchange initial 2006 bonds acquired for its own account as a result of market-making or other trading activities for exchange securities) is not eligible to participate in the exchange offer and any such holder so requests for any reason other than the failure by such holder to make a timely and valid tender in accordance with the terms of exchange offer; or

- any holder the bonds (other than a broker-dealer electing to exchange initial 2006 bonds acquired for its own account as a result of market-making or other trading activities for exchange 2006 bonds) participates in the exchange offer but does not receive freely tradable exchange 2006 bonds on the date of the exchange and any such holder so requests for any reason other than the failure by such holder to make a timely and valid tender in accordance with the terms of exchange offer,

we will:

- as promptly as practicable prepare and file with the SEC a ‘‘shelf’’ registration statement relating to the offer and sale (on a continuous basis) of the bonds that are not otherwise freely tradable;
- use our reasonable best efforts to cause the shelf registration statement to be declared effective not later than the later to occur of the date that is 150 days after the date on which our obligation to file the shelf registration arises or December 19, 2006 (270 days after March 24, 2006, the date on which we issued the initial 2006 bonds); and
- use our reasonable best efforts to keep the shelf registration statement continuously effective until the earlier of two years from the date on which we issued the initial 2006 bonds (subject to extension under certain circumstances) and such shorter period ending when all the bonds covered by the shelf registration statement have been sold pursuant to the shelf registration statement or are no longer restricted securities (as defined in Rule 144 under the Securities Act).

You will not be entitled, except if you were an initial purchaser of the initial 2006 bonds, to have your 2006 bonds registered under the shelf registration statement, unless you agree in writing to be bound by the applicable provisions of the registration rights agreement. In order to sell your 2006 bonds under the shelf registration statement, you generally must be named as a selling security holder in the related prospectus and must deliver a prospectus to purchasers. Consequently, you will be subject to the civil liability provisions under the Securities Act in connection with those sales and indemnification obligations under the registration rights agreements.

Additional Interest

A registration default will be deemed to have occurred if:

(1) the exchange offer registration statement is not declared effective on or before December 19, 2006 (within 270 days after March 24, 2006, the date on which we issued the initial 2006 bonds);

(2) the shelf registration statement is not declared effective by the later to occur of the date that is 150 days after the date on which our obligation to file the shelf registration arises or December 19, 2006 (270 days after March 24, 2006, the date on which we issued the initial 2006 bonds); or

(3) after either the exchange offer registration statement or the shelf registration statement is declared effective, such registration statement or the related prospectus thereafter ceases to be effective or usable (subject to certain exceptions) in connection with resales of initial 2006 bonds or exchange 2006 bonds for the periods specified and in accordance with the registration rights agreement because (1) any event occurs as a result of which the related prospectus forming part of such Registration Statement would include any untrue statement of a material fact or omit to state any material fact necessary to make the statements therein in the light of the circumstances under which they were made not misleading, (2) it shall be necessary to amend such Registration Statement or supplement the related prospectus to comply with the Securities Act or the Exchange Act or the respective rules thereunder or (3) of a Suspension by the Company in accordance with provisions and procedures provided in the Registration Rights Agreement.

Additional interest will accrue on the 2006 bonds subject to such registration default at a rate of 0.50% per annum from and including the date on which any such registration default occurs to but

excluding the date on which all such registration defaults have ceased to be continuing. In each case, such additional interest is payable in addition to any other interest payable from time to time with respect to the initial 2006 bonds and the exchange 2006 bonds. The exchange 2006 bonds will not contain any provisions regarding the payment of liquidated damages.

Expiration Date; Extensions; Termination; Amendments

The exchange offer expires on the expiration date. The expiration date is 5:00 p.m., New York City time, on October 11, 2006, unless we in our sole discretion extend the period during which the exchange offer is open, in which event the expiration date is the latest time and date on which the exchange offer, as so extended by us, expires. We reserve the right to extend the exchange offer at any time and from time to time prior to the expiration date by giving written notice to The Bank of New York, N.A., as the exchange agent, and by timely public announcement communicated in accordance with applicable law or regulation. During any extension of the exchange offer, all initial 2006 bonds previously tendered pursuant to the exchange offer and not validly withdrawn will remain subject to the exchange offer.

The exchange date will occur promptly after the expiration date. We expressly reserve the right to (i) terminate the exchange offer and not accept for exchange any initial 2006 bonds for any reason, including if any of the events set forth below under ‘‘- Conditions to the Exchange Offer’’ shall have occurred and shall not have been waived by us and (ii) amend the terms of the exchange offer in any manner, whether before or after any tender of the initial 2006 bonds. If any such termination or amendment occurs, we will notify the exchange agent in writing and will either issue a press release or give written notice to the holders of the initial 2006 bonds as promptly as practicable. Unless we terminate the exchange offer prior to 5:00 p.m., New York City time, on the expiration date, we will exchange the initial 2006 bonds for the exchange 2006 bonds on the exchange date.

If we waive any material condition to the exchange offer, or amend the exchange offer in any other material respect, and if at the time that notice of such waiver or amendment is first published, sent or given to holders of initial 2006 bonds in the manner specified above, the exchange offer is scheduled to expire at any time earlier than the expiration of a period ending on the fifth business day from, and including, the date that such notice is first so published, sent or given, then the exchange offer will be extended until the expiration of such period of five business days.

This prospectus and the related letters of transmittal and other relevant materials will be mailed by us to record holders of initial 2006 bonds and will be furnished to brokers, banks and similar persons whose names, or the names of whose nominees, appear on the lists of holders for subsequent transmittal to beneficial owners of initial 2006 bonds.

How to Tender

The tender to us of initial 2006 bonds by you pursuant to one of the procedures set forth below will constitute an agreement between you and us in accordance with the terms and subject to the conditions set forth herein and in the applicable letter of transmittal.

General Procedures. A holder of initial 2006 bonds may tender such initial 2006 bonds by (i) properly completing and signing the applicable letter of transmittal or a facsimile thereof (all references in this prospectus to the letter of transmittal shall be deemed to include a facsimile thereof) and delivering the same, together with the certificate or certificates representing the initial 2006 bonds being tendered and any required signature guarantees (or a timely confirmation of a book-entry transfer, which we refer to as a Book-Entry Confirmation, pursuant to the procedure described below), to the exchange agent at its address set forth on the back cover of this prospectus on or prior to the expiration date or (ii) complying with the guaranteed delivery procedures described below.

If tendered initial 2006 bonds are registered in the name of the signer of the letter of transmittal and the exchange 2006 bonds to be issued in exchange therefor are to be issued (and any untendered initial 2006 bonds are to be reissued) in the name of the registered holder, the signature of such signer need not be guaranteed. In any other case, the tendered initial 2006 bonds must be endorsed or accompanied by written instruments of transfer in form satisfactory to us and duly executed by the

---

registered holder and the signature on the endorsement or instrument of transfer must be guaranteed by a firm, which we refer to as an Eligible Institution, that is a member of a recognized signature guarantee medallion program, which we refer to as an Eligible Program, within the meaning of Rule 17Ad-15 under the Securities and Exchange Act of 1934. If the exchange 2006 bonds and/or initial 2006 bonds not exchanged are to be delivered to an address other than that of the registered holder appearing on the note register for the initial 2006 bonds, the signature on the letter of transmittal must be guaranteed by an Eligible Institution.

Any beneficial owner whose initial 2006 bonds are registered in the name of a broker, dealer, commercial bank, trust company or other nominee and who wishes to tender initial 2006 bonds should contact such holder promptly and instruct such holder to tender initial 2006 bonds on such beneficial owner’s behalf. If such beneficial owner wishes to tender such initial 2006 bonds himself, such beneficial owner must, prior to completing and executing the letter of transmittal and delivering such initial 2006 bonds, either make appropriate arrangements to register ownership of the initial 2006 bonds in such beneficial owner’s name or follow the procedures described in the immediately preceding paragraph. The transfer of record ownership may take considerable time.

Book-Entry Transfer. The exchange agent will make a request to establish an account with respect to the initial 2006 bonds at The Depository Trust Company, which we refer to as the Book-Entry Transfer Facility, for purposes of the exchange offer within two business days after receipt of this prospectus, and any financial institution that is a participant in the Book-Entry Transfer Facility’s systems may make book-entry delivery of initial 2006 bonds by causing the Book-Entry Transfer Facility to transfer such initial 2006 bonds into the exchange agent’s account at the Book-Entry Transfer Facility in accordance with the Book-Entry Transfer Facility’s procedures for transfer. However, although delivery of initial 2006 bonds may be effected through book-entry transfer at the Book-Entry Transfer Facility, the letter of transmittal, with any required signature guarantees and any other required documents, must, in any case, be transmitted to and received by the exchange agent at the address specified on the back cover page of this prospectus on or prior to the expiration date or the guaranteed delivery procedures described below must be complied with.

The method of delivery of initial 2006 bonds and all other documents is at your election and risk. If sent by mail, we recommend that you use registered mail, return receipt requested, obtain proper insurance, and complete the

mailing sufficiently in advance of the expiration date to permit delivery to the exchange agent on or before the expiration date.

Guaranteed Delivery Procedures. If a holder desires to accept the exchange offer and time will not permit a letter of transmittal or initial 2006 bonds to reach the exchange agent before the expiration date, a tender may be effected if the exchange agent has received at its office listed on the back cover hereof on or prior to the expiration date a letter, telegram or facsimile transmission from an Eligible Institution setting forth the name and address of the tendering holder, the names in which the initial 2006 bonds are registered, the principal amount of the initial 2006 bonds and, if possible, the certificate numbers of the initial 2006 bonds to be tendered, and stating that the tender is being made thereby and guaranteeing that within three New York Stock Exchange trading days after the date of execution of such letter, telegram or facsimile transmission by the Eligible Institution, the initial 2006 bonds, in proper form for transfer, will be delivered by such Eligible Institution together with a properly completed and duly executed letter of transmittal (and any other required documents). Unless initial 2006 bonds being tendered by the above-described method (or a timely Book-Entry Confirmation) are deposited with the exchange agent within the time period set forth above (accompanied or preceded by a properly completed letter of transmittal and any other required documents), we may, at our option, reject the tender. Copies of a Notice of Guaranteed Delivery which may be used by Eligible Institutions for the purposes described in this paragraph are being delivered with this prospectus and the related letter of transmittal.

A tender will be deemed to have been received as of the date when the tendering holder's properly completed and duly signed letter of transmittal accompanied by the initial 2006 bonds (or a timely Book-Entry Confirmation) is received by the exchange agent. Issuances of exchange 2006 bonds in exchange for initial 2006 bonds tendered pursuant to a Notice of Guaranteed Delivery or

letter, telegram or facsimile transmission to similar effect (as provided above) by an Eligible Institution will be made only against deposit of the letter of transmittal (and any other required documents) and the tendered initial 2006 bonds (or a timely Book-Entry Confirmation).

All questions as to the validity, form, eligibility (including time of receipt) and acceptance for exchange of any tender of initial 2006 bonds will be determined by us and our determination will be final and binding. We reserve the absolute right to reject any or all tenders not in proper form or the acceptances for exchange of which may, in the opinion of our counsel, be unlawful. We also reserve the absolute right to waive any of the conditions of the exchange offer or any defect or irregularities in tenders of any particular holder whether or not similar defects or irregularities are waived in the case of other holders. None of us, the exchange agent or any other person will be under any duty to give notification of any defects or irregularities in tenders or shall incur any liability for failure to give any such notification. Our interpretation of the terms and conditions of the exchange offer (including the letters of transmittal and the instructions thereto) will be final and binding.

Terms and Conditions of the Letters of Transmittal

The letters of transmittal contain, among other things, the following terms and conditions, which are part of the exchange offer.

The party tendering initial 2006 bonds for exchange, whom we refer to as the Transferor, exchanges, assigns and transfers the initial 2006 bonds to us and irrevocably constitutes and appoints the exchange agent as the Transferor's agent and attorney-in-fact to cause the initial 2006 bonds to be assigned, transferred and exchanged. The Transferor represents and warrants that it has full power and authority to tender, exchange, assign and transfer the initial 2006 bonds and to acquire exchange 2006 bonds issuable upon the exchange of such tendered initial 2006 bonds, and that, when the same are accepted for exchange, we will acquire good and unencumbered title to the tendered initial 2006 bonds, free and clear of all liens, restrictions, charges and encumbrances and not subject to any adverse claim. The Transferor also warrants that it will, upon request, execute and deliver any additional documents deemed by us to be necessary or desirable to complete the exchange, assignment and transfer of tendered initial 2006 bonds. The Transferor further agrees that acceptance of any tendered initial 2006 bonds by us and the issuance of exchange 2006 bonds in exchange therefor shall constitute performance in full by us of our obligations under the registration rights agreement and that we shall have no further obligations or liabilities thereunder (except in certain limited circumstances). All authority conferred by the Transferor will survive the death or incapacity of the Transferor and every obligation of the Transferor shall be binding upon the heirs, legal representatives, successors, assigns, executors and administrators of such Transferor.

See ''— Terms of the Exchange.''

Withdrawal Rights

Initial 2006 bonds tendered pursuant to the exchange offer may be withdrawn at any time prior to the expiration date. For a withdrawal to be effective, a written or facsimile transmission notice of withdrawal must be timely received by the exchange agent at its address set forth on the back cover of this prospectus. Any such notice of withdrawal must specify the person named in the letter of transmittal as having tendered initial 2006 bonds to be withdrawn, the certificate numbers of initial 2006 bonds to be withdrawn, the principal amount of initial 2006 bonds to be withdrawn (which must be an authorized denomination), a statement that such holder is withdrawing his election to have such initial 2006 bonds exchanged, and the name of the registered holder of such initial 2006 bonds, and must be signed by the holder in the same manner as the original signature on the letter of transmittal (including any required signature guarantees) or be accompanied by evidence satisfactory to us that the person withdrawing the tender has succeeded to the beneficial ownership of the initial 2006 bonds being withdrawn. The exchange agent will return the properly withdrawn initial 2006 bonds promptly following receipt of notice of withdrawal. All questions as to the validity of notices of withdrawals, including time of receipt, will be determined by us, and our determination will be final and binding on all parties.

Acceptance of Original Bonds for Exchange; Delivery of Exchange Bonds

Upon the terms and subject to the conditions of the exchange offer, the acceptance for exchange of initial 2006 bonds validly tendered and not withdrawn and the issuance of the exchange 2006 bonds will be made on the exchange date. For the purposes of the exchange offer, we shall be deemed to have accepted for exchange validly tendered initial 2006 bonds when, as and if we have given written notice thereof to the exchange agent.

The exchange agent will act as agent for the tendering holders of initial 2006 bonds for the purposes of receiving exchange 2006 bonds from us and causing the initial 2006 bonds to be assigned, transferred and exchanged. Upon the terms and subject to the conditions of the exchange offer, delivery of exchange 2006 bonds to be issued in exchange for accepted initial 2006 bonds will be made by the exchange agent promptly after acceptance of the tendered initial 2006 bonds. Initial 2006 bonds not accepted for exchange by us will be returned without expense to the tendering holders (or in the case of initial 2006 bonds tendered by book-entry transfer into the exchange agent's account at the Book-Entry Transfer Facility pursuant to the procedures described above, such non-exchanged initial 2006 bonds will be credited to an account maintained with such Book-Entry Transfer Facility) promptly following the expiration date or, if we terminate the exchange offer prior to the expiration date, promptly after the exchange offer is so terminated.

Conditions to the Exchange Offer

We are not required to accept for exchange, or to issue exchange 2006 bonds in exchange for, any outstanding initial 2006 bonds. We may terminate or extend the exchange offer by oral or written notice to the exchange agent and by timely public announcement communicated in accordance with applicable law or regulation, if:

- any federal law, statute, rule, regulation or interpretation of the staff of the SEC has been proposed, adopted or enacted that, in our judgment, might impair our ability to proceed with the exchange offer or otherwise make it inadvisable to proceed with the exchange offer;
- an action or proceeding has been instituted or threatened in any court or by *any* governmental agency that, in our judgment might impair our ability to proceed with the exchange offer or otherwise make it inadvisable to proceed with the exchange offer;
- there has occurred a material adverse development in any existing action or proceeding that might impair our ability to proceed with the exchange offer or otherwise make it inadvisable to proceed with the exchange offer;
- any stop order is threatened or in effect with respect to the registration statement of which this prospectus is a part or the qualification of the indenture under the Trust Indenture Act of 1939;
- all governmental approvals that we deem necessary for the consummation of the exchange offer have not been obtained;
- there is a change in the current interpretation by the staff of the SEC which permits holders who have made the required representations to us to resell, offer for resale, or otherwise transfer exchange 2006 bonds issued in the exchange offer without registration of the exchange 2006 bonds and delivery of a prospectus; or
- a material adverse change shall have occurred in our business, condition, operations or prospects.

The foregoing conditions are for our sole benefit and may be asserted by us with respect to all or any portion of the exchange offer regardless of the circumstances (including any action or inaction by us) giving rise to such condition or may be waived by us in whole or in part at any time or from time to time in our sole discretion. The failure by us at any time to exercise any of the foregoing rights will not be deemed a waiver of any such right, and each right will be deemed an ongoing right which may be asserted at any time or from time to time. In addition, we have reserved the right, notwithstanding the satisfaction of each of the foregoing conditions, to terminate or amend the exchange offer.

Any determination by us concerning the fulfillment or non-fulfillment of any conditions will be final and binding upon all parties.

Exchange Agent

The Bank of New York Trust Company, N.A. has been appointed as the exchange agent for the exchange offer. Letters of transmittal must be addressed to the exchange agent at its address set forth on the back cover page of this prospectus. Delivery to an address other than as set forth herein, or transmissions of instructions via a facsimile or telex number other than the ones set forth herein, will not constitute a valid delivery. The Bank of New York Trust Company, N.A. is the trustee under the indenture. The Bank of New York Trust Company, N.A. (or one of its affiliates) currently serves, and may in the future serve, as trustee under indentures evidencing other indebtedness of MEHC and its affiliates. The Bank of New York Trust Company, N.A. (or one of its affiliates) is also, and may in the future be, a lender under credit facilities for MEHC and its affiliates.

Solicitation of Tenders; Expenses

We have not retained any dealer-manager or similar agent in connection with the exchange offer and will not make any payments to brokers, dealers or others for soliciting acceptances of the exchange offer. We will, however, pay the exchange agent reasonable and customary fees for its services and will reimburse it for reasonable out-of-pocket expenses in connection therewith. We will also pay brokerage houses and other custodians, nominees and fiduciaries the reasonable out-of-pocket expenses incurred by them in forwarding tenders for their customers. The expenses to be incurred in connection with the exchange offer, including the fees and expenses of the exchange agent and printing, accounting and legal fees, will be paid by us and are estimated at approximately $250,000.

No dealer, salesperson or other individual has been authorized to give any information or to make any representations not contained in this prospectus in connection with the exchange offer. If given or made, such information or representations must not be relied upon as having been authorized by us. Neither the delivery of this prospectus nor any exchange made hereunder shall, under any circumstances, create any implication that there has been no change in our affairs since the respective dates as of which information is given herein.

The exchange offer is not being made to (nor will tenders be accepted from or on behalf of) holders of initial 2006 bonds in any jurisdiction in which the making of the exchange offer or the acceptance thereof would not be in compliance with the laws of such jurisdiction. However, we may, at our discretion, take such action as we may deem necessary to make the exchange offer in any such jurisdiction and extend the exchange offer to holders of initial 2006 bonds in such jurisdiction. In any jurisdiction the securities laws or blue sky laws of which require the exchange offer to be made by a licensed broker or dealer, the exchange offer is being made on behalf of us by one or more registered brokers or dealers which are licensed under the laws of such jurisdiction.

Appraisal Rights

You will not have appraisal rights in connection with the exchange offer.

Federal Income Tax Consequences

The exchange of initial 2006 bonds for exchange 2006 bonds will not be a taxable exchange for U.S. federal income tax purposes, and holders will not recognize any taxable gain or loss or any interest income as a result of such exchange. See ‘‘Certain United States Federal Income Tax Considerations.’’

Other

Participation in the exchange offer is voluntary and you should carefully consider whether to accept. You are urged to consult your financial and tax advisors in making your own decisions on what action to take.

As a result of the making of, and upon acceptance for exchange of all validly tendered initial 2006 bonds pursuant to the terms of this exchange offer, we will have fulfilled a covenant contained in the terms of the initial 2006 bonds and the registration rights agreement. Holders of the initial 2006 bonds who do not tender their initial 2006 bonds in the exchange offer will continue to hold such initial 2006 bonds and will be entitled to all the rights, and limitations applicable thereto, under the indenture, except for any such rights under the registration rights agreement which by their terms terminate or cease to have further effect as a result of the making of this exchange offer. See ‘‘Description of Bonds.’’ All untendered initial 2006 bonds will continue to be subject to the restriction on transfer set forth in the indenture. To the extent that initial 2006 bonds are tendered and accepted in the exchange offer, the trading market, if any, for the initial 2006 bonds could be adversely affected. See ‘‘Risk Factors – Your ability to sell your initial 2006 bonds may be significantly more limited and the price at which you may be able to sell your initial 2006 bonds may be significantly lower if you do not exchange them for registered exchange 2006 bonds in the exchange offer.’’

We may in the future seek to acquire untendered initial 2006 bonds in open market or privately negotiated transactions, through subsequent exchange offers or otherwise. We have no present plan to acquire any initial 2006 bonds which are not tendered in the exchange offer.

CAPITALIZATION

The following table sets forth our consolidated capitalization as of June 30, 2006 (in millions). The table should be read in conjunction with our selected historical financial and operating data and our historical financial statements and notes thereto included elsewhere in this prospectus.

Consolidated indebtedness:	
Short-term debt	$ 317.5
Current portion of long-term debt	502.3
Current portion of parent company subordinated debt — Berkshire Hathaway	234.0
Parent company senior debt	4,477.1
Parent company subordinated debt — Berkshire Hathaway	988.2
Parent company subordinated debt — other	300.1
Subsidiary and project debt	10,540.8
Total consolidated indebtedness	17,360.0
Preferred securities of subsidiaries	129.1
Minority interest	83.6
Stockholders' equity:	
Common stock — 115.0 shares authorized, no par value; 74.2 shares issued and outstanding	—
Additional paid-in capital	5,393.6
Retained earnings	2,083.6
Accumulated other comprehensive loss, net	(141.7)
Total stockholders' equity	7,335.5

Total capitalization	$24,908.2

Table of Contents

SELECTED HISTORICAL FINANCIAL AND OPERATING DATA

MidAmerican Energy Holdings Company

The following table sets forth our selected consolidated historical financial and operating data, which should be read in conjunction with our historical consolidated financial statements and notes thereto included elsewhere in this prospectus. The selected consolidated historical financial and operating data as of and for the six months ended June 30, 2006 and 2005, have been derived from our interim unaudited historical consolidated financial statements and notes thereto included elsewhere in this prospectus. In the opinion of management, these unaudited historical consolidated financial statements include all normal recurring adjustments necessary for a fair presentation. The selected consolidated historical financial and operating data as of December 31, 2005 and 2004 and for each of the three years in the period ended December 31, 2005, have been derived from our audited historical consolidated financial statements and notes thereto included elsewhere in this prospectus. The selected consolidated historical financial and operating data as of December 31, 2003, 2002 and 2001 and for the years ended December 31, 2002 and 2001 have been derived from our audited historical consolidated financial statements and notes thereto not included in this prospectus.

	Six Months Ended June 30,		Years Ended December 31,				
	2006(1)	2005	2005	2004	2003	2002(2)	2001
	(in millions)						
Consolidated Statement of Operations Data:							
Operating revenue	$4,672.1	$3,408.6	$7,115.5	$6,553.4	$5,965.6	$4,795.2	$4,696.8
Depreciation and amortization	492.0	297.0	608.2	638.2	602.9	530.1	533.6
Total costs and expenses(3)	3,737.7	2,649.5	5,586.8	5,028.0	4,515.8	3,622.5	3,823.7
Operating income	934.4	759.1	1,528.7	1,525.4	1,449.8	1,172.7	873.1
Interest expense, net of capitalized interest(4)	514.9	447.5	874.3	883.2	730.5	608.8	412.5
Income from continuing operations	402.0	249.1	557.5	537.8	442.7	397.4	153.0
Income (loss) from discontinued operations(5)	—	3.0	5.1	(367.6)	(27.1)	(17.4)	(5.7)
Cumulative effect of accounting change	—	—	—	—	—	—	(4.6)
Net income available to common and preferred stockholders	402.0	252.1	562.6	170.2	415.6	380.0	142.7

	As of June 30,	As of December 31,				
	2006(1)	2005	2004	2003	2002(2)	2001
	(in millions)					
Consolidated Balance Sheet Data:						
Properties, plant and equipment, net	$22,647.0	$11,915.4	$11,607.3	$11,181.0	$10,284.5	$ 6,902.6
Total assets	34,997.9	20,370.7	19,903.6	19,145.0	18,434.9	12,994.6
Short-term debt	317.5	70.1	9.1	48.0	79.8	256.0
Long-term debt, including current maturities: Parent company senior debt	4,477.1	2,776.2	3,032.0	2,777.9	2,538.4	1,834.5
Parent company subordinated debt — Berkshire Hathaway	1,222.2	1,289.2	1,477.8	1,577.8	—	—
Parent company subordinated debt — other	300.1	298.9	296.6	294.4	—	—
Company-obligated mandatorily redeemable preferred securities of subsidiary trusts — Berkshire	—	—	—	—	1,727.8	454.8
Company-obligated mandatorily redeemable preferred securities of subsidiary trusts — other	—	—	—	—	335.6	333.4
Subsidiary and project debt	11,043.1	7,150.3	7,190.5	7,175.5	7,332.3	5,072.0
Subsidiary-obligated mandatorily redeemable preferred securities of subsidiary trusts	—	—	—	—	—	100.0
Preferred securities of subsidiaries	129.1	88.4	89.5	92.1	93.3	121.2
Total stockholders' equity	7,335.5	3,385.2	2,971.2	2,771.4	2,294.3	1,708.2

Table of Contents

	Six Months Ended June 30,		Years Ended December 31,				
	2006(1)	2005	2005	2004	2003	2002(2)	2001
	(in millions, except ratios)						
Other Consolidated Financial Data:							
Capital expenditures	$ 917.5	$ 508.8	$ 1,196.2	$ 1,179.4	$ 1,219.4	$ 1,342.3	$ 576.8
Ratio of earnings to fixed charges(6)	2.1x	1.8x	1.8x	1.9x	1.7x	1.6x	1.5x
Net cash flows from operating activities	$ 952.9	$ 861.1	$ 1,310.8	$ 1,424.6	$ 1,217.9	$ 757.7	$ 847.0
Net cash flows from investing activities	(5,790.3)	(972.9)	(1,551.3)	(1,098.1)	(1,094.0)	(2,978.1)	(229.9)
Net cash flows from financing activities	4,871.8	117.9	(219.1)	(105.4)	(358.1)	2,575.5	(267.1)
EBITDA(7)	1,621.8	1,128.2	2,289.8	1,956.6	2,019.3	1,630.2	1,342.9
Adjusted EBITDA(7)	1,426.4	1,056.1	2,136.8	2,163.6	2,052.7	1,702.8	1,406.7

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

(2) Reflects the acquisitions of Kern River on March 27, 2002 and Northern Natural Gas on August 16, 2002.

(3) Includes a $54.3 million pre-tax gain related to the sale of certain U.K. natural gas assets during the year ended December 31, 2002, and a $196.7 million pre-tax gain related to the sale of Northern Electric’s supply business during the year ended December 31, 2001.

(4) We adopted and applied the provisions of FASB Interpretation No. 46R, ''Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51,'' (or FIN 46R) relating to certain finance subsidiaries as of October 1, 2003. The adoption required the deconsolidation of certain finance subsidiaries, which resulted in amounts that were previously recorded as preferred dividends of subsidiaries being prospectively recorded as interest expense. For the six-month periods ended June 30, 2006 and 2005, the years ended December 31, 2005 and 2004, and the three-month period ended December 31, 2003, we recorded $84.3 million, $94.9 million, $184.4 million, $196.9 million and $49.8 million, respectively, of interest expense related to these securities. In accordance with the requirements of FIN 46R, no amounts prior to adoption of FIN 46R on October 1, 2003 have been reclassified. The amounts included in preferred dividends of subsidiaries related to these securities for the nine-month period ended September 30, 2003, and the years ended December 31, 2002 and 2001 were $170.2 million, $147.7 million and $80.1 million, respectively.

(5) An indirect wholly owned subsidiary of ours owned a facility in California designed to recover zinc from geothermal brine. Effective September 10, 2004, management ceased the operation of the facility, which resulted in a non-cash, after-tax impairment charge of $340.3 million being recorded to write off the facility's assets, rights to quantities of extractable minerals, and allocated goodwill. The charge and related activity, including the reclassification of such activity for all periods presented, are classified separately as discontinued operations. Substantially all of the remainder of the loss from discontinued operations in 2004 and all of the losses from discontinued operations during the years ended December 31, 2003, 2002 and 2001 reflect losses incurred from operating the facility. The income from discontinued operations in 2005 reflects the proceeds received from the sale of assets, partially offset by the disposal costs incurred, in connection with the dismantling and decommissioning of the facility.

(6) For purposes of calculating the ratio of earnings to fixed charges, earnings are divided by fixed charges. Earnings represent the aggregate of (a) income from continuing operations before income taxes, minority interest and equity income, (b) fixed charges, and (c) distributions from equity investees, less capitalized interest (both from continuing and discontinued operations). Fixed charges represent the aggregate of (a) interest costs (both expensed and capitalized and from continuing and discontinued operations), (b) amortization of deferred financing costs and unamortized discounts or premiums relating to any indebtedness, (c) estimated interest portion of rental payments, and (d) pre-tax earnings required to cover any preferred stock dividend requirements of subsidiaries, which represents preferred dividends multiplied by the ratio which pre-tax income from continuing operations bears to income from continuing operations.

(7) EBITDA is defined as net income available to common and preferred stockholders plus interest expense, capitalized interest, income tax expense and depreciation and amortization. ''Adjusted EBITDA'' represents operating income plus depreciation and amortization and is computed as follows:

	Six Months Ended June 30,		Years Ended December 31,				
	2006	2005	2005	2004	2003	2002	2001
			(in millions)				
Operating income	$ 934.4	$ 759.1	$1,528.7	$1,525.4	$1,449.8	$1,172.7	$ 873.1
Depreciation and amortization	492.0	297.0	608.2	638.2	602.9	530.1	533.6
Adjusted EBITDA	$1,426.4	$1,056.1	$2,136.9	$2,163.6	$2,052.7	$1,702.8	$1,406.7

Table of Contents

Adjusted EBITDA is also defined as EBITDA adjusted to give effect to interest and dividend income, other income (expense), minority interest and preferred dividends of subsidiaries, equity income, and loss (income) from discontinued operations as follows:

	Six Months Ended June 30,		Years Ended December 31,				
	2006	2005	2005	2004	2003	2002	2001
			(in millions)				
Net income available to common and preferred stockholders	$ 402.0	$ 252.1	$ 562.6	$ 170.2	$ 415.6	$ 380.0	$ 142.7
Interest expense	529.8	455.7	891.0	903.2	761.0	632.1	479.5
Capitalized interest	(14.9)	(8.2)	(16.7)	(20.0)	(30.5)	(23.3)	(67.0)
Income tax expense	212.9	131.6	244.7	265.0	270.3	111.3	254.1
Depreciation and amortization	492.0	297.0	608.2	638.2	602.9	530.1	533.6
EBITDA	1,621.8	1,128.2	2,289.8	1,956.6	2,019.3	1,630.2	1,342.9
Interest and dividend income	(33.6)	(23.4)	(58.1)	(38.9)	(47.9)	(56.0)	(23.8)
Other income (expense)	(166.0)	(34.2)	(52.4)	(118.1)	(90.7)	(11.7)	10.2
Minority interest and preferred dividends of subsidiaries	13.9	6.6	16.0	13.3	183.2	163.4	106.6
Equity income	(9.7)	(18.1)	(53.3)	(16.9)	(38.3)	(40.5)	(39.5)
Loss (income) from discontinued operations, net of tax	—	(3.0)	(5.2)	367.6	27.1	17.4	5.7
Cumulative effect of accounting change	—	—	—	—	—	—	4.6
Adjusted EBITDA	$1,426.4	$1,056.1	$2,136.8	$2,163.6	$2,052.7	$1,702.8	$1,406.7

We present Adjusted EBITDA because we consider it an important supplemental measure of our performance and believe it is frequently used by securities analysts, investors and other interested parties in the evaluation of companies in our industry.

We also use Adjusted EBITDA in the preparation of annual operating budgets. Adjusted EBITDA is used as one measure, by us and others within our industry to evaluate and price potential acquisition candidates.

Adjusted EBITDA has limitations as an analytical tool, and you should not consider it in isolation, or as a substitute for analysis of our results as reported under accounting principles generally accepted in the United States of America (or GAAP). EBITDA is subject to the same limitations as Adjusted EBITDA.

- Adjusted EBITDA does not reflect our cash expenditures, future requirements for capital expenditures or contractual commitments, changes in, or cash requirements for, our working capital needs, interest expense, or the cash requirements necessary to service interest or principal payments, on our debts.
- Other companies in our industry may calculate Adjusted EBITDA differently than we do, limiting its usefulness as a comparative measure.

Because of these limitations, Adjusted EBITDA should not be considered as a measure of discretionary cash available to us to invest in the growth of our business. We compensate for these limitations by relying primarily on our GAAP results and using Adjusted EBITDA only supplementally.

EBITDA and Adjusted EBITDA presented in this table are measures of our performance that are not required by, or presented in accordance with, GAAP. EBITDA and Adjusted EBITDA are not measurements of our financial performance under GAAP and should not be considered as an alternative to net income, operating income or any other performance measures derived in accordance with GAAP or as an alternative to cash flow from operating activities as a measure of our liquidity.

Table of Contents

PacifiCorp

The following table sets forth PacifiCorp's selected consolidated historical financial and operating data, which should be read in conjunction with PacifiCorp's historical consolidated financial statements and notes thereto included elsewhere in this prospectus. The selected consolidated historical financial and operating data as of and for the quarters ended June 30, 2006 and 2005, have been derived from PacifiCorp's interim unaudited historical condensed consolidated financial statements and notes thereto included elsewhere in this prospectus. In the opinion of management, these unaudited historical condensed consolidated financial statements include all normal recurring adjustments necessary for a fair presentation. The selected consolidated historical financial and operating data as of March 31, 2006 and 2005 and for each of the three years in the period ended March 31, 2006, have been derived from PacifiCorp's audited historical consolidated financial statements and notes thereto included elsewhere in this prospectus. The selected consolidated historical financial and operating data as of March 31, 2004, 2003 and 2002 and for the years ended March 31, 2003 and 2002 have been derived from PacifiCorp's audited historical consolidated financial statements and notes thereto not included in this prospectus.

	Quarters Ended June 30,		Years Ended March 31,				
	2006(1)	2005	2006	2005	2004	2003	2002
			(in millions)				
Consolidated Statement of Operations Data:							
Revenues	$859.9	$881.4	$3,896.7	$3,048.8	$3,194.5	$3,082.4	$3,353.7
Depreciation and amortization	115.7	110.9	448.3	436.9	428.8	434.3	403.0
Total operating expenses	737.5	745.5	3,104.7	2,392.4	2,576.6	2,593.5	2,712.7
Income from operations	122.4	135.9	792.0	656.4	617.9	488.9	641.0
Interest expense, net of interest capitalized	64.4	64.9	261.4	258.6	248.8	262.5	220.8
Income from continuing operations	42.6	46.4	360.7	251.7	249.0	142.0	293.4
Income from discontinued operations(2)	—	—	—	—	—	—	146.7
Cumulative effect of accounting change(3)	—	—	—	—	(0.9)	(1.9)	(112.8)
Net income	42.6	46.4	360.7	251.7	248.1	140.1	327.3
Preferred dividend requirement	0.5	0.5	2.1	2.1	3.3	7.3	12.7
Earnings on common stock	42.1	45.9	358.6	249.6	244.8	132.8	314.6

	As of June 30,	As of March 31,				
	2006(1)	2006	2005	2004	2003	2002
		(in millions)				
Consolidated Balance Sheet Data:						
Property, plant and equipment, net	$10,252.2	$10,109.2	$ 9,490.6	$ 9,036.5	$ 8,698.5	$ 7,969.5
Total assets	12,856.7	12,731.3	12,520.9	11,677.1	11,695.8	10,234.9
Notes payable and commercial paper	304.2	184.4	468.8	124.9	25.0	177.5
Long-term debt and capital lease obligations, including current maturities	3,936.6	3,937.9	3,898.9	3,760.2	3,554.3	3,698.3
Guaranteed preferred beneficial interests in PacifiCorp's junior subordinated debentures	—	—	—	—	341.8	341.5
Preferred stock subject to mandatory redemption, including current maturities	37.5	45.0	52.5	60.0	66.7	74.2
Total shareholders' equity	4,162.6	4,051.8	3,377.1	3,320.0	3,235.7	2,933.2

Table of Contents

	Quarters Ended June 30,		Years Ended March 31,				
	2006(1)	2005	2006	2005	2004	2003	2002
			(in millions, except ratios)				
Other Consolidated Financial Data:							
Capital expenditures	$ 289.6	$ 230.6	$ 1,049.0	$ 851.6	$ 690.4	$ 550.0	$ 505.3
Ratio of earnings to fixed charges(4)	1.9x	2.1x	2.9x	2.5x	2.4x	1.7x	2.7x
Net cash flows from operating activities	$ 62.0	$ 140.1	$ 894.6	$ 711.1	$ 831.9	$ 681.6	$ 342.6
Net cash flows from investing activities	(294.7)	(230.1)	(1,024.1)	(846.7)	(703.5)	(525.1)	(568.4)
Net cash flows from financing activities	186.2	58.2	49.8	276.4	(222.4)	(161.9)	244.3
EBITDA(5)	245.6	253.6	1,267.7	1,113.6	1,066.9	926.8	1,114.5
Adjusted EBITDA(5)	238.1	246.8	1,240.3	1,093.3	1,046.7	923.2	1,044.0

(1) The selected consolidated historical financial and operating data as of and for the quarter ended June 30, 2006 reflect PacifiCorp's historical basis of accounting and do not reflect any adjustments related to our acquisition of PacifiCorp.

(2) The year ended March 31, 2002 includes the collection of a contingent note receivable relating to the discontinued operations of a former mining and resource development business, NERCO, Inc.

(3) The year ended March 31, 2002, reflects the effect of the implementation of Statement of Financial Accounting Standards (or SFAS) No. 133, ''Accounting for Derivative Instruments and Hedging Activities'' (or SFAS 133).

(4) For purposes of calculating the ratio of earnings to fixed charges, earnings represent the aggregate of (a) income from continuing operations, (b) taxes based on income from continuing operations, (c) minority interest in the income of majority-owned subsidiaries that have fixed charges, (d) fixed charges and (e) undistributed income of less than 50% owned affiliates without loan guarantees. Fixed charges represent consolidated interest charges, an estimated amount representing the interest factor in rents and preferred dividends of wholly owned subsidiaries. Preferred dividends of wholly owned subsidiaries represents preferred dividends multiplied by the ratio which pre-tax income from continuing operations bears to income from continuing operations.

(5) EBITDA is defined as earnings on common stock plus interest expense, interest capitalized, income tax expense and depreciation and amortization. Adjusted EBITDA represents income from operations plus depreciation and amortization and is computed as follows:

	Quarters Ended June 30,		Years Ended March 31,				
	2006	2005	2006	2005	2004	2003	2002
			(in millions)				
Income from operations	$122.4	$135.9	$ 792.0	$ 656.4	$ 617.9	$488.9	$ 641.0
Depreciation and amortization	115.7	110.9	448.3	436.9	428.8	434.3	403.0
Adjusted EBITDA	$238.1	$246.8	$1,240.3	$1,093.3	$1,046.7	$923.2	$1,044.0

Table of Contents

Adjusted EBITDA is also defined as EBITDA adjusted to give effect to interest income, minority interest and other, cumulative effect of accounting change, and preferred dividend requirement and can be reconciled to earnings on common stock as follows:

	Quarters Ended June 30,		Years Ended March 31,				
	2006	2005	2006	2005	2004	2003	2002
			(in millions)				
Earnings on common stock	$ 42.1	$ 45.9	$ 358.6	$ 249.6	$ 244.8	$132.8	$ 314.6
Interest expense	69.2	69.3	279.9	267.4	256.5	270.3	227.7
Interest capitalized	(4.8)	(4.4)	(18.5)	(8.8)	(7.7)	(7.8)	(6.9)
Income tax expense	23.4	31.9	199.4	168.5	144.5	97.2	176.1
Depreciation and amortization	115.7	110.9	448.3	436.9	428.8	434.3	403.0
EBITDA	245.6	253.6	1,267.7	1,113.6	1,066.9	926.8	1,114.5
Interest income	(1.6)	(2.7)	(9.5)	(9.1)	(13.8)	(21.6)	(47.5)
Minority interest and other	(6.4)	(4.6)	(20.0)	(13.3)	(10.6)	8.8	(1.8)
Income from discontinued operations	—	—	—	—	—	—	(146.7)
Cumulative effect of accounting change	—	—	—	—	0.9	1.9	112.8
Preferred dividend requirement	0.5	0.5	2.1	2.1	3.3	7.3	12.7
Adjusted EBITDA	$238.1	$246.8	$1,240.3	$1,093.3	$1,046.7	$923.2	$1,044.0

We present Adjusted EBITDA because we consider it an important supplemental measure of PacifiCorp's performance and believe it is frequently used by securities analysts, investors and other interested parties in the evaluation of companies in our industry.

We also use Adjusted EBITDA in the preparation of annual operating budgets. Adjusted EBITDA is used as one measure, by us and others within our industry to evaluate and price potential acquisition candidates.

Adjusted EBITDA has limitations as an analytical tool, and you should not consider it in isolation, or as a substitute for analysis of PacifiCorp's results as reported under GAAP. EBITDA is subject to the same limitations as Adjusted EBITDA.

- Adjusted EBITDA does not reflect PacifiCorp's cash expenditures, future requirements for capital expenditures or contractual commitments, changes in, or cash requirements for, PacifiCorp's working capital needs, interest expense, or the cash requirements necessary to service interest or principal payments, on PacifiCorp's debts.
- Other companies in our industry may calculate Adjusted EBITDA differently than it has been calculated for PacifiCorp, limiting its usefulness as a comparative measure.

Because of these limitations, Adjusted EBITDA should not be considered as a measure of discretionary cash available to PacifiCorp to invest in the growth of its business.

EBITDA and Adjusted EBITDA presented in this table are measures of PacifiCorp's performance that are not required by, or presented in accordance with, GAAP. EBITDA and Adjusted EBITDA are not measurements of PacifiCorp's financial performance under GAAP and should not be considered as an alternative to net income, operating income or any other performance measures derived in accordance with GAAP or as an alternative to cash flow from operating activities as a measure of PacifiCorp's liquidity.

Table of Contents

SUMMARY SELECTED HISTORICAL AND UNAUDITED PRO FORMA FINANCIAL DATA

The following table sets forth our summary selected historical and unaudited pro forma financial data for the six months ended June 30, 2006 and the year ended December 31, 2005 as if the following had occurred on January 1, 2005: (i) our $5.1 billion acquisition of PacifiCorp and (ii) the issuance of $1.7 billion of 6.125% senior unsecured bonds due in 2036. The table should be read in conjunction with the unaudited pro forma condensed combined consolidated statements of operations and notes thereto included elsewhere in this prospectus.

	Six Months Ended June 30, 2006		Year Ended December 31, 2005	
	MEHC Historical	MEHC Pro Forma	MEHC Historical	MEHC Pro Forma
			(in millions)	
Statements of Operations Data:				
Operating revenue	$4,672.1	$5,823.9	$7,115.5	$10,402.9
Depreciation and amortization	492.0	591.3	608.2	1,054.0
Total costs and expenses	3,737.7	4,649.7	5,586.8	8,146.6
Operating income	934.4	1,174.2	1,528.7	2,256.3

Interest expense, net of amounts capitalized	514.9	623.7	874.3	1,239.6
Income from continuing operations	402.0	505.6	557.5	796.2

Table of Contents

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following is management's discussion and analysis of certain significant factors which have affected our consolidated financial condition and results of operations during the periods included herein. This discussion should be read in conjunction with our historical unaudited interim consolidated financial statements and the related notes thereto and our historical audited consolidated financial statements included in the ‘‘Financial Statements’’ section of this prospectus. Our actual results in the future could differ significantly from the historical results.

Executive Summary

Our operations are organized and managed as eight distinct platforms: PacifiCorp, MidAmerican Funding, which primarily includes MidAmerican Energy, Northern Natural Gas, Kern River, CE Electric UK, which primarily includes Northern Electric and Yorkshire Electricity, CalEnergy Generation-Foreign, CalEnergy Generation-Domestic and HomeServices. Through these platforms, we own and operate an electric utility company in the western United States, a combined electric and natural gas utility company in the midwestern United States, two natural gas pipeline companies in the United States, two electricity distribution companies in Great Britain, a diversified portfolio of domestic and international independent power projects and the second-largest residential real estate brokerage firm in the United States.

The following significant events and changes that occurred during 2006, as discussed in more detail elsewhere in this prospectus, highlight some of the factors which affected, or may affect in the future, our financial condition, results of operations and liquidity:

- In May 2005, we reached a definitive agreement with ScottishPower to acquire 100% of the common stock of ScottishPower’s wholly owned indirect subsidiary PacifiCorp for $5,109.5 million in cash. On March 21, 2006, we issued common stock of $5,109.5 million to Berkshire Hathaway and other existing stockholders and closed the PacifiCorp acquisition. The results of PacifiCorp are included in our results beginning March 21, 2006.
- On February 9, 2006, following the effective date of the repeal of the Public Utility Holding Company Act of 1935 (or PUHCA 1935), Berkshire Hathaway converted its 41,263,395 shares of our no par, zero-coupon convertible preferred stock into an equal number of shares of our common stock. As a consequence, Berkshire Hathaway owns in excess of 80.0% of our outstanding common stock, consolidates us in its financial statements as a majority-owned subsidiary, and will include us in its consolidated federal U.S. income tax return.
- On March 1, 2006, we and Berkshire Hathaway entered into an Equity Commitment Agreement (or the Berkshire Equity Commitment) pursuant to which Berkshire Hathaway agreed to purchase up to $3.5 billion of our common equity through February 28, 2011.
- On March 24, 2006, we completed the $1,700.0 million offering of the initial 2006 bonds. The initial 2006 bonds were issued at an offering price of 99.957%, accrue interest at a rate of 6.125% per annum and will mature on April 1, 2036.
- On March 28, 2006, we exercised our right to repurchase $1,700.0 million of our common stock from Berkshire Hathaway.
- In the first quarter of 2006, Kern River sold all of the shares of Mirant Americas Energy Marketing (or Mirant) stock received in February 2006 from its allowed bankruptcy claim amount plus interest and realized after-tax gains from such sales of $55.3 million.
- MidAmerican Funding’s operating income for the second quarter and the first six months of 2006 increased $20.6 million, or 35.2%, and $55.8 million, or 35.3%, respectively, from the comparable periods in 2005 due primarily to improvements in MidAmerican Energy’s gross margin from regulated electric retail and wholesale sales.

Table of Contents

- Northern Natural Gas’ operating income for the second quarter and the first six months of 2006 decreased $19.1 million, or 49.6%, and $5.9 million, or 3.9%, respectively, from the comparable periods in 2005 due mainly to the net favorable effects ($18.5 million in the second quarter and $16.0 million in the first six months) of two rate case settlements approved by the FERC during the first six months of 2005. Additionally, Northern Natural Gas recognized a $19.7 million gain from the sale of an idled section of pipeline in Oklahoma and Texas in the second quarter of 2005. These items were partially offset by favorable comparative second quarter and first six months operating results in 2006 versus 2005.
- Kern River filed for a rate increase with the FERC in April 2004, with the new rates placed into effect on November 1, 2004, subject to refund. The general rate case hearing concluded in August 2005 and Kern River received an adverse initial decision on the case from the administrative law judge on March 2, 2006, which, among other things, proposed an authorized equity rate of return of 9.34%. Kern River is currently authorized to collect an authorized equity rate of return of 13.25%. The final resolution of the rate case is dependent on receiving a final, non-appealable decision on the case from the FERC, or approval of a settlement of the case by the FERC, which is not expected at the earliest until late 2006 or early 2007.
- HomeServices’ operating income for the second quarter and the first six months of 2006 decreased $15.9 million, or 31.3%, and $24.2 million, or 41.1%, respectively, from the comparable periods in 2005 due mainly to fewer

brokerage transactions, particularly in the California and Minnesota markets, partially offset by the results of acquired companies not included in the comparable 2005 periods.

- MidAmerican Energy has continued its construction of electric generation facilities in Iowa by placing in-service 900.5 MW (nameplate rating) of capacity, in the aggregate, during the three years in the period ended December 31, 2005. Projects completed include the 540-MW (nameplate rating) combined-cycle Greater Des Moines Energy Center in 2003 and 2004 and 360.5 MW (nameplate rating) of wind turbines in 2005 and 2004. Additionally, MidAmerican Energy is currently constructing Council Bluffs Energy Center Unit No. 4 (or CBEC Unit 4), a 790-MW (expected accreditation) super-critical-temperature, low sulfur coal-fired generating plant of which MidAmerican Energy's current ownership interest is 60.67%, equating to 479 MW of output, and MidAmerican Energy expects to invest approximately $737 million in the project through 2007. Through June 30, 2006, MidAmerican Energy had invested $594.0 million in the project, including $121.3 million for MidAmerican Energy's share of deferred payments allowed by the construction contract. MidAmerican Energy received approval in April 2006 from the IUB to add up to 545 MW (nameplate rating) of wind-powered generation capacity in Iowa, of which it has committed to construct approximately 222 MW to be installed in 2006 and 2007.

- PacifiCorp is currently constructing the Lake Side Power Plant, an estimated 550-MW combined-cycle plant in Utah, expected to be in service by the summer of 2007. The cost of the Lake Side Power Plant is expected to total approximately $347 million, of which approximately $251 million has been incurred through June 30, 2006. In July 2006, PacifiCorp entered into an agreement to acquire a 100.5-MW (nameplate rating) wind-powered generation facility that is expected to begin commercial operation in the third quarter of 2006.

- On August 10, 2006, PacifiCorp issued $350.0 million of 6.10%, 30-year first mortgage bonds. The proceeds from that offering are being used to repay a portion of PacifiCorp's short-term debt and for general corporate purposes.

In addition to the items described in the preceding 2006 discussion, the following significant events and changes that occurred during the years ended December 31, 2005, 2004 and 2003, as discussed in more detail elsewhere in this prospectus, also highlight some of the factors which affected, or may affect in the future, our financial condition, results of operations and liquidity:

- Indirect wholly owned subsidiaries of ours own the rights to commercial quantities of extractable minerals from elements in solution in the geothermal brine and fluids utilized at certain geothermal plants in the Imperial Valley of California and owned a zinc recovery plant constructed near the Imperial Valley Projects designed to recover zinc from the geothermal brine through an ion exchange, solvent extraction, electrowinning and casting process (or the Zinc Recovery Project). On September 10, 2004, management made the decision to cease operations of the Zinc Recovery Project. Implementation of the decommissioning plan began in September 2004 and as of December 31, 2005, the dismantling, decommissioning, and sale of remaining assets of the Zinc Recovery Project was completed.

- Kern River completed construction of its 2003 Expansion Project in May 2003 at a total cost of $1.2 billion.

- Ofgem completed the process of reviewing the existing price control formula for Northern Electric and Yorkshire Electricity in November 2004. As a result of the review, the allowed revenues of Northern Electric's and Yorkshire Electricity's distribution businesses were reduced by 4% and 9%, respectively, in real terms, effective April 1, 2005.

- CE Casecnan Water and Energy Company, Inc. (or CE Casecnan) reached an arbitration settlement with the National Irrigation (or NIA) effective during the fourth quarter of 2003. In exchange for the receipt of approximately $18 million of cash and a $97.0 million Republic of the Philippines (or ROP) Note, CE Casecnan agreed to modify certain provisions of its project agreement, the most significant of which are the elimination of the tax compensation portion of the water delivery fee and modification of the threshold volume of water used to calculate the guaranteed water delivery fee.

- In February 2004, we issued $250.0 million of our 5.00% senior notes due February 15, 2014. The proceeds were used to satisfy a demand made by an affiliate on our guarantee of certain debt related to the Zinc Recovery Project and for general corporate purposes.

- MidAmerican Energy issued $300.0 million of 5.75%, 30-year, medium-term notes on November 1, 2005, and $350.0 million of 4.65%, 10-year, medium-term notes on October 1, 2004. The proceeds from each offering are being used to support construction of its electric generation projects and for general corporate purposes.

- On May 5, 2005, certain subsidiaries of CE Electric UK collectively issued £350.0 million of 5.125% senior bonds due 2035. The proceeds from the offerings are being invested and used for general corporate purposes. Proceeds from the maturing investments will be used to repay certain long-term debt of subsidiaries of CE Electric UK in 2007 and 2008.

Results of Operations – Second Quarter and First Six Months of 2006 and 2005

Consolidated Executive Summary

Consolidated statement of operations results for the second quarter and the first six months of 2006 and 2005 are summarized in the following table (in millions):

	Second Quarter		First Six Months	
	2006	2005	2006	2005
Operating revenue	$2,617.5	$1,604.4	$4,672.1	$3,408.6
Operating income	$ 471.9	$ 334.6	$ 934.4	$ 759.1
Interest expense	(308.1)	(224.1)	(529.8)	(455.7)
Other income, net	72.9	36.1	214.5	65.8
Income tax expense	(81.7)	(57.6)	(212.9)	(131.6)
Minority interest and preferred dividends of subsidiaries	(9.9)	(3.8)	(13.9)	(6.6)
Equity income	7.9	13.2	9.7	18.1
Income from continuing operations	153.0	98.4	402.0	249.1
Income from discontinued operations, net of income tax	—	1.3	—	3.0
Net income available to common and preferred stockholders	$ 153.0	$ 99.7	$ 402.0	$ 252.1

Net income for the second quarter of 2006 increased $53.3 million, or 53.5%, to $153.0 million from the comparable period in 2005. Net income from PacifiCorp was $44.5 million. Favorable comparative second quarter operating results at MidAmerican Funding, Northern Natural Gas, Kern River and CE Electric UK more than offset lower operating results at HomeServices, lower equity earnings at CE Generation, LLC (or CE Generation) and HomeServices and higher interest expense at MEHC. Additionally, in the second quarter of 2006, MidAmerican Funding recognized an after-tax gain of $18.0 million on the disposition of the common shares it held in an electronic energy and metals trading exchange and, in the second quarter of 2005, after-tax gains were recognized of $12.0 million related to the sale of an idled section of pipeline in Oklahoma and Texas, and $10.5 million related to the settlement of outstanding rate cases at Northern Natural Gas and of $5.9 million from the sale of a non-strategic investment.

Net income for the first six months of 2006 increased $149.9 million, or 59.5%, to $402.0 million from the comparable period in 2005. Net income from PacifiCorp was $54.8 million during the period from acquisition to June 30, 2006. In addition to the items described in the second quarter discussion above, an after-tax gain of $55.3 million was recognized from the sale of Mirant common stock received as part of Kern River's Mirant bankruptcy claim award in the first six months of 2006. Also in the first six months of 2006, a $10.9 million unrealized, after-tax loss at CalEnergy Gas (Holdings) Limited (or CE Gas) related to its Australian gas production hedges was recognized. Favorable comparative first six months operating results at CalEnergy Generation-Foreign resulted from higher water flow and electricity generation.

Segment Results

The reportable segment financial information includes all necessary adjustments and eliminations needed to conform to our 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, intersegment eliminations and fair value adjustments relating to acquisitions. Additionally, the activity of our Mineral Assets, which was previously reported in the CalEnergy Generation-Domestic reportable segment, is presented as discontinued operations within the consolidated financial statements included in the ''Financial Statements'' section of this prospectus.

A comparison of operating revenue and operating income for the Company's reportable segments for the second quarter and the first six months of 2006 and 2005 follows (in millions):

	Second Quarter		First Six Months	
	2006	2005	2006	2005
Operating revenue:				
PacifiCorp	$ 859.9	$ —	$ 936.4	$ —
MidAmerican Funding	761.6	619.7	1,803.3	1,476.0
Northern Natural Gas	103.0	61.9	316.7	263.1
Kern River	86.2	79.2	165.5	157.8
CE Electric UK	215.9	214.9	426.3	454.1
CalEnergy Generation — Foreign	73.8	72.1	159.1	144.3
CalEnergy Generation — Domestic	8.0	8.7	15.5	16.6
HomeServices	517.4	554.2	872.9	916.5
Total reportable segments	2,625.8	1,610.7	4,695.7	3,428.4
Corporate/other	(8.3)	(6.3)	(23.6)	(19.8)
Total operating revenue	$2,617.5	$1,604.4	$4,672.1	$3,408.6
Operating income:				
PacifiCorp	$ 130.8	$ —	$ 153.3	$ —
MidAmerican Funding	79.2	58.6	213.7	157.9
Northern Natural Gas	19.4	38.5	143.8	149.7
Kern River	52.0	47.9	92.2	97.0
CE Electric UK	117.3	114.9	231.3	240.6
CalEnergy Generation — Foreign	43.9	43.4	101.3	87.2
CalEnergy Generation — Domestic	3.5	5.2	6.5	9.5
HomeServices	34.9	50.8	34.7	58.9
Total reportable segments	481.0	359.3	976.8	800.8
Corporate/other	(9.1)	(24.7)	(42.4)	(41.7)
Total operating income	$ 471.9	$ 334.6	$ 934.4	$ 759.1

PacifiCorp

On March 21, 2006, MEHC acquired 100% of the common stock of PacifiCorp. Operating revenue and operating income of $859.9 million and $130.8 million, respectively, and $936.4 million and $153.3 million, respectively, from PacifiCorp's operations are included in the Company's results for the second quarter of 2006 and for the period from acquisition to June 30, 2006. Operating revenue for the period from acquisition to June 30, 2006 consisted of retail and wholesale and other revenues totaling

$778.4 million and $158.0 million, respectively. PacifiCorp recorded $31.6 million of unrealized losses under SFAS 133, as amended, during the period from acquisition to June 30, 2006, related to mark-to-market movements. PacifiCorp uses derivative instruments (primarily forward purchases and sales) to manage the commodity price risk inherent in its fuel and electricity obligations, as well as to optimize the value of power generation assets and related contracts.

Table of Contents

MidAmerican Funding

MidAmerican Funding's operating revenue and operating income for the second quarter and the first six months of 2006 and 2005 are summarized as follows (in millions):

	Second Quarter		First Six Months	
	2006	2005	2006	2005
Operating revenue:				
Regulated electric	$460.6	$347.3	$ 875.8	$ 659.9
Regulated natural gas	169.0	210.0	624.8	677.4
Nonregulated	132.0	62.4	302.7	138.7
Total operating revenue	$761.6	$619.7	$1,803.3	$1,476.0
Operating income:				
Regulated electric	$ 82.5	$ 60.3	$ 181.7	$ 121.4
Regulated natural gas	(1.4)	(3.2)	30.2	31.4
Nonregulated	(1.9)	1.5	1.8	5.1
Total operating income	$ 79.2	$ 58.6	$ 213.7	$ 157.9

Regulated Electric Operations

The operating results of MidAmerican Energy's regulated electric business for the second quarter and the first six months of 2006 and 2005 are summarized as follows (in millions, except for average number of customers):

	Second Quarter		First Six Months	
	2006	2005	2006	2005
Retail	$ 312.4	$ 293.8	$ 602.1	$ 561.0
Wholesale	148.2	53.5	273.7	98.9
Total operating revenue	460.6	347.3	875.8	659.9
Cost of fuel, energy and capacity	169.0	102.6	304.6	191.4
Margin	291.6	244.7	571.2	468.5
Operating expense	129.9	118.6	243.2	225.5
Depreciation and amortization	79.2	65.8	146.3	121.6
Operating income	$ 82.5	$ 60.3	$ 181.7	$ 121.4
Sales (gigawatt-hours):				
Retail	4,803	4,529	9,596	8,941
Wholesale	3,236	2,049	5,739	3,768
	8,039	6,578	15,335	12,709
Average number of customers	708,634	696,208	708,273	699,080

MidAmerican Energy's regulated electric retail revenue for the second quarter and for the first six months of 2006 increased $18.6 million, or 6.3%, to $312.4 million and $41.1 million, or 7.3%, to $602.1 million, respectively, from the comparable periods in 2005. Electric retail sales volumes increased 6.0% compared to the second quarter of 2005. A growing retail customer base improved electric retail revenue by $12.7 million, while electricity usage factors not dependent on weather, such as the size of homes, technology changes and the use of multiple appliances, increased electric revenue by $5.1 million compared to the second quarter of 2005. Electric retail sales volumes increased 7.3% compared to the first six months of 2005. A growing retail customer base improved electric retail revenue by $24.6 million, while electricity usage factors not dependent on weather increased electric revenue by $11.9 million compared to the first six months of 2005.

In addition to retail sales, MidAmerican Energy sells electric energy, or wholesale sales, to other utilities, marketers and municipalities. MidAmerican Energy's wholesale revenue for the second

Table of Contents

quarter and for the first six months of 2006 increased $94.7 million, or 177.0%, to $148.2 million and $174.8 million, or 176.7%, to $273.7 million, respectively, from the comparable periods in 2005. The effect of higher electric energy prices increased wholesale energy revenue in the second quarter and in the first six months of 2006 by $63.8 million and $123.2 million, respectively. Wholesale units for the second quarter and for the first six months of 2006 increased 57.9% and 52.3%, respectively, from the comparable periods in 2005, resulting in increases in revenue of $31.0 million and $51.7 million, respectively. The primary reason for the increases in wholesale sales volumes for the second quarter and for the first six months of 2006 was additional available MidAmerican Energy-owned, base load generation, including generation available as a result of newly added wind generation supplying retail customers, as well as market opportunities.

Cost of fuel, energy and capacity for the second quarter and for the first six months of 2006 increased $66.4 million, or 64.7%, to $169.0 million and $113.2 million, or 59.1%, to $304.6 million, respectively, from the comparable periods in 2005 due to an increase in the average cost of purchased power and the increase in sales volumes.

Regulated electric operating expense for the second quarter and for the first six months of 2006 increased $11.3 million, or 9.5%, to $129.9 million and $17.7 million, or

7.8%, to $243.2 million, respectively, from the comparable periods in 2005 due mainly to higher transmission operations costs of $6.6 million and $12.6 million, respectively, related to the increase in purchased power and wholesale sales.

Regulated electric depreciation and amortization expense for the second quarter and for the first six months of 2006 increased $13.4 million to $79.2 million and $24.7 million to $146.3 million, respectively, from the comparable periods in 2005 due to increases of $12.0 million and $21.0 million, respectively, in regulatory expense pursuant to a revenue sharing arrangement with the state of Iowa due to higher Iowa electric equity returns. Other increases were due primarily to 200 MW of wind power facilities placed in service in late 2005.

Regulated Natural Gas Operations

Regulated natural gas revenue includes purchased gas adjustment clauses through which MidAmerican Energy is allowed to recover the cost of gas sold from its retail gas utility customers. Consequently, fluctuations in the cost of gas sold do not affect gross margin or operating income because revenues reflect comparable fluctuations through the purchased gas adjustment clauses. Compared to the second quarter of 2005, sales volumes decreased 19.3% for the second quarter of 2006, resulting in a $32.2 million decrease in revenue and cost of gas sold due to milder temperature conditions and other usage factors. In addition, MidAmerican Energy's average per-unit cost of gas sold for the second quarter of 2006 decreased 6.7%, resulting in a $9.1 million decrease in revenue and cost of gas sold from the comparable period in 2005. Compared to the first six months of 2005, sales volumes decreased 16.8% for the first six months of 2006, resulting in a $92.9 million decrease in revenue and cost of gas sold due to milder temperature conditions and other usage factors. Partially offsetting the decrease from lower sales volumes was a 9.7% increase in MidAmerican Energy's average per-unit cost of gas sold for the first six months of 2006, resulting in a $44.5 million increase in revenue and cost of gas sold from the comparable period in 2005.

Nonregulated Operations

MidAmerican Funding's nonregulated operating revenue for the second quarter and for the first six months of 2006 increased $69.6 million, or 111.5%, to $132.0 million and $164.0 million, or 118.2%, to $302.7 million, respectively, from the comparable periods in 2005 due primarily to a change in management strategy related to certain end-use natural gas contracts that resulted in recording prospectively the related revenues and cost of sales on a gross, rather than net, basis in accordance with Emerging Issues Task Force Issue No. 02-3, ''Recognition and Reporting of Gains and Losses on Energy Trading Contracts Under Issues No. 98-10 and 00-17.''

Northern Natural Gas

Operating revenue for the second quarter and for the first six months of 2006 increased $41.1 million, or 66.4%, to $103.0 million and $53.6 million, or 20.4%, to $316.7 million, respectively,

---

from the comparable periods in 2005. These increases were partially attributable to the net effects of two FERC-approved rate settlements that reduced operating revenue in the second quarter and the first six months of 2005 by $22.7 million and $9.1 million, respectively. Transportation and storage revenues in the second quarter and the first six months of 2006 also increased $13.4 million and $28.1 million, respectively, from the comparable periods in 2005 due to increased field area demand and rates as well as new transportation contracts and contract extensions. Additionally, gas and liquids sales increased $5.0 million and $16.4 million, respectively, in the second quarter and in the first six months of 2006 due to higher sales of gas from operational storage utilized to manage physical flows on the pipeline system.

Cost of sales for the second quarter and for the first six months of 2006 increased $4.3 million to $11.0 million and $14.6 million to $22.3 million, respectively, from the comparable periods in 2005 due to higher gas and liquids sales resulting from higher sales of gas from operational storage utilized to manage physical flows on the pipeline system.

Operating expense for the second quarter and for the first six months of 2006 increased $27.6 million, or 82.8%, to $60.8 million and $19.5 million, or 18.7%, to $123.9 million, respectively, from the comparable periods in 2005. These increases were largely due to the $19.7 million gain recorded in the second quarter of 2005 on the sale of an idled section of pipeline in Oklahoma and Texas. The second quarter increase was also partially attributable to the net effects of two FERC-approved rate settlements that reduced operating expense in the second quarter of 2005 by $12.5 million.

Depreciation and amortization for the second quarter and for the first six months of 2006 increased $28.5 million to $14.2 million and $25.5 million to $28.4 million, respectively, from the comparable periods in 2005 due primarily to the net effects and the ongoing impact of changes in the useful lives of Northern Natural Gas' transmission, storage and intangible assets resulting from the June 2005 settlement of its consolidated rate case proceeding.

Kern River

Operating revenue for the second quarter and for the first six months of 2006 increased $7.0 million, or 8.8%, to $86.2 million and $7.7 million, or 4.9%, to $165.5 million, respectively, from the comparable periods in 2005. The increases in operating revenue resulted primarily from higher transportation revenues due mainly to higher quantities and higher rates resulting from more favorable market conditions.

Depreciation and amortization for the second quarter and for the first six months of 2006 increased $4.4 million to $20.0 million and $15.4 million to $46.6 million, respectively, from the comparable periods in 2005 due to higher expected depreciation rates in connection with the current rate proceeding.

CE Electric UK

Operating revenue for the first six months of 2006 decreased $27.8 million, or 6.1%, to $426.3 million from the comparable period in 2005 due mainly to a $20.6 million adverse impact from the exchange rate and a $15.2 million unrealized loss at CE Gas related to its derivative condensate contracts, which are marked to market, partially offset by $7.3 million of higher distribution revenues at Northern Electric and Yorkshire Electricity.

Operating expense for the first six months of 2006 decreased $12.7 million, or 15.1%, to $71.2 million from the comparable period in 2005 due mainly to lower costs of $5.9 million associated with the withdrawal from the metering market and a $3.7 million favorable impact from the exchange rate.

Depreciation and amortization for the first six months of 2006 decreased $5.4 million to $64.4 million from the comparable period in 2005 due mainly to $3.1 million of Yorkshire Electricity out-performance amortization recognized in the first quarter of 2005 and a $3.1 million favorable impact from the exchange rate.

CalEnergy Generation-Foreign

Operating revenue for the first six months of 2006 increased $14.8 million, or 10.3%, to $159.1 million from the comparable period in 2005, mainly due to higher variable energy fees of $11.2 million as a result of significantly higher water flows and corresponding higher variable energy fees at CE Casecnan.

HomeServices

Operating revenue for the second quarter of 2006 decreased $36.8 million, or 6.6%, to $517.4 million and cost of sales decreased $28.6 million, or 7.4%, to $355.7 million from the comparable period in 2005. The decreases in operating revenue and cost of sales were due to a decline from existing businesses totaling $75.8 million and $55.3 million, respectively, reflecting primarily fewer brokerage transactions, particularly in the California and Minnesota markets, partially offset by the results of acquired companies not included in the comparable 2005 period totaling $39.0 million and $26.7 million, respectively.

Operating revenue for the first six months of 2006 decreased $43.6 million, or 4.8%, to $872.9 million and cost of sales decreased $33.2 million, or 5.2%, to $601.3 million from the comparable period in 2005. The decreases in operating revenue and cost of sales were due to a decline from existing businesses totaling $89.5 million and $64.9 million, respectively, reflecting primarily fewer brokerage transactions, particularly in the California and Minnesota markets, partially offset by the results of acquired companies not included in the comparable 2005 period totaling $45.9 million and $31.7 million, respectively.

Operating expense for the second quarter and for the first six months of 2006 increased $1.5 million, or 1.3%, to $116.2 million and $6.9 million, or 3.2%, to $221.3 million, respectively, from the comparable periods in 2005 mainly due to $7.5 million and $9.2 million, respectively, in operating expense related to the results of acquired companies not included in the comparable 2005 periods, partially offset by $6.0 million and $2.3 million, respectively, in lower operating expense at existing businesses due primarily to lower compensation expenses.

Depreciation and amortization for the second quarter and for the first six months of 2006 increased $6.2 million to $10.6 million and $6.9 million to $15.6 million, respectively, from the comparable periods in 2005 due primarily to higher amortization of acquisition related costs.

Consolidated Other Income and Expense Items

Interest Expense

Interest expense for the second quarter and for the first six months of 2006 and 2005 is summarized as follows (in millions):

	Second Quarter		First Six Months	
	2006	2005	2006	2005
Subsidiary short-term and long-term debt	$202.4	$132.1	$340.4	$271.1
Parent company short-term and senior debt	63.7	44.5	105.1	89.7
Parent company subordinated debt-Berkshire	35.1	40.6	70.6	81.3
Parent company subordinated debt-other	6.9	6.9	13.7	13.6
Total interest expense	$308.1	$224.1	$529.8	$455.7

Interest expense on subsidiary short-term and long-term debt for the second quarter and for the first six months of 2006 increased $70.2 million to $202.4 million and $69.2 million to $340.4 million, respectively, from the comparable periods in 2005 due primarily to PacifiCorp's interest expense, which totaled $69.2 million and $77.4 million, respectively, during the second quarter of 2006 and the period from acquisition to June 30, 2006. Additionally, interest expense on subsidiary short-term and long-term debt was higher in the second quarter and the first six months of 2006 compared to the

same periods in 2005 due to MidAmerican Energy's 5.75% $300.0 million debt issuance in November 2005. These increases were partially offset by a $10.2 million charge incurred in February 2005 to exercise the call option on the £155.0 million Variable Rate Reset Trust Securities at CE Electric UK as well as maturities of and scheduled principal repayments on subsidiary and project debt.

Interest expense on parent company short-term and senior debt for the second quarter and for the first six months of 2006 increased $19.3 million to $63.7 million and $15.5 million to $105.1 million, respectively, from the comparable periods in 2005 due primarily to MEHC's 6.125% $1,700.0 million debt issuance in March 2006.

Interest expense on parent company subordinated debt-Berkshire for the second quarter and for the first six months of 2006 decreased $5.5 million to $35.1 million and

$10.7 million to $70.6 million, respectively, from the comparable periods in 2005 due to scheduled principal repayments.

Other Income, Net

Other income, net for the second quarter and for the first six months of 2006 and 2005 is summarized as follows (in millions):

	Second Quarter		First Six Months	
	2006	2005	2006	2005
Capitalized interest	$10.3	$ 4.6	$ 14.9	$ 8.2
Interest and dividend income	18.2	15.0	33.6	23.4
Other income	51.7	18.0	174.6	39.0
Other expense	(7.3)	(1.5)	(8.6)	(4.8)
Total other income, net	$72.9	$36.1	$214.5	$65.8

Capitalized interest for the second quarter and for the first six months of 2006 increased $5.7 million to $10.3 million and $6.7 million to $14.9 million, respectively, from the comparable periods in 2005 due mainly to $4.8 million and $5.3 million, respectively, attributable to PacifiCorp and higher capitalized interest at MidAmerican Energy associated with an increase in the construction of generation facilities.

Interest and dividend income for the second quarter and for the first six months of 2006 increased $3.2 million to $18.2 million and $10.2 million to $33.6 million, respectively, from the comparable periods in 2005 mainly due to $2.4 million and $2.7 million, respectively, attributable to PacifiCorp and earnings on guaranteed investment contracts (£100.0 million at 4.75% and £200.0 million at 4.73%) purchased in May 2005, at CE Electric UK as well as earnings on higher cash balances and higher short-term interest rates.

Other income for the second quarter and for the first six months of 2006 increased $33.7 million to $51.7 million and $135.6 million to $174.6 million, respectively, from the comparable periods in 2005. Other income in the first quarter of 2006 included Kern River's $89.3 million of gains from the sales of Mirant stock, MidAmerican Funding's realized gain of $7.3 million from the sale of a non-strategic investment and Northern Natural Gas' gain of $5.4 million from a contractual settlement. Other income in the second quarter of 2006 included MidAmerican Funding's $32.1 million of gains from the disposition of the common shares it held in an electronic energy and metals trading exchange. Other income in the first quarter of 2005 included MidAmerican Funding's realized gains of $9.9 million from the sales of certain non-strategic investments. Other income in the second quarter of 2005 included CE Electric UK's realized gain of $8.4 million from the sale of a non-strategic investment. Additionally, the allowance for equity funds used during construction for the second quarter and for the first six months of 2006 increased $9.0 million and $11.8 million, respectively, from the comparable periods in 2005 due mainly to $6.6 million attributable to PacifiCorp and increased levels of capital project expenditures at MidAmerican Energy.

In January 2006, Mirant emerged from bankruptcy and on February 6, 2006, a stipulated judgment was entered that allowed Kern River to receive a pro rata amount of shares of new Mirant

stock determined by Kern River's allowed claim amount plus interest in relation to the unsecured creditor class of over $6 billion. In February 2006, Kern River received an initial distribution of such shares in payment of the majority of its allowed claim. In June 2006, MidAmerican Funding sold a majority of the common shares it held in an electronic energy and metals trading exchange and realized a pre-tax gain of $27.6 million. MidAmerican Funding donated its remaining shares to a charitable foundation and recognized a pre-tax gain of $4.5 million as MidAmerican Funding's equity investment in the common shares was carried at zero cost.

Other expense for the second quarter and for the first six months of 2006 increased $5.8 million to $7.3 million and $3.8 million to $8.6 million, respectively, from the comparable periods in 2005. In connection with its disposition of common shares held in an electronic energy and metals trading exchange, MidAmerican Funding donated certain of these common shares to a charitable foundation and recognized a donation expense of $4.5 million.

Income Tax Expense

Income tax expense for the second quarter and for the first six months of 2006 increased $24.1 million to $81.7 million and $81.3 million to $212.9 million, respectively, from the comparable periods in 2005. The effective tax rate was 34.5% and 39.3%, respectively, for the second quarter of 2006 and 2005 and was 34.4% and 35.6%, respectively, for the first six months of 2006 and 2005. The lower effective tax rates in 2006 were mainly due to lower taxes on foreign sourced income and a lower effective tax rate at MidAmerican Funding due mainly to the effects of rate-making and production tax credits associated with wind generation, partially offset by higher tax accruals for uncertain tax positions.

Equity Income

Equity income for the second quarter and for the first six months of 2006 decreased $5.3 million to $7.9 million and $8.4 million to $9.7 million, respectively, from the comparable periods in 2005 due mainly to lower earnings at CE Generation resulting from more significant scheduled overhauls as well as lower equity income at HomeServices due to lower refinancing activity at its residential mortgage loan joint ventures.

Results of Operations – Fiscal Years 2005, 2004 and 2003

Consolidated Executive Summary

Operating results for the years ended December 31, 2005, 2004 and 2003 are summarized in the following table (in millions):

	Years Ended December 31,		
	2005	2004	2003
Operating revenue	$7,115.5	$6,553.4	$5,965.6
Operating income	$1,528.7	$1,525.4	$1,449.8
Interest expense	(891.0)	(903.2)	(761.0)
Other income, net	127.2	177.0	169.2
Income tax expense	(244.7)	(265.0)	(270.3)
Minority interest and preferred dividends of subsidiaries	(16.0)	(13.3)	(183.2)
Equity income	53.3	16.9	38.2
Income from continuing operations	557.5	537.8	442.7
Income (loss) from discontinued operations, net of tax	5.1	(367.6)	(27.1)
Net income available to common and preferred stockholders	$ 562.6	$ 170.2	$ 415.6

Table of Contents

In 2005, our income from continuing operations was $557.5 million versus $537.8 million in 2004. In 2005, we benefited from favorable comparative results at most of its domestic businesses and from gains on sales of certain non-strategic assets and investments. These improvements were partially offset by lower earnings from CE Electric UK, primarily associated with the distribution businesses. In the fourth quarter of 2004, we realized an after-tax gain of $43.7 million from the realization of certain Enron-related bankruptcy claims. Ignoring the effect of this one-time event, our income from continuing operations was $494.1 million, which, when compared to 2003 results, reflects improved results at most of our major operating platforms.

During the third quarter of 2004, we recorded an after-tax charge, which is reflected in discontinued operations, of $340.3 million to write down certain assets of the Zinc Recovery Project.

Segment Results

The reportable segment financial information includes all necessary adjustments and eliminations needed to conform to our 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, intersegment eliminations and fair value adjustments relating to acquisitions. Additionally, the activity of our Mineral Assets, which was previously reported in the CalEnergy Generation-Domestic reportable segment, is presented as discontinued operations within the consolidated financial statements included in the ‘‘Financial Statements’’ section of this prospectus.

A comparison of operating revenue and operating income for our reportable segments for the years ended December 31, 2005, 2004, and 2003 follows (in millions):

	Years Ended December 31,		
	2005	2004	2003
Operating revenue:			
MidAmerican Funding	$3,166.1	$2,701.7	$2,600.2
Kern River	323.6	316.1	260.2
Northern Natural Gas	569.1	544.8	486.9
CE Electric UK	884.1	936.4	830.0
CalEnergy Generation — Foreign	312.3	307.4	326.4
CalEnergy Generation — Domestic	33.8	39.0	45.2
HomeServices	1,868.5	1,756.4	1,476.6
Total reportable segments	7,157.5	6,601.8	6,025.5
Corporate/other	(42.0)	(48.4)	(59.9)
Total operating revenue	$7,115.5	$6,553.4	$5,965.6
Operating income:			
MidAmerican Funding	$ 381.1	$ 355.9	$ 367.9
Kern River	204.5	204.8	181.0
Northern Natural Gas	208.8	190.3	175.8
CE Electric UK	483.9	497.4	445.8
CalEnergy Generation — Foreign	185.0	188.5	197.5
CalEnergy Generation — Domestic	15.1	21.5	21.4
HomeServices	125.3	112.9	92.9
Total reportable segments	1,603.7	1,571.3	1,482.3
Corporate/other	(75.0)	(45.9)	(32.5)
Total operating income	$1,528.7	$1,525.4	$1,449.8

Table of Contents

MidAmerican Funding

MidAmerican Funding’s operating revenue and operating income for the years ended December 31, 2005, 2004, and 2003 are summarized as follows (in millions):

	Years Ended December 31,		
	2005	2004	2003
Operating revenue:			
Regulated electric	$1,513.2	$1,421.7	$1,398.0
Regulated gas	1,322.7	1,010.9	947.4
Nonregulated	330.2	269.1	254.8
Total operating revenue	$3,166.1	$2,701.7	$2,600.2
Operating income:			

	2005	2004	2003
Regulated electric	$ 334.9	$ 304.4	$ 307.8
Regulated gas	31.7	36.4	45.9
Nonregulated	14.5	15.1	14.2
Total operating income	$ 381.1	$ 355.9	$ 367.9

Regulated Electric Operations

The operating results of MidAmerican Energy's regulated electric business for the years ended December 31, 2005, 2004, and 2003 are summarized as follows (in millions, except for average number of customers):

	Years Ended December 31,		
	2005	**2004**	**2003**
Retail	$ 1,222.0	$ 1,136.7	$ 1,113.2
Wholesale	291.2	285.0	284.8
Total operating revenue	1,513.2	1,421.7	1,398.0
Cost of fuel, energy and capacity	468.1	398.6	396.3
Margin	1,045.1	1,023.1	1,001.7
Operating expense	472.9	483.5	444.4
Depreciation and amortization	237.3	235.2	249.5
Operating income	$ 334.9	$ 304.4	$ 307.8
Sales (gigawatt-hours):			
Retail	19,044	17,865	17,422
Wholesale	8,378	9,260	9,963
	27,422	27,125	27,385
Average number of customers	701,111	691,984	684,124

MidAmerican Energy's regulated electric retail revenue for 2005 increased $85.3 million, or 7.5%, to $1,222.0 million compared to 2004. Electric retail sales volumes increased 6.6% compared to 2004. Higher average temperatures during 2005 compared to 2004 resulted in a $43.4 million increase in electric retail revenue. A growing retail customer base in 2005 improved electric retail revenue by $17.7 million compared to 2004, while electricity usage factors not dependent on weather, such as the size of homes, technology changes and the use of multiple appliances, increased electric revenue by $9.1 million. Additionally, transmission revenue increased $7.9 million.

MidAmerican Energy's regulated electric retail revenue for 2004 increased $23.5 million, or 2.1%, to $1,136.7 million compared to 2003, and related sales volumes increased 2.5%. Electricity usage factors not dependent on weather, such as the size of homes, technology changes and the use of multiple appliances, improved electric revenue by $21.6 million compared to 2003, and an increase in

the average number of electric retail customers increased electric retail revenue by $20.7 million. Lower average temperatures during 2004 compared to 2003 resulted in a $26.9 million decrease in electric retail revenue.

In addition to retail sales, MidAmerican Energy sells electric energy to other utilities, marketers and municipalities. These sales are referred to as wholesale sales. MidAmerican Energy's wholesale revenue for 2005 increased $6.2 million, or 2.2%, to $291.2 million compared to 2004. The effect of higher electric energy prices, offset partially by a higher proportion of lower-priced, off-peak sales, increased wholesale energy revenue in 2005 by $33.3 million. Wholesale units for 2005 decreased 9.5% from 2004, resulting in a $27.1 million decrease in revenue. The primary reason for the decrease in wholesale sales volumes for 2005 was the timing of planned generation outages for the Louisa Generating Station and the loss of generating capacity at the Ottumwa Generating Station Unit No. 1 (or OGS Unit No. 1), which experienced a failure of its step-up transformer on February 20, 2005. OGS Unit No. 1 returned to service on May 3, 2005.

MidAmerican Energy's wholesale revenue for 2004 increased $0.2 million, or 0.1%, to $285.0 million compared to 2003. Wholesale energy revenue in 2004 increased by $20.3 million due to the impact of higher average wholesale prices. This was largely offset by a decrease in wholesale units of 7.1% from 2003, which resulted in a $20.1 million decrease in revenue.

Cost of fuel, energy and capacity for 2005 increased $69.5 million, or 17.4%, compared to 2004 due principally to the cost of replacement power in connection with the generating station outages previously discussed and the increased use of gas-fired generation, primarily from the Greater Des Moines Energy Center. Cost of fuel, energy and capacity for 2004 increased $2.3 million, or 0.6%, compared to 2003. The increase was principally due to the cost of replacement power as a result of generating stations taken out of service for preventive maintenance in 2004.

Regulated electric operating expense for 2005 decreased $10.6 million compared to 2004 due principally to the timing of generating plant maintenance and lower postretirement benefit costs, partially offset by higher distribution and transmission operations costs. Regulated electric operating expense for 2004 increased $39.1 million compared to 2003 due primarily to the timing of generating plant maintenance and increased generating plant operations expense. Additionally, electric distribution maintenance and operations expense and transmission operations expense were higher in 2004 compared to 2003.

Regulated electric depreciation and amortization expense for 2005 increased $2.1 million compared to 2004 as a result of an $11.1 million increase in electric utility plant depreciation and amortization due primarily to assets being placed in service, the most significant being the second phase of the Greater Des Moines Energy Center and 160.5 MW of wind power facilities in December 2004 and, to a lesser extent, an additional 200 MW of wind power facilities in late 2005. The increase in utility plant depreciation was partially offset by a $9.9 million decrease in regulatory expense pursuant to a revenue sharing arrangement with the state of Iowa due to lower Iowa electric equity returns. Regulated electric depreciation and amortization expense for 2004 decreased $14.3 million compared to 2003 due to a $9.8 million decrease related to the revenue sharing arrangements with the states of Illinois and Iowa. Additionally, electric utility plant depreciation and amortization decreased due in part to software assets that became fully depreciated in 2003.

Regulated Natural Gas Operations

Regulated natural gas revenue includes purchased gas adjustment clauses through which MidAmerican Energy is allowed to recover the cost of gas sold from its retail gas utility customers. Consequently, fluctuations in the cost of gas sold do not affect gross margin or operating income because revenues reflect comparable fluctuations through the purchased gas adjustment clauses. Compared to 2004, MidAmerican Energy's average per-unit cost of gas sold increased 32.8%, resulting in a $271.6 million increase in revenue and cost of gas sold for 2005. The remainder of the increase in cost of gas sold and gas revenue was primarily due to an increase in wholesale sales volumes. Additionally, an increase in the average number of retail customers contributed to the increase in gas revenue for 2005.

MidAmerican Energy's average per-unit cost of gas sold for 2004 increased 7.4%, resulting in a $54.3 million increase in revenue and cost of gas sold compared to 2003. The remainder of the increase in cost of gas sold and gas revenue was due to an increase in wholesale sales volumes. A decrease in gas retail sales volumes, in part due to milder temperature conditions in 2004 compared to 2003, reduced gas revenue for 2004. An increase in the average number of retail customers partially offset the decrease due to retail sales volumes.

Northern Natural Gas

Operating income for 2005 increased $18.5 million, or 9.7%, to $208.8 million from the comparable period in 2004. Northern Natural Gas recognized net benefits, due to the settlement of its consolidated rate case proceeding and its system levelized account (or SLA) settlement, to operating income during the year ended December 31, 2005 of $15.7 million reflecting final settlement adjustments and the ongoing operating impact of lower depreciation and amortization expense due to changes in the useful lives of its transmission, storage and intangible assets, partially offset by higher regulatory amortization of the remaining SLA balance.

Operating revenue for 2005 increased $24.3 million, or 4.5%, to $569.1 million from the comparable period in 2004. The increase was mainly due to higher gas and liquids sales of $25.6 million, due to higher sales of gas from operational storage utilized to manage physical flows on the pipeline system, and higher transportation and storage revenues of $8.3 million, due to changes in the composition of transportation contracts. These increases were partially offset by the net effects of the consolidated rate case and SLA settlements, which decreased operating revenue by $11.5 million.

Operating expenses for 2005 also increased $12.4 million from the comparable period in 2004 due to a $29.0 million long-lived asset impairment charge for West Hugoton recognized in the fourth quarter of 2005, partially offset by a gain of $19.7 million recognized in the second quarter of 2005 from the sale of an idled section of pipeline in Oklahoma and Texas. Northern Natural Gas entered into separate purchase and sale agreements (or PSA) relative to the West Hugoton and Beaver non-strategic sections of its interstate pipeline system in the fourth quarter of 2005. No impairment charge was needed for the Beaver pipeline as the sale price agreed to in the Beaver PSA exceeded the carrying value of the Beaver pipeline. The sales of the West Hugoton and Beaver assets are expected to close in late 2006.

Operating income for 2004 increased $14.5 million, or 8.2%, to $190.3 million from the comparable period in 2003. Northern Natural Gas' operating revenue for 2004, which reflects the effectuation of rate increases on November 1, 2004 and 2003, and higher gas and liquids sales, increased $57.9 million, or 11.9%, to $544.8 million from the comparable period in 2003. In 2004 and 2003, gas and liquids sales were subject to a regulatory tracking procedure and, therefore, any fluctuations in the amount of such sales had a corresponding effect on cost of sales. Depreciation and amortization for 2004 increased $15.2 million compared to 2003 due primarily to higher depreciation rates included in the filed rate cases.

Kern River

Operating income remained relatively flat in 2005 compared to 2004 and increased $23.8 million, or 13.1%, in 2004 compared to 2003. The increase in 2004 was primarily due to higher capacity reservation charges earned in connection with the May 2003 completion of a 717-mile expansion project (or the 2003 Expansion Project).

Operating revenue for 2005 increased $7.5 million, or 2.4%, to $323.6 million from the comparable period in 2004. The increase in operating revenue resulted from higher demand and commodity transportation revenues of $14.0 million due mainly to higher rates, subject to refund, for the current rate proceeding which became effective on November 1, 2004. This increase was partially offset by lower interruptible transportation revenue of $5.9 million. Operating revenue for 2004 increased $55.9 million, or 21.5%, to $316.1 million from the comparable period in 2003. The increase in operating revenue resulted primarily from higher demand and commodity transportation revenues, net of revenue sharing, of $52.2 million, associated with the full-year effect of higher capacity reservation charges on the additional capacity from the 2003 Expansion Project.

Depreciation and amortization expense for 2005 increased $9.1 million to $62.4 million from the comparable period in 2004 due to higher depreciation rates in connection with the current rate proceeding. Operating expenses and depreciation and amortization for 2004 increased $15.7 million, or 36.9%, and $16.5 million, or 44.8%, respectively, from the comparable period in 2003 due to the completion of the 2003 Expansion Project.

CE Electric UK

Operating income for 2005 decreased $13.5 million, or 2.7%, to $483.9 million compared with 2004. Operating revenue for 2005 decreased $52.3 million, or 5.6%, to $884.1 million compared with 2004 due primarily to $37.0 million of lower distribution revenues, $9.1 million of lower contracting revenues and a $6.9 million adverse impact of the exchange rate. Cost of sales for 2005 decreased $7.5 million due mainly to lower contracting work and exit charges from the National Grid Company. Operating expenses for 2005 decreased $29.4 million due mainly to $13.3 million of gains recognized on the partial disposal of certain CE Gas Australian assets and lower costs of $11.2 million associated with the withdrawal from the metering market.

Operating income for 2004 increased $51.6 million, or 11.6%, to $497.4 million compared with 2003. Operating revenue for 2004 increased $106.4 million, or 12.8%, to $936.4 million compared with 2003 due primarily as a result of the weaker U.S. dollar and increased contracting revenue. Cost of sales for 2004 increased $16.7 million mainly due to increased contracting activity and the weaker U.S. dollar, partially offset by lower exit charges from the National Grid Company at both Northern Electric and Yorkshire Electricity. Operating expenses for 2004 increased $16.5 million due to higher pension costs and the weaker U.S. dollar in 2004, and a gain on the sale of a local operational dispatch facility in 2003. Depreciation and amortization for 2004 increased $12.7 million primarily due to the weaker U.S. dollar.

CalEnergy Generation-Foreign

Operating income for 2005 decreased $3.5 million, or 1.9%, to $185.0 million compared with 2004. Operating revenue for 2005 increased $4.9 million, or 1.6%, to $312.3 million compared with 2004. The increase in operating revenue was mainly due to higher capacity prices at the Leyte Projects and higher water delivery fees at the Casecnan Project pursuant to contractual escalation factors.

Operating income for 2004 decreased $9.0 million, or 4.6%, to $188.5 million compared with 2003. Operating revenue for 2004 decreased $19.0 million, or 5.8%, to $307.4 million compared with 2003. Each decrease was primarily due to lower water delivery fees in 2004 resulting from the NIA arbitration settlement at CE Casecnan, partially offset by higher contractually-specified capacity and water delivery prices in 2004 and by the reversal of accrued revenue in connection with the settlement of various disputes between the Leyte Projects and the Philippine National Oil Company-Energy Development Corporation (or PNOC-EDC) in 2003.

HomeServices

Operating income for 2005 increased $12.4 million, or 11.0%, to $125.3 million from the comparable period in 2004. Operating revenue for 2005 increased $112.1 million, or 6.4%, to $1,868.5 million and cost of sales increased $78.2 million from the comparable period in 2004. The increase in operating revenue was due to growth from existing businesses totaling $62.1 million reflecting primarily higher average sales prices and acquisitions not included in the comparable 2004 period totaling $49.4 million.

Operating expenses for 2005 increased $24.5 million from the comparable period in 2004 mainly due to $12.8 million related to acquisitions not included in the comparable 2004 period and $11.7 million in higher operating expense at existing businesses due primarily to higher marketing and occupancy expenses. Depreciation and amortization for 2005 was $3.1 million lower than the comparable period in 2004 due primarily to lower amortization of acquisition related costs in 2005 as compared to the same period in 2004.

Table of Contents

Operating income for 2004 increased $20.0 million, or 21.5%, to $112.9 million from the comparable period in 2003. Operating revenue for 2004 increased $279.8 million, or 18.9%, to $1,756.4 million and cost of sales increased $211.8 million from the comparable period in 2003. The increase in operating revenue was due to growth from existing businesses totaling $154.7 million reflecting primarily higher average sales prices and acquisitions not included in the comparable 2003 period totaling $125.1 million.

Operating expenses for 2004 increased $44.8 million from the comparable period in 2003 mainly due to $27.8 million related to acquisitions not included in the comparable 2003 period and $17.0 million in higher operating expense at existing businesses due primarily to higher salaries and employee benefits, marketing and occupancy expenses. Depreciation and amortization for 2004 was $3.3 million higher than the comparable period in 2003 due primarily to higher amortization of acquisition related costs in 2004 as compared to the same period in 2003.

Consolidated Other Income and Expense Items

Interest Expense

Interest expense for the years ended December 31, 2005, 2004 and 2003 is summarized as follows (in millions):

	Years Ended December 31,		
	2005	**2004**	**2003**
Subsidiary short-term and long-term debt	$533.3	$521.5	$522.1
Parent company short-term and senior debt	173.2	184.8	189.1
Parent company subordinated debt-Berkshire	157.3	169.9	43.1
Parent company subordinated debt-other	27.2	27.0	6.7
Total interest expense	$891.0	$903.2	$761.0

Interest expense on subsidiary short-term and long-term debt for 2005 increased $11.8 million to $533.3 million from $521.5 million for the same period in 2004 due mainly to a $10.2 million charge incurred in the first quarter of 2005 to exercise the call option on the £155.0 million Variable Rate Reset Trust Securities at CE Electric UK, as well as due to additional interest expense on the £350.0 million of 5.125% bonds issued by certain indirect wholly owned subsidiaries of CE Electric UK in May 2005 and MidAmerican Energy’s 4.65%, $350.0 million notes issued in October 2004 and 5.75%, $300.0 million notes issued in November 2005. These increases were partially offset by lower interest expense due to maturities of and principal repayments on subsidiary and project debt.

Interest expense on subsidiary short-term and long-term debt for 2004 decreased $0.6 million to $521.5 million from $522.1 million for the same period in 2003 due to lower interest expense due to the redemption in full of the outstanding shares of the Yorkshire Capital Trust I, 8.08% trust securities in June 2003 and reductions in subsidiary and project debt. These decreases were largely offset by higher interest expense due to the effects of the weaker U.S. dollar.

Interest expense on parent company short-term and senior debt for 2005 decreased $11.6 million to $173.2 million from $184.8 million for the same period in 2004 due primarily to our scheduled redemption of $260.0 million of 7.23% senior notes in September 2005. Interest expense on parent company short-term and senior debt for 2004 decreased $4.3 million to $184.8 million from $189.1 million for the same period in 2003 due primarily to our scheduled redemption of $215.0 million of 6.96% senior notes in September 2003. This decrease was partially offset by higher interest expense on our debt issuances of $450.0 million of 3.5% senior notes in May 2003 and $250.0 million of 5.0% senior notes in February 2004.

Interest expense on parent company subordinated debt-Berkshire for 2005 decreased $12.6 million to $157.3 million from $169.9 million for the same period in 2004 due primarily to scheduled principal repayments. Interest expense on parent company subordinated debt for 2004

increased $147.1 million to $196.9 million from $49.8 million for the same period in 2003. On October 1, 2003, we adopted FIN 46R related to certain finance subsidiaries. The adoption required that amounts previously recorded in minority interest and preferred dividends of subsidiaries be recorded prospectively as interest expense in the accompanying consolidated statement of operations. In accordance with the requirements of FIN 46R, no amounts prior to adoption on October 1, 2003 were reclassified. The amount included in minority interest and preferred dividends of subsidiaries related to these finance subsidiaries for the nine-month period ended September 30, 2003, was $170.2 million. The increase due to the adoption of FIN 46R was partially offset by lower interest expense due to scheduled principal repayments.

Other Income, Net

Other income, net for the years ended December 31, 2005, 2004, and 2003 is summarized as follows (in millions):

	Years Ended December 31,		
	2005	**2004**	**2003**
Capitalized interest	$ 16.7	$ 20.0	$ 30.5
Interest and dividend income	58.1	38.9	47.9
Other income	74.5	128.2	96.7
Other expense	(22.1)	(10.1)	(5.9)
Total other income, net	$127.2	$177.0	$169.2

Capitalized interest for 2005 decreased due to lower capitalization at Northern Electric and Yorkshire Electricity, partially offset by higher capitalized interest at MidAmerican Energy associated with an increase in the construction of generation facilities. Capitalized interest for 2004 decreased $10.5 million to $20.0 million from $30.5 million for the same period in 2003. Kern River capitalized $17.2 million of interest in 2003 related to its 2003 Expansion Project. This was partially offset by increased construction activity at MidAmerican Energy's generation projects.

Interest and dividend income for 2005 increased $19.2 million to $58.1 million from $38.9 million for the same period in 2004 mainly due to earnings on guaranteed investment contracts (£100.0 million at 4.75% and £200.0 million at 4.73%) purchased by certain indirect wholly owned subsidiaries of CE Electric UK in May 2005 as well as earnings on higher cash balances and higher short-term interest rates.

Interest and dividend income for 2004 decreased $9.0 million to $38.9 million from $47.9 million for the same period in 2003. The decrease was mainly due to dividend income received in 2003 from our investment in Williams Cumulative Convertible Preferred Stock that was sold in June 2003, partially offset by higher interest income at CE Electric UK resulting from higher cash balances.

Other income for 2005 decreased $53.7 million from the comparable period in 2004, which increased $31.5 million from the comparable period in 2003. In 2005, we realized gains from sales of certain non-strategic investments at MidAmerican Funding of $13.4 million and CE Electric UK of $8.4 million. In 2004, we recognized a $72.2 million gain on Northern Natural Gas' sale of an approximately $259 million note receivable with Enron (or the Enron Note Receivable) and a $14.8 million gain on amounts collected by Kern River on its claim for damages against Mirant. In 2003, we recognized a $31.9 million gain in connection with the NIA arbitration settlement and a $13.8 million gain on the sale of Williams Cumulative Convertible Preferred Stock. Additionally, the allowance for equity funds used during construction for 2005 increased $5.7 million compared to 2004 due to increased levels of capital project expenditures at MidAmerican Energy, while the allowance for equity funds used during construction for 2004 decreased $6.2 million compared to 2003 due primarily to the completion of Kern River's 2003 Expansion Project in May 2003.

Included in other expense for 2005 are losses for other-than-temporary impairments of MidAmerican Funding's investments in commercial passenger aircraft leased to major domestic airlines, which are accounted for as leveraged leases, of $15.8 million. These impairments result from

MidAmerican Funding's evaluation of these investments in light of the continued deterioration of the airline industry and the bankruptcy filings of two major airline carriers during 2005. The remaining carrying values of MidAmerican Funding's commercial aircraft leveraged leases are not material.

Income Tax Expense

Income tax expense for 2005 decreased $20.3 million to $244.7 million from $265.0 million for the same period in 2004. The effective tax rate was 32.0% and 33.2% for 2005 and 2004, respectively. The lower effective tax rate in 2005 was mainly due to the effects of production tax credits related to energy produced by MidAmerican Energy's wind facilities, the first of which were placed in service on December 31, 2004, and lower income taxes on foreign earnings in 2005, partially offset by a change in the state of Iowa's income tax laws in 2004 related to bonus depreciation that lowered income tax expense and benefits from CE Electric UK's settlement of various positions with the Inland Revenue department.

Income tax expense for 2004 decreased $5.3 million to $265.0 million from $270.3 million for the same period in 2003. The effective tax rate was 33.2% and 31.5% for 2004 and 2003, respectively. The increase in the effective tax rate in 2004 was mainly due to the effect of the $170.2 million of tax deductible interest on subordinated debt not included in income from continuing operations before income tax expense, minority interest and preferred dividends of subsidiaries and equity income in 2003, partially offset by the $24.4 million tax payment made in connection with the NIA arbitration settlement at CE Casecnan in 2003, CE Electric UK's settlement of various positions with the Inland Revenue department and a change in the state of Iowa's income tax laws in 2004 related to bonus depreciation that lowered income tax expense.

Equity Income

Equity income for 2005 increased $36.4 million to $53.3 million compared with $16.9 million for the same period in 2004. The increase was mainly due to higher earnings at CE Generation due to higher energy rates, partially offset by higher fuel costs, mainly at its natural gas-fired generation facilities and increased production at the Imperial Valley Projects due to the timing and length of scheduled outages and lower major maintenance costs, partially offset by higher fuel costs. Additionally, 2004 results included MEHC's $16.8 million after-tax portion of a charge as a result of the partial impairment of the carrying value of CE Generation's Power Resources project.

Equity income for 2004 decreased $21.4 million to $16.9 million compared with $38.3 million for the same period in 2003, mainly due to MEHC's $16.8 million after-tax portion of the Power Resources project impairment. Additionally, HomeServices' mortgage joint ventures had lower income due to lower refinancing activity.

Discontinued Operations

On September 10, 2004, management made the decision to cease operations of the Zinc Recovery Project. In connection with ceasing operations, the Zinc Recovery Project's assets have been dismantled and sold and certain employees of the operator of the Zinc Recovery Project were paid one-time termination benefits. Implementation of the decommissioning plan began in September 2004 and, as of December 31, 2005, the dismantling, decommissioning, and sale of remaining assets of the Zinc Recovery Project was completed.

The income from discontinued operations, net of income tax, of $5.1 million for the year ended December 31, 2005 reflects the proceeds received from the sale of assets, partially offset by the disposal costs incurred, in connection with the September 2004 decision to cease the operations of the Zinc Recovery Project. The loss from discontinued operations, net of income tax, of $367.6 million for the year ended December 31, 2004 consists primarily of a $340.3 million impairment charge recognized in connection with ceasing the operations of the Zinc Recovery Project. The $27.1 million loss from discontinued operations, net of income tax, for the year ended December 31, 2003 reflects losses incurred from operating the Zinc Recovery Project.

Liquidity and Capital Resources

We have available a variety of sources of liquidity and capital resources, both internal and external, including the Berkshire Equity Commitment. These resources provide funds required for current operations, construction expenditures, debt retirement and other capital requirements. We may from time to time seek to retire our outstanding securities through cash purchases in the open market, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Each of our direct and indirect subsidiaries is organized as a legal entity separate and apart from us and our other subsidiaries. Pursuant to separate financing agreements at each subsidiary, the assets of each subsidiary may be pledged or encumbered to support or otherwise provide the security for its own project or subsidiary debt. It should not be assumed that any asset of any subsidiary of ours will be available to satisfy our obligations or any of our other subsidiaries' obligations, and we have made certain regulatory commitments limiting our ability to do so; provided, however, that unrestricted cash or other assets which are available for distribution may, subject to applicable law and the terms of financing and ring-fencing arrangements for such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to us or affiliates thereof.

Our cash and cash equivalents and short-term investments, which consist primarily of auction-rate securities that are used in our cash management program, were $413.0 million at June 30, 2006, compared to $396.3 million and $960.9 million at December 31, 2005 and 2004, respectively. In addition, we recorded separately, in restricted cash and short-term investments and in deferred charges and other assets, restricted cash and investments of $129.8 million, $136.7 million and $164.5 million at June 30, 2006, December 31, 2005 and December 31, 2004, respectively. The restricted cash balance is mainly composed of amounts deposited in restricted accounts relating to (i) our debt service reserve requirements relating to certain projects, (ii) customer deposits held in escrow, (iii) custody deposits, and (iv) unpaid dividends declared obligations. The debt service funds are restricted by their respective project debt agreements to be used only for the related project.

Cash Flows from Operating Activities

We generated cash flows from operations of $952.9 million for the first six months of 2006, compared with $861.1 million from the comparable period in 2005. The increase was mainly due to better cash flow at MidAmerican Funding due to higher electric wholesale results, the greater utilization of income tax net operating loss carryforwards and the inclusion of PacifiCorp's operating cash flows for the period from acquisition to June 30, 2006, partially offset by lower period over period cash flow at CE Electric UK due mainly to a tax refund received in 2005.

We generated cash flows from operations of $1,310.8 million for the year ended December 31, 2005, compared with $1,424.6 million for the same period in 2004. The decrease was mainly due to the receipt of a $79.0 million federal tax refund in 2004, related to additional tax depreciation, partially offset by higher earnings, changes in other working capital and a $33.6 million reduction in 2005 of cash used at the Zinc Recovery Project's discontinued operations.

Cash Flows from Investing Activities

Cash flows used in investing activities for the first six months of 2006 and 2005 were $5,790.3 million and $972.9 million, respectively. The increase was primarily due to the 2006 acquisition of PacifiCorp, net of cash acquired, the 2005 purchase, with the majority of the proceeds of the issuance of £350.0 million of 5.125% bonds due in 2035, of two guaranteed investment contracts by certain indirect wholly owned subsidiaries of CE Electric UK totaling $556.6 million, and a $408.7 million increase in capital expenditures, construction and other development costs. Additionally, Kern River received proceeds in 2006 totaling $89.3 million from the sale of Mirant shares received in payment of the majority of its allowed bankruptcy claim and MidAmerican Funding received proceeds in 2006 totaling $27.6 million from the sale of common shares held in an electronic energy and metals trading exchange.

Cash flows used in investing activities for the years ended December 31, 2005 and 2004 were $1,551.3 million and $1,098.1 million, respectively. The increase was mainly due to the purchase, with

the majority of the proceeds of the issuance of £350.0 million of 5.125% bonds due in 2035, of two guaranteed investment contracts by certain indirect wholly owned subsidiaries of CE Electric UK totaling $556.6 million and the collection of the $97.0 million ROP Note and $72.2 million from the Enron Note Receivable in 2004, partially offset by higher proceeds from sale of non-strategic investments and assets in 2005 totaling $94.2 million.

PacifiCorp Acquisition

On March 21, 2006, a wholly owned subsidiary of ours acquired 100% of the common stock of PacifiCorp from a wholly owned subsidiary of ScottishPower for a cash purchase price of $5,109.5 million, which was funded through the issuance of common stock. We also incurred $10.2 million of direct transaction costs associated with the acquisition, which consisted principally of investment banker commissions and outside legal and accounting fees and expenses, resulting in a total purchase price of $5,119.7 million. The results of PacifiCorp's operations are included in our results beginning March 21, 2006.

In January through March 2006, the state commissions in all six states where PacifiCorp has retail customers approved the sale of PacifiCorp to us. The approvals were conditioned on a number of regulatory commitments, including expected financial benefits in the form of reduced corporate overhead and financing costs, certain mid− to long-term capital and other expenditures of significant amounts and a commitment not to seek utility rate increases attributable solely to the change in ownership. The capital and other expenditures proposed by us and PacifiCorp include:

- Approximately $812 million in investments (generally to be made over several years following the sale and subject to subsequent regulatory review and approval) in emissions reduction technology for PacifiCorp's existing coal plants, which, when coupled with the use of reduced emissions technology for anticipated new coal-fueled generation, is expected to result in significant reductions in emissions rates of SO_2, NO_x and mercury and to avoid an increase in the carbon dioxide emissions rate;
- Approximately $520 million in investments (to be made over several years following the sale and subject to subsequent regulatory review and approval) in PacifiCorp's transmission and distribution system that would enhance reliability, facilitate the receipt of renewable resources and enable further system optimization; and
- The addition of 400 MW of cost-effective renewable resources to PacifiCorp's generation portfolio by December 31, 2007, including 100 MW of cost-effective wind resources by March 21, 2007.

The commitments approved by the state commissions also include credits that will reduce retail rates generally through 2010 to the extent that PacifiCorp does not achieve identified cost reductions or demonstrate mitigation of certain risks to customers. The maximum potential value of these rate credits to customers in all six states is $142.5 million.

Capital Expenditures, Construction and Other Development Costs

Capital expenditures, construction and other development costs for the first six months of 2006 and 2005 and for the years ended December 31, 2005 and 2004 are summarized by reportable segment as follows (in millions):

	Six Months Ended June 30,		Years Ended December 31,	
	2006	**2005**	**2005**	**2004**
Capital expenditures:				
PacifiCorp	$353.4	$ —	$ —	$ —
MidAmerican Energy	323.5	331.9	701.0	633.8
Northern Natural Gas	39.3	30.6	124.7	138.8

CE Electric UK	188.3	138.9	342.6	334.5
Other reportable segments and corporate/other	13.0	7.4	27.9	72.3
Total capital expenditures	$917.5	$508.8	$1,196.2	$1,179.4

Forecasted capital expenditures, construction and other development costs for fiscal 2006 are approximately $2.4 billion. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of such reviews. Estimates of environmental capital and operating requirements may change significantly at any time as a result of, among other factors, changes in related regulations, prices of products used to meet the requirements, competition in the industry for similar technology and management's strategies for achieving compliance with the regulations. We expect to meet these capital expenditures with cash flows from operations and the issuance of debt. Capital expenditures relating to operating projects, consisting mainly of recurring expenditures and the funding of growing load requirements, were $698.2 million for the first six months of 2006. Construction and other development costs were $219.3 million for the first six months of 2006. Capital expenditures relating to operating projects, consisting of recurring expenditures and the funding of growing load requirements, were $796.3 million for the year ended December 31, 2005. Construction and other development costs were $399.9 million for the year ended December 31, 2005. These costs consist mainly of expenditures for large scale generation projects at PacifiCorp and MidAmerican Energy as described below.

PacifiCorp

In March 2006, PacifiCorp completed construction of the Currant Creek Power Plant, a 523-MW combined-cycle plant in Utah. Total project costs incurred through June 30, 2006 were approximately $339 million. Presently under construction is the Lake Side Power Plant, an estimated 550-MW combined-cycle plant in Utah, expected to be in service by the summer of 2007. The cost of the Lake Side Power Plant is expected to total approximately $347 million, of which approximately $251 million has been incurred through June 30, 2006. Both plants are 100% owned and operated by PacifiCorp.

In July 2006, PacifiCorp entered into an agreement to acquire a 100.5-MW (nameplate rating) wind-powered generation facility that is currently under construction and expected to begin commercial operation in the third quarter of 2006.

Additionally, in conjunction with regulatory commitments made by us, approximately $520 million in investments are anticipated being made to PacifiCorp's transmission and distribution system over the next several years that would enhance reliability, facilitate the receipt of renewable resources and enable further system optimization. Such investments would be subject to regulatory review and approval.

PacifiCorp's capital requirements for the period from acquisition to December 31, 2006 are estimated to be approximately $1,036 million, which includes $321 million for the generation development projects described above, $102 million for emissions control equipment to address current and anticipated air quality regulations and $613 million for ongoing operational projects, including connections for new customers and facilities to accommodate load growth. In addition to capital expenditure requirements, incremental operating costs are expected to be incurred by PacifiCorp in conjunction with the utilization of the emission control equipment.

In conjunction with state regulatory approvals of our acquisition of PacifiCorp, we and PacifiCorp committed to invest approximately $812 million, which include the $102 million planned for the period from acquisition to December 31, 2006, in capital spending over several years for emission control equipment to address current and future air quality initiatives implemented by the EPA or the states in which PacifiCorp operates facilities. Additional capital expenditures for emission reduction projects may be required, depending on the outcome of pending or new air quality regulations.

MidAmerican Funding

MidAmerican Energy anticipates a continuing increase in demand for electricity from its regulated customers. To meet anticipated demand and ensure adequate electric generation in its service territory, MidAmerican Energy is currently constructing CBEC Unit 4, a 790-MW (expected accreditation) super-critical-temperature, coal-fired generating plant. MidAmerican Energy will operate the plant and hold an undivided ownership interest as a tenant in common with the other

owners of the plant. MidAmerican Energy's current ownership interest is 60.67%, equating to 479 MW of output. Municipal, cooperative and public power utilities will own the remainder, which is a typical ownership arrangement for large base-load plants in Iowa. MidAmerican Energy expects to invest approximately $737 million in CBEC Unit 4, including transmission facilities and excluding allowance for funds used during construction. Through June 30, 2006, MidAmerican Energy has invested $594.0 million in the project, including $121.3 million for MidAmerican Energy's share of deferred payments allowed by the construction contract.

On December 16, 2005, MidAmerican Energy filed with the IUB a settlement agreement between MidAmerican Energy and the Iowa Office of Consumer Advocate (or OCA) regarding ratemaking principles for up to 545 MW (nameplate ratings) of wind-powered generation capacity in Iowa to be installed in 2006 and 2007. Generally speaking, accredited capacity ratings for wind power facilities are considerably less than the nameplate ratings due to the varying nature of wind. The settlement agreement was approved by the IUB on April 18, 2006. MidAmerican Energy has entered into agreements for the construction of approximately 99 MW (nameplate ratings) of wind-powered generation capacity to be completed by the end of 2006 and for the construction of approximately 123 MW (nameplate ratings) of wind-powered generation capacity to be completed by the end of 2007. The second agreement also provides for the sale of development rights to an adjacent project whose size could be up to 77 MW (nameplate ratings).

MidAmerican Energy's capital requirements for 2006 are estimated to be approximately $799 million, which includes $422 million for the generation development projects described above, $61 million for emissions control equipment to address current and anticipated air quality regulations and $316 million for ongoing operational projects, including connections for new customers and facilities to accommodate load growth. In addition to capital expenditure requirements, incremental operating costs are expected to be incurred by MidAmerican Energy in conjunction with the utilization of the emission control equipment.

MidAmerican Energy has implemented a planning process that forecasts the site-specific controls and actions that may be required to meet air emissions reductions as promulgated by the EPA. The plan allows MidAmerican Energy to more effectively manage its expenditures required to comply with emissions standards. On April 1, 2006, MidAmerican Energy submitted to the IUB an updated plan, as required every two years by Iowa law, which increased its estimate of required expenditures. MidAmerican Energy currently estimates that the incremental capital expenditures for emission control equipment to comply with air quality requirements will total approximately $540 million for January 1, 2006, through December 31, 2015.

Put of ROP Note and Receipt of Cash

On January 14, 2004, CE Casecnan exercised its right to put the ROP Note to the ROP and, in accordance with the terms of the put option, CE Casecnan received $99.2 million (representing $97.0 million par value plus accrued interest) from the ROP on January 21, 2004.

Sale of Enron Note Receivable and Receipt of Cash

Northern Natural Gas had a note receivable of approximately $259.0 million (or the Enron Note Receivable) with Enron. As a result of Enron filing for bankruptcy on December 2, 2001, Northern Natural Gas filed a bankruptcy claim against Enron seeking to recover payment of the Enron Note Receivable. As of December 31, 2001, Northern Natural Gas had written off the note. By stipulation, Enron and Northern Natural Gas agreed to a value of $249.0 million for the claim and received approval of the stipulation from Enron’s Bankruptcy Court on August 26, 2004. On November 23, 2004, Northern Natural Gas sold its stipulated general, unsecured claim against Enron of $249.0 million to a third party investor for $72.2 million, which was recorded as other income in the fourth quarter of 2004.

Cash Flows from Financing Activities

Net cash flows generated from financing activities for the first six months of 2006 were $4,871.8 million. Sources of cash totaled $7,000.8 million and consisted mainly of $5,122.6 million of

---

proceeds from the issuance of common stock and $1,699.3 million of proceeds from the issuance of parent company senior debt. Uses of cash totaled $2,129.0 million and consisted mainly of $1,750.0 million for repurchases of common stock and $245.3 million for repayments of subsidiary and project debt.

Net cash flows generated from financing activities for the first six months of 2005 were $117.9 million. Sources of cash totaled $753.5 million and consisted primarily of $752.1 million of proceeds from the issuance of subsidiary and project debt. Uses of cash totaled $635.6 million and consisted primarily of $606.5 million for repayments of subsidiary and project debt.

Net cash flows used in financing activities for the year ended December 31, 2005 were $219.1 million. Uses of cash totaled $1,331.2 million and consisted primarily of $875.4 million for repayments of subsidiary and project debt and $448.5 million for repayments of parent company senior and subordinated debt. Sources of cash totaled $1,112.1 million and consisted of $1,050.6 million of proceeds from the issuance of subsidiary and project debt and $51.0 million of net proceeds from our parent company revolving credit facility.

Net cash flows used in financing activities for the year ended December 31, 2004 were $105.4 million. Uses of cash totaled $730.5 million and consisted mainly of $504.8 million for repayments of subsidiary and project debt, including $136.4 million of cash flows from discontinued operations, $100.0 million for repayments of parent company subordinated debt and $43.9 million of net repayments of subsidiary short-term debt. Sources of cash totaled $625.1 million and consisted of $375.3 million of proceeds from the issuance of subsidiary and project debt and $249.8 million of proceeds from the issuance of parent company senior debt.

2006 Stock Transactions and Agreements

On March 1, 2006, we and Berkshire Hathaway entered into the Berkshire Equity Commitment pursuant to which Berkshire Hathaway has agreed to purchase up to $3.5 billion of our common equity upon any requests authorized from time to time by our Board of Directors. The proceeds of any such equity contribution shall only be used for the purpose of (a) paying when due our debt obligations and (b) funding the general corporate purposes and capital requirements of our regulated subsidiaries. Berkshire Hathaway will have up to 180 days to fund any such request. The Berkshire Equity Commitment will expire on February 28, 2011, was not used for the PacifiCorp acquisition and will not be used for future acquisitions.

On March 6, 2006, Mr. David L. Sokol, our Chairman and Chief Executive Officer, exercised 450,000 common stock options having an exercise price of $29.01 per share. Additionally, Mr. Sokol put 344,274 shares of common stock to us for a purchase price of $50.0 million.

On March 21, 2006, Berkshire Hathaway and certain other of our existing stockholders and related companies invested $5,109.5 million, in the aggregate, in 35,237,931 shares of our common stock in order to provide equity funding for the PacifiCorp acquisition. The per-share value assigned to the shares of common stock issued, which were effected pursuant to a private placement and were exempt from the registration requirements of the Securities Act of 1933, as amended, was based on an assumed fair market value as agreed to by our stockholders.

On March 28, 2006, we repurchased 11,724,138 shares of our common stock from Berkshire Hathaway for an aggregate purchase price of $1,700.0 million.

2006 Debt Issuances, Redemptions and Maturities

In addition to the debt issuances, redemption and maturities discussed herein, we and our subsidiaries made scheduled repayments on parent company subordinated debt and subsidiary and project debt totaling approximately $312 million during the six-month period ended June 30, 2006.

- On March 24, 2006, we completed the $1,700.0 million offering of the initial 2006 bonds. The initial 2006 bonds were issued at an offering price of 99.957%, will accrue interest at a rate of

6.125% per annum and will mature on April 1, 2036. Accrued interest on the initial 2006 bonds is payable on April 1 and October 1 of each year, commencing on October 1, 2006, until the principal amount of the initial 2006 bonds is paid in full. The proceeds were used to fund our exercise of our right to purchase shares of our common stock previously issued to Berkshire Hathaway.

- On June 15, 2006, MidAmerican Energy's 6.375% series of notes, totaling $160.0 million, matured.
- On August 10, 2006, PacifiCorp issued $350.0 million of 6.10%, 30-year first mortgage bonds. The proceeds from this offering are being used to repay a portion of PacifiCorp's short-term debt and for general corporate purposes.

2005 Debt Issuances, Redemptions and Maturities

In addition to the debt issuances, redemption and maturities discussed herein, we and our subsidiaries made scheduled repayments on parent company subordinated debt and subsidiary and project debt totaling approximately $565 million during the year ended December 31, 2005.

- In February 2005, a subsidiary of CE Electric UK exercised a call option to purchase, and then cancelled, its £155.0 million Variable Rate Reset Trust Securities, due in 2020. A charge to exercise the call option of $10.2 million was recognized in interest expense.
- On February 15, 2005, MidAmerican Energy's 7% series of mortgage bonds, totaling $90.5 million, were repaid upon maturity.
- On April 14, 2005, Northern Natural Gas issued $100.0 million of 5.125% senior notes due May 1, 2015. The proceeds were used by Northern Natural Gas to repay its outstanding $100.0 million 6.875% senior notes due May 1, 2005.
- On May 5, 2005, Northern Electric Finance plc, an indirect wholly owned subsidiary of CE Electric UK, issued £150.0 million of 5.125% bonds due 2035, guaranteed by Northern Electric and guaranteed as to scheduled payments of principal and interest by Ambac. Additionally, on May 5, 2005, Yorkshire Electricity, a wholly owned subsidiary of CE Electric UK, issued £200.0 million of 5.125% bonds due 2035, guaranteed as to scheduled payments of principal and interest by Ambac. The proceeds from the offerings are being invested and used for general corporate purposes. Investments include a £100.0 million, 4.75%, fixed-rate guaranteed investment contract maturing in December 2007 and a £200.0 million, 4.73%, fixed-rate guaranteed investment contract maturing in February 2008. The proceeds from the maturing guaranteed investment contracts will be used to repay certain long-term debt of subsidiaries of CE Electric UK. In connection with the issuance of such bonds, CE Electric UK entered into agreements amending certain terms and conditions of its £200.0 million 7.25% bonds due 2022.
- On September 15, 2005, our 7.23% senior notes, totaling $260.0 million, were repaid upon maturity.
- On November 1, 2005, MidAmerican Energy issued $300.0 million of 5.75% medium-term notes due in 2035. The proceeds are being used to support construction of its electric generation projects and for general corporate purposes.

CalEnergy Generation-Foreign – Customers

The PNOC-EDC's and the NIA's obligations under the project agreements are substantially denominated in U.S. Dollars and are the Leyte Projects' and the Casecnan Project'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 agreements and any material failure of the Republic of the Philippines 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.

The 10-year cooperation period for the Upper Mahiao Project ended on June 25, 2006, and the Upper Mahiao Project was transferred to the PNOC-EDC at no cost on an ''as-is'' basis. Additionally, the 10-year cooperation periods for the Mahanagdong and Malitbog Projects end in July 2007, at which time each project will also be transferred to the PNOC-EDC at no cost on an ''as-is'' basis. For the first six months of 2006, the Upper Mahiao Project's financial results represented 0.5%, 1.1% and 1.6%, respectively, and the Mahanagdong and Malitbog Projects' combined financial results represented 1.6%, 5.5% and 5.1%, respectively, of our total consolidated operating revenue, income from continuing operations and operating cash flows from continuing operations. Additionally, the net properties, plants and equipment and the project debt of the Mahanagdong and Malitbog Projects represented less than 1%, respectively, of our total consolidated net properties, plants and equipment and subsidiary and project debt at June 30, 2006.

Credit Ratings Risks

Debt and preferred securities of ours and our subsidiaries may be rated by nationally recognized 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 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. Other than the agreements discussed below, we and our subsidiaries do not have any credit agreements that require termination or a material change in collateral requirements or payment schedule in the event of a downgrade in the credit ratings of the respective company's securities.

In conjunction with its risk management activities, PacifiCorp and MidAmerican Energy must meet credit quality standards as required by counterparties. In accordance with industry practice, master agreements that govern PacifiCorp's and MidAmerican Energy's energy supply and marketing activities either specifically require each company to maintain investment-grade credit ratings or provide the right for counterparties to demand ‘‘adequate assurances’’ in the event of a material adverse change in PacifiCorp's or MidAmerican Energy's creditworthiness. If one or more of PacifiCorp's or MidAmerican Energy's credit ratings decline below investment grade, PacifiCorp or MidAmerican Energy may be required to post cash collateral, letters of credit or other similar credit support to facilitate ongoing wholesale energy supply and marketing activities. As of June 30, 2006, PacifiCorp's and MidAmerican Energy's credit ratings from the three recognized credit rating agencies were investment grade; however if the ratings fell below investment grade, PacifiCorp's and MidAmerican Energy's estimated potential collateral requirements totaled approximately $204 million and $144 million, respectively. PacifiCorp's and MidAmerican Energy's potential collateral requirements could fluctuate considerably due to seasonality, market price volatility, and a loss of key generating facilities or other related factors.

Yorkshire Power Group Limited (or YPGL), a subsidiary of CE Electric UK, has in effect certain currency rate swap agreements for its Yankee bonds with three large multi-national financial institutions. The swap agreements effectively convert the U.S. dollar fixed interest rate to a fixed rate in sterling for $281.0 million of 6.496% Yankee bonds outstanding at June 30, 2006. The agreements extend until February 25, 2008 and convert the U.S. dollar interest rate to a fixed sterling rate ranging from 7.3175% to 7.3450%. The estimated fair value of these swap agreements at June 30, 2006, was $88.2 million based on quotes from the counterparties to these instruments and represents the estimated amount that we would expect to pay if these agreements were terminated. Certain of these counterparties have the option to terminate the swap agreements and demand payment of the fair value of the swaps if YPGL's credit ratings from the three recognized credit rating agencies decline below investment grade. As of June 30, 2006, YPGL's credit ratings from the three recognized credit rating agencies were investment grade; however, if the ratings fell below investment-grade, payment requirements would have been $41.1 million.

Inflation

Inflation has not had a significant impact on our costs.

Table of Contents

Contractual Obligations and Commercial Commitments

We have contractual obligations and commercial commitments that may affect our financial condition. Contractual obligations to make future payments arise from parent company and subsidiary long-term debt and notes payable, operating leases and power and fuel purchase contracts. Other obligations and commitments arise from unused lines of credit and letters of credit. Material obligations and commitments as of June 30, 2006 are as follows (in millions):

	Payments Due By Period				
	Total	Remainder of 2006	2007-2008	2009-2010	2011 and After
Contractual Cash Obligations:					
Parent company senior debt	$ 4,475.0	$ —	$1,550.0	$ —	$ 2,925.0
Parent company subordinated debt	1,596.8	167.0	468.0	422.5	539.3
Subsidiary and project debt	10,948.3	282.9	1,518.8	560.3	8,586.3
Interest payments on long-term debt	14,152.2	571.0	2,060.9	1,623.6	9,896.7
Short-term debt	316.3	316.3	—	—	—
Coal, electricity and natural gas contract commitments(1)	10,543.2	902.6	2,437.9	1,718.3	5,484.4
Owned hydroelectric commitments(1)	705.3	23.3	93.1	177.4	411.5
Operating leases(1)	434.9	48.2	160.8	93.3	132.6
Deferred costs on construction contract(2)	200.0	—	200.0	—	—
Total contractual cash obligations	$43,372.0	$2,311.3	$8,489.5	$4,595.4	$27,975.8

	Commitment Expiration per Period				
	Total	Remainder of 2006	2007-2008	2009-2010	2011 and After
Other Commercial Commitments:					
Unused revolving credit facilities and lines of credit(3) –					
Parent company revolving credit facility	$ 340.1	$ —	$ —	$ 340.1	$ —
Subsidiary revolving credit facilities and lines of credit	1,441.1	—	26.7	1,414.4	—
Total unused revolving credit facilities and lines of credit	$1,781.2	$ —	$ 26.7	$1,754.5	$ —

Parent company letters of credit outstanding	$ 61.0	$ —	$ 61.0	$ —	$ —
Pollution control revenue bond standby letters of credit	$ 296.9	$ —	$ —	$ 296.9	$ —
Pollution control revenue bond standby bond purchase agreements	$ 220.9	$ —	$124.4	$ —	$96.5
Other standby letters of credit	$ 112.7	$17.0	$ 31.3	$ —	$64.4

(1) The coal, electricity and natural gas contract commitments, owned hydroelectric commitments and operating leases are not reflected on the consolidated balance sheets.

(2) MidAmerican Energy is allowed to defer up to $200.0 million in payments to the contractor under its contract to build CBEC Unit 4. Approximately 39.3% of this commitment is expected to be funded by the joint owners of CBEC Unit 4.

(3) These amounts do not reflect the following events occurring in July 2006: (1) the parent company revolving credit facility's capacity was increased by $200.0 million and its maturity date was extended to July 2011; (2) the maturity dates for $1,225.0 million of subsidiary revolving credit facilities were extended to July 2011; and (3) the borrowing capacity of subsidiary revolving credit facilities was increased by $75.0 million.

We have other types of commitments that are subject to change and relate primarily to the items listed below. For additional information, refer, where applicable, to Note 3 and Note 9 of our Notes to the Unaudited Interim Consolidated Financial Statements and to our Notes to the Audited Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus.

- Debt service reserve guarantees
- Asset retirement obligations
- Nuclear decommissioning costs
- Residual guarantees on operating leases
- Pension and postretirement commitments

Off-Balance Sheet Arrangements

We have certain investments that are accounted for under the equity method in accordance with GAAP. Accordingly, an amount is recorded on our balance sheet as an equity investment and is increased or decreased for our pro-rata share of earnings or losses, respectively, less any dividend distribution from such investments.

As of June 30, 2006, our investments that are accounted for under the equity method had $762.3 million of debt and $107.8 million in outstanding letters of credit. As of June 30, 2006, our pro-rata share of such debt and outstanding letters of credit, which is all non-recourse to us except for $35.2 million of outstanding letters of credit (included in the Obligations and Commitments table), was $376.2 million and $51.8 million, respectively.

As noted above, we are generally not required to support the debt service obligations of our equity investments. However, default with respect to this non-recourse debt could result in a loss of invested equity.

New Accounting Pronouncements

In December 2004, the FASB issued SFAS No. 123R, ''Share-Based Payment'' (or SFAS 123R), which replaces SFAS No. 123, ''Accounting for Stock-Based Compensation,'' and supersedes Accounting Principles Board Opinion No. 25, ''Accounting for Stock Issued to Employees.'' SFAS 123R establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services, primarily focusing on the accounting for transactions in which an entity obtains employee services in share-based payment transactions. SFAS 123R requires entities to measure compensation costs for all share-based payments, including stock options, at fair value and expense such payments over the service period. As of January 1, 2006, we adopted SFAS 123R. Adoption of SFAS 123R did not affect our financial position, results of operations or cash flows as all of our outstanding stock options were fully vested on January 1, 2006. Modifications to outstanding stock options after January 1, 2006 may result in additional compensation expense pursuant to the provisions of SFAS 123R.

In July 2006, the FASB issued FASB Interpretation No. 48, ''Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109'' (or FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in accordance with SFAS No. 109, ''Accounting for Income Taxes,'' and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a return. Guidance is also provided on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 is effective for fiscal years beginning after

December 15, 2006. The Company is currently evaluating the impact of adopting FIN 48 on its consolidated financial position and results of operations.

Critical Accounting Policies

The preparation of financial statements and related disclosures in conformity with accounting principles generally accepted in the United States of America requires management to make judgments, assumptions and estimates that affect the amounts reported in the consolidated financial statements and accompanying notes. Note 2 of our Notes to the Audited Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus describes the significant accounting policies and methods used in the preparation of the consolidated financial statements. Estimates are used for, but not limited to, the accounting for the effects of certain types of regulation, impairment of long-lived assets and goodwill, accrued pension and post-retirement expense, income taxes and revenue. Actual results could differ from these estimates. The following critical accounting policies are impacted significantly by judgments, assumptions and estimates used in the preparation of the consolidated financial statements.

Discussion as of December 31, 2005

Accounting for the Effects of Certain Types of Regulation

MidAmerican Energy, Kern River and Northern Natural Gas prepare their financial statements in accordance with the provisions of SFAS No. 71, ''Accounting for the Effects of Certain Types of Regulation (or SFAS 71), which differs in certain respects from the application of GAAP by non-regulated businesses. In general, SFAS 71 recognizes that accounting for rate-regulated enterprises should reflect the economic effects of regulation. As a result, a regulated utility is required to defer the recognition of costs (a regulatory asset) or the recognition of obligations (a regulatory liability) if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, MidAmerican Energy, Kern River and Northern Natural Gas have deferred certain costs and accrued certain obligations, which will be amortized over various future periods. We periodically evaluate the applicability of SFAS 71 and consider factors such as regulatory changes and the impact of competition. If cost-based regulation ends or competition increases, we may have to reduce our asset balances to reflect a market basis less than cost and write off the associated regulatory assets and liabilities.

Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes, recent rate orders received by other regulated entities, and the status of any pending or potential deregulation legislation. Based upon this continual assessment, management believes the existing regulatory assets are probable of recovery. This assessment reflects the current political and regulatory climate at the state and federal levels, and is subject to change in the future. If future recovery of costs ceases to be probable, the asset and liability write-offs would be required to be recognized in operating income. Total regulatory assets were $441.1 million and $451.8 million as of December 31, 2005 and 2004, respectively. Total regulatory liabilities were $773.9 million and $682.8 million as of December 31, 2005 and 2004, respectively. Refer to Note 5 of our Notes to the Audited Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus for additional information regarding our regulatory assets and liabilities.

Impairment of Long-Lived Assets and Goodwill

Our long-lived assets consist primarily of properties, plants and equipment. Depreciation is generally computed using the straight-line method based on economic lives or recovery periods mandated by regulators. We periodically evaluate long-lived assets, including properties, plants and equipment, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. Upon the occurrence of a triggering event, the carrying amount of a long-lived asset is reviewed to assess whether the recoverable amount has declined below its carrying amount. The recoverable amount is the estimated net future cash flows that we expect to recover from

the future use of the asset, undiscounted and without interest, plus the asset's residual value on disposal. Where the recoverable amount of the long-lived asset is less than the carrying value, an impairment loss is recognized to write down the asset to its fair value that is based on discounted estimated cash flows from the future use of the asset.

The estimate of cash flows arising from future use of the asset that are used in the impairment analysis requires judgment regarding what we would expect to recover from future use of the asset. Any changes in the estimates of cash flows arising from future use of the asset or the residual value of the asset on disposal based on changes in the market conditions, changes in the use of the asset, management's plans, the determination of the useful life of the asset and technology changes in the industry could significantly change the calculation of the fair value or recoverable amount of the asset and the resulting impairment loss, which could significantly affect the results of operations. The determination of whether impairment has occurred is primarily based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. An impairment analysis of generating facilities requires estimates of possible future market prices, load growth, competition and many other factors over the lives of the facilities. A resulting impairment loss is highly dependent on these underlying assumptions.

We evaluate the impairment of goodwill under SFAS No. 142, ''Goodwill and Other Intangible Assets.'' The majority of our goodwill at December 31, 2005, relates to the Teton Transaction completed in 2000. The remainder relates to the acquisitions of Yorkshire Electricity in 2001, Kern River and Northern Natural Gas in 2002 and various acquisitions at HomeServices. We perform an annual goodwill impairment test and update the test if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value. Key assumptions used in the analysis include, but are not limited to, the use of an appropriate discount rate and estimated future cash flows. Estimated future cash flows are impacted by, among other factors, assumptions regarding comprehensive energy regulation, changes in regulations and rates, and estimates of future commodity prices. In estimating cash flows, we incorporate current market information, as well as, historical factors. During 2005 and 2004, we recognized impairments on several of our long-lived assets and goodwill. For additional discussion of these impairments refer to Notes 4, 7 and 17 of our Notes to the Audited Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus.

We record goodwill adjustments for (i) changes in the estimates of or the settlement of tax bases of acquired assets, liabilities and carryforwards and items relating to acquired entities' prior income tax returns, (ii) the tax benefit associated with the excess of tax-deductible goodwill over the reported amount of goodwill, and (iii) changes to the purchase price allocation prior to the end of the allocation period, which is generally one year from the acquisition date.

Accrued Pension and Postretirement Expense

We sponsor pension and other retirement and postretirement benefit plans in various forms covering all employees who meet eligibility requirements. We account for these benefits under SFAS No. 87, ''Employers' Accounting for Pensions'' and SFAS No. 106, ''Employers' Accounting for Postretirement Benefits Other Than Pensions,'' respectively. Refer to Note 21 of our Notes to the Audited Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus for additional disclosures regarding our pension and postretirement commitments. The measurement of the pension and postretirement obligations, costs and liabilities is dependent on a variety of assumptions used by the actuaries and us. The critical assumptions used in developing the required estimates include the following key factors:

- discount rate;
- expected return on plan assets; and
- health care cost trend rates.

Other assumptions, such as retirement, mortality, and turnover, are evaluated periodically and updated to reflect actual experience.

For our pension and other postretirement plans, we assumed that our plans' assets would generate an expected return on plan assets of 7.0% for our domestic and United Kingdom plans as of December 31, 2005. These assets are maintained in master trusts. The investment objective of the master trusts is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation targets were set after considering the investment objectives and the risk profiles with respect to each trust. Equity securities, debt securities, real estate and other securities are held for return potential and diversification benefits. Investments within asset classes are to be diversified to achieve broad market participation and reduce the impact of individual managers or investments. We regularly review our actual asset allocations and periodically rebalance our investments to our targeted allocations when considered appropriate.

For our pension and other postretirement plans, we assumed a discount rate of 5.75% in determining the benefit obligations and benefit costs for our domestic plans as of and for the year ended December 31, 2005. Discount rates of 4.75% and 5.25%, respectively, were used in determining the benefit obligations and benefit costs for our United Kingdom plan as of and for the year ended December 31, 2005. Advice from the actuaries and current market conditions were used to determine discount rates. The discount rates used for all plans approximate the discount rates of hypothetical bond portfolios that match our expected payment obligations.

The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded. If a 100 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Domestic Plans				United Kingdom Pension Plan	
	Pension Plans		Other Postretirement Benefit Plans			
	+1.0%	−1.0%	+1.0%	−1.0%	+1.0%	−1.0%
	(in millions)					
Effect on December 31, 2005, Benefit Obligations:						
Discount rate	$(62.1)	$ 75.2	$(28.7)	$35.7	$(220.3)	$280.5
Health care trend rate	N/A	N/A	(26.4)	21.4	N/A	N/A
Effect on 2005 Periodic Cost:						
Discount rate	$ (4.1)	$ 1.9	$ (2.1)	$ 2.1	$ (16.4)	$ 18.2
Health care trend rate	N/A	N/A	(2.4)	1.9	N/A	N/A
Expected return on assets	(5.6)	5.6	(1.4)	1.4	(14.6)	14.6

Income Taxes

We recognize deferred tax assets and liabilities based on the difference between the financial statement and tax basis of assets and liabilities using estimated tax rates in effect for the year in which the differences are expected to reverse. Based on existing regulatory precedent, MidAmerican Energy is not allowed to recognize deferred income tax expense related to certain temporary differences resulting from accelerated tax depreciation and other property related basis differences. For these differences, MidAmerican Energy establishes deferred tax liabilities and regulatory assets on the consolidated balance sheets since MidAmerican Energy is allowed to recover the increased tax expense when these differences turn around.

We have not provided U.S. deferred income taxes on our currency translation adjustment or the cumulative earnings of international subsidiaries that have been determined by management to be reinvested indefinitely. These earnings related to ongoing operations and were approximately $600 million at December 31, 2005. Because of the availability of U.S. foreign tax credits, it is not practicable to determine the U.S. 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 we plan to remit those earnings. We periodically evaluate our cash requirements in the U.S. and abroad and evaluate our short-term and long-term operational and fiscal objectives in determining whether the earnings of its foreign subsidiaries are indefinitely invested outside the U.S. or will be remitted to the U.S. within the foreseeable future.

In preparing our tax returns, management is required to interpret complex tax laws and regulations. We are 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. The Internal Revenue Service has closed examination of our income tax returns through 1998. Although the ultimate resolution of our tax examinations is uncertain, we believe we have made adequate provisions for income tax payables and the aggregate amount of any additional tax liabilities that may result from these examinations, if any, will not have a material adverse affect on our financial condition, results of operations or cash flows. Tax contingency reserves are included in accrued property and other taxes and other long-term accrued liabilities, as appropriate.

Revenue Recognition – Unbilled Revenue

Unbilled revenues were $199.4 million and $185.5 million, respectively, at December 31, 2005 and 2004.

Electric and Natural Gas Retail Revenues and Electric Distribution Revenues

Revenue is recorded based upon services rendered and electricity and natural gas delivered, distributed or supplied to the end of the period. MidAmerican Energy records unbilled revenue representing the estimated amounts customers will be billed between the meter reading dates in a particular month and the end of that month. The distribution businesses in Great Britain record unbilled revenue representing the estimated amounts that customers will be billed for electricity distributed during the period based upon information received from the national settlement system.

For MidAmerican Energy, the determination of sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity and natural gas delivered to customers since the date of their last meter readings are estimated and the corresponding unbilled revenue accrual is then recorded. This estimate is reversed in the following month and actual revenue is recorded based on meter readings.

The monthly estimate for unbilled revenues is calculated by MidAmerican Energy using a number of inputs, including the estimation of total energy provided during the period, line losses, total energy billed, and the average rate per customer class. The estimate of total energy provided and unbilled volumes can vary from period to period depending on seasonal weather patterns, customer usage, production levels due to economic activity, and changes in the composition of customer classes or other variables. The distribution businesses in Great Britain follow a similar process in the determination of revenue, except that the information regarding units distributed through the systems is received from the national settlement system. Differences between the actual and estimated amounts have historically been immaterial.

Natural Gas Transportation and Storage

The majority of the pipelines' transportation and storage revenues are derived from firm reservation charges which are fixed based on contractual quantities and rates. The remaining revenue, consisting primarily of commodity charges, is based on contractual rates and actual or estimated usage based on scheduled quantities and is subject to volume estimates including estimates of meter reading and loss and unaccounted for volumes. Amounts are generally billed on or before the ninth business day of the following month. Historically, any differences between estimated quantities and actual quantities have been immaterial.

Table of Contents

Update Through June 30, 2006

Our critical accounting policies have not changed materially since December 31, 2005, except as they relate to the PacifiCorp acquisition and PacifiCorp's derivative instruments.

PacifiCorp Acquisition

SFAS No. 141, ''Business Combinations'' requires that the total purchase price of acquired companies be allocated to the net tangible and identified intangible assets acquired and liabilities assumed based on their estimated fair values as of the acquisition date. Such a valuation requires management to make significant estimates and assumptions. Management makes estimates of fair value based upon assumptions believed to be reasonable. These estimates are based on historical experience and information obtained from the management of the acquired companies. These estimates are inherently uncertain and unpredictable. Assumptions may be incomplete or inaccurate, and unanticipated events and circumstances may occur which may affect the accuracy or validity of such assumptions, estimates or actual results.

PacifiCorp's operations are regulated, which provide revenue derived from cost, and are accounted for pursuant to SFAS 71. PacifiCorp has demonstrated a past history of recovering its costs incurred through its rate making process. Given the size and timing of the acquisition, the fair values established to date are preliminary and are subject to adjustment as additional information is obtained. When finalized, adjustments to goodwill may result.

We have not identified any material pre-acquisition contingencies where the related asset, liability or impairment is probable and the amount of the asset, liability or impairment can be reasonably estimated. Prior to the end of the purchase price allocation period, if information becomes available that a pre-acquisition related loss had been incurred and the amounts can be reasonably estimated, such items will be included in the purchase price allocation.

Certain transition activities will occur as we integrate PacifiCorp. Costs, consisting primarily of employee termination activities, will be incurred associated with such transition activities. We are in the process of finalizing these plans and expect to execute these plans over the next several months. In accordance with Emerging Issues Task Force Issue No. 95-3, ''Recognition of Liabilities in Connection with a Purchase Business Combination'' (or EITF 95-3), the finalization of certain integration plans will result in adjustments to the purchase price allocation for the acquired assets and assumed liabilities of PacifiCorp. Transition costs that do not meet the criteria in EITF 95-3 are expensed in the period incurred.

Derivative Instruments

PacifiCorp uses derivative instruments (primarily forward purchases and sales) to manage the commodity price risk inherent in its fuel and electricity obligations, as well as to optimize the value of power generation assets and related contracts. These instruments are accounted for under SFAS 133, as amended. PacifiCorp also enters into short-term energy derivatives on a limited basis for arbitrage purposes to take advantage of opportunities arising from market inefficiencies. SFAS 133 applies not only to traditional financial derivative instruments, but to any contract having the accounting characteristics of a derivative.

SFAS 133 requires that derivative instruments be recorded on the balance sheet at fair value. The fair values of derivative instruments are determined using forward price curves. Forward price curves represent PacifiCorp's estimates of the prices at which a buyer or seller could contract today for delivery or settlement of a commodity at future dates. PacifiCorp bases its forward price curves upon market price quotations when available and uses internally developed, modeled prices when market quotations are unavailable. In general, PacifiCorp estimates the fair value of a contract by calculating the present value of the difference between the contract and the applicable forward price curve.

Price quotations for certain major electricity trading hubs are generally readily obtainable for the first six years and, therefore, PacifiCorp's forward price curves for those locations and periods reflect

Table of Contents

observable market quotes. However, in the later years or for locations that are not actively traded, forward price curves must be estimated in other ways. For short-term contracts at less actively traded locations, prices are modeled based on observed historical price relationships with actively traded locations. For long-term contracts extending beyond six years, the forward price curve is based upon the use of a fundamentals model (cost-to-build approach), due to the limited information available. Factors used in the fundamentals model include the forward prices for the commodities used as fuel to generate electricity, the expected system heat rate (which measures the efficiency of power plants in converting fuel to electricity) in the region where the purchase or sale takes place and a fundamentals forecast of expected spot prices for a commodity in a region based on modeled supply of and demand for the commodity in the region. The assumptions in these models are critical, since any changes in assumptions could have a significant impact on the fair value of the contract.

Despite the large volume of implementation guidance, SFAS 133 and the supplemental guidance do not provide specific guidance on all contract issues. As a result, significant judgment must be used in applying SFAS 133 and its interpretations.

Table of Contents

QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

We are exposed to market risks associated with electric and natural gas prices, foreign currency exchange rates, interest rates, and credit risks. Risk is an inherent part of our business and activities. The risk management process established by each business platform is designed to identify, assess, monitor, report, manage, and mitigate each of the various types of risk involved in its business. To assist in managing the risk, management enters into various transactions, including derivative transactions, consistent with these established procedures. These activities are generally described below. Notes 2 and 14 of our Notes to the Audited Consolidated Financial Statements included in the ‘‘Financial Statements’’ section of this prospectus contain additional information regarding the accounting for derivative contracts pursuant to SFAS 133, as amended, at our platforms.

Discussion as of December 31, 2005

As of December 31, 2005, we held derivative instruments with the following fair values (in millions):

	Commodity					
	MidAmerican Energy	Northern Natural Gas	Other	Foreign Exchange Swaps	Interest Rate Locks	Total
Maturity:						
2006	$ (9.0)	$ 1.2	$ (6.0)	$ —	$ —	$ (13.8)
2007 – 2009	(5.2)	(6.7)	(4.8)	(77.5)	—	(94.2)
After 2009	—	(0.6)	—	—	—	(0.6)
Total	$ (14.2)	$ (6.1)	$(10.8)	$ (77.5)	$ —	$(108.6)

Commodity Price Risk

MidAmerican Energy – Gas

Under the current regulatory framework, MidAmerican Energy is allowed to recover its cost of gas from all of its regulated gas customers through a purchased gas adjustment clause included in revenue. Accordingly, MidAmerican Energy’s regulated gas customers, although ensured of the availability of gas supplies, retain the risk associated with market price volatility. In order to mitigate a portion of the market price risk retained by its regulated gas customers through the purchased gas adjustment clause, MidAmerican Energy uses natural gas futures, options and over-the-counter agreements. The realized gains and losses on these derivative instruments are assigned to regulated gas customers through the purchased gas adjustment clause.

MidAmerican Energy – Electric

MidAmerican Energy is exposed to variations in the price of fuel for generation and the price of wholesale power to be purchased or sold. Under typical operating conditions, MidAmerican Energy has sufficient generation to supply its regulated retail electric needs, but may, at times, need to purchase electric power. MidAmerican Energy may incur a loss if the costs of fuel for generation or purchases of electric power are higher than MidAmerican Energy is permitted to recover from its customers under current electric rates. MidAmerican Energy uses physical and financial forward contracts to mitigate these regulated electric price risks.

Derivative instruments are used to economically hedge both committed and forecasted energy purchases and sales. Realized gains and losses on all hedges are recognized in income as operating revenues, cost of fuel, energy and capacity; or cost of gas sold, depending upon the nature of the item being hedged. Net unrealized gains and losses on hedges utilized for regulated purposes are recorded as regulatory assets or liabilities.

Northern Natural Gas

On an annual basis, Northern Natural Gas enters into equivalent volume forward transactions at negotiated fixed prices that generally provide for the sale of gas in the first six months of the year and

the purchase of equivalent volumes in the final six months of the year to lock in the cash flows relating to anticipated near-term index-based sales and purchases of operational storage volumes. Since these sale and purchase transactions are a normal and recurring method of managing seasonal changes in operational storage volumes and are expected to result in physical deliveries, such transactions are deemed to be normal sales and purchases that qualify for the exemption from fair value accounting under SFAS 133.

Northern Natural Gas has also entered into longer term natural gas commodity swaps of equivalent volume transactions at negotiated fixed prices to hedge the cash flows of anticipated longer term operational gas sales and purchases. These agreements are designated as cash flow hedges under SFAS 133.

Additionally, Northern Natural Gas has entered into natural gas commodity swaps to hedge the cash flows of anticipated future preferred delivery storage contracts. The objective of these transactions is to lock in the cash flows relating to the price spreads of natural gas storage contracts that are sensitive to gas commodity prices. These agreements are also designated as cash flow hedges under SFAS 133.

Currency Exchange Rate Risk

CE Electric UK

We are exposed to foreign currency risk from investments in businesses owned and operated by CE Electric UK. At December 31, 2005, our primary foreign currency rate exposures were with the sterling. A 10% devaluation in the currency exchange rate would result in our consolidated balance sheet being negatively impacted by a $132.3 million cumulative translation adjustment in accumulated other comprehensive income. A 10% devaluation in the average currency exchange rate would have resulted in lower reported earnings for CE Electric UK of $21.0 million in 2005.

CE Electric UK has entered into certain currency rate swap agreements for its senior notes and Yankee bonds with large multi-national financial institutions. The swap agreements effectively convert the U.S. dollar fixed interest rate to a fixed rate in sterling for $237.0 million of 6.995% senior notes and $281.0 million of 6.496% Yankee bonds outstanding at December 31, 2005. The agreements extend until December 30, 2007 and February 25, 2008, respectively. The estimated fair value of these swap agreements at December 31, 2005 and 2004, was $77.5 million and $131.8 million, respectively, based on quotes from the counterparties to these instruments and represents the estimated amount that we would expect to pay if these agreements were terminated.

A 10% devaluation of the U.S. dollar versus sterling from the value at December 31, 2005 would increase the amount owed by us if these swap agreements were terminated by approximately $62.0 million.

CalEnergy Generation-Foreign

CalEnergy Generation-Foreign has mitigated a significant portion of its foreign currency risk as PNOC-EDC’s and NIA’s obligations under the project agreements are substantially denominated in U.S. dollars.

Interest Rate Risk

At December 31, 2005, we had fixed-rate long-term debt of $11,348.0 million in aggregate principal amount and having a fair value of $12,066.0 million. These instruments are fixed-rate and therefore do not expose us to the risk of earnings loss due to changes in market interest rates. However, the fair value of these instruments would decrease by approximately $434 million if interest rates were to increase by 10% from their levels at December 31, 2005. In general, such a decrease in fair value would impact earnings and cash flows only if we were to reacquire all or a portion of these instruments prior to their maturity.

At December 31, 2004, we had fixed-rate long-term debt of $11,503.4 million in aggregate principal amount and having a fair value of $12,416.2 million. These instruments were fixed-rate and therefore did not expose us to the risk of earnings loss due to changes in market interest rates.

At December 31, 2005, we had floating-rate obligations of $166.7 million that expose us to the risk of increased interest expense in the event of increases in short-term interest rates. These obligations are not hedged; however, any increase in floating rates would not have a material effect on our consolidated interest expense.

At December 31, 2004, we had floating-rate obligations of $493.4 million that exposed us to the risk of increased interest expense in the event of increases in short-term interest rates. These obligations were not hedged.

We may enter into contractual agreements to hedge exposure to interest rate risk. Changes in fair value of interest rate ''locks'' used as cash flow hedges are reported in accumulated other comprehensive income to the extent the hedge is effective until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense over the term of the related debt issuance. In May 2005, we entered into a treasury rate lock agreement in the notional amount of $1.6 billion to protect against a rise in interest rates related to the anticipated financing of the PacifiCorp acquisition. At December 31, 2005, the market value of this agreement was zero.

Credit Risk

Domestic Regulated Operations

MidAmerican Energy's utility operations grant unsecured credit to its retail electric and gas customers, substantially all of whom are local businesses and residents, which totaled $186.0 million at December 31, 2005. MidAmerican Energy also extends unsecured credit to other utilities, energy marketers, financial institutions and certain commercial and industrial end-users in conjunction with wholesale energy marketing activities. MidAmerican Energy analyzes the financial condition of each significant counterparty before entering into any transactions, establishes limits on the amount of unsecured credit to be extended to each counterparty, and evaluates the appropriateness of unsecured credit limits on a daily basis. MidAmerican Energy seeks to negotiate contractual arrangements with wholesale counterparties to provide for net settlement of monthly accounts receivable and accounts payable and net settlement of contracts for future performance in the event of default. At December 31, 2005, 84.4% of MidAmerican Energy's credit exposure, net of collateral, from wholesale operations was with counterparties having ''investment grade'' credit ratings from Moody's or Standard & Poor's, while an additional 7.4% of MidAmerican Energy's credit exposure, net of collateral, from wholesale operations was with counterparties having financial characteristics deemed equivalent to ''investment grade'' by MidAmerican Energy based on internal review.

Northern Natural Gas' primary customers include regulated local distribution companies in the upper Midwest. Kern River's primary customers are electric generating companies and energy marketing and trading companies in the western United States. 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 or traders and sell the electricity to end-use customers, use Northern Electric's and Yorkshire Electricity's distribution networks pursuant to an industry standard ''Distribution Use of System Agreement,'' which Northern Electric and Yorkshire Electricity separately entered into with the various suppliers of electricity in their respective distribution service areas. Northern Electric's and Yorkshire Electricity's customers are concentrated in a small number of electricity supply businesses with RWE Npower plc (or Npower) accounting for approximately 44% of distribution revenues in

2005. Ofgem has determined a framework which sets credit limits for each supply business 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 cover must be 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

PNOC-EDC's and NIA's obligations under the project agreements are the Leyte Projects' and Casecnan Project'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 agreements 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 CalEnergy Generation-Foreign was $312.3 million for the year ended December 31, 2005. The Leyte Projects' agreements expire in June 2006 and July 2007, respectively, while the Casecnan Project's agreement expires in December 2021.

Update Through June 30, 2006

Our exposure to market risk has not changed materially since December 31, 2005, except for additional risks related to the acquisition of PacifiCorp.

PacifiCorp participates in a wholesale energy market that includes public utility companies, electricity and natural gas marketers, financial institutions, industrial companies and government entities. A variety of products exist in this market, ranging from electricity and natural gas purchases and sales for physical delivery to financial instruments such as futures, swaps, options and other complex derivatives. Transactions may be conducted directly with customers and suppliers, through brokers, or with an exchange that serves as a central clearing mechanism.

PacifiCorp is subject to the various risks inherent in the energy business, including credit risk, interest rate risk and commodity price risk. The risk management process established by PacifiCorp is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its businesses. To assist in managing the volatility relating to these exposures, PacifiCorp enters into various transactions, including derivative transactions, consistent with PacifiCorp's risk management policy and procedures. The risk management policy governs energy transactions and is designed for hedging PacifiCorp's existing energy and asset exposures, and to a limited extent, the policy permits arbitrage activities to take advantage of market inefficiencies. The policy and procedures also govern PacifiCorp's use of derivative instruments for commodity derivative transactions, as well as its energy purchase and sales practices, and describe PacifiCorp's credit policy and management information systems required to effectively monitor such derivative use. PacifiCorp's risk management policy provides for the use of only those instruments that have a similar volume or price relationship to its portfolio of assets, liabilities or anticipated transactions, thereby ensuring that such instruments will be primarily used for hedging. PacifiCorp's portfolio of energy derivatives is primarily used for non-trading purposes.

PacifiCorp continues to actively manage its exposure to commodity price volatility. These activities may include adding to the generation portfolio and entering into transactions that help to shape PacifiCorp's system resource portfolio, including wholesale contracts and financially settled temperature-related derivative instruments that reduce volume and price risk due to weather extremes.

Table of Contents

Credit Risk

Credit risk relates to the risk of loss that might occur as a result of non-performance by counterparties of 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 such counterparty.

To mitigate exposure to the financial risks of wholesale counterparties, PacifiCorp has entered into netting and collateral arrangements that 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 receipts. If required, PacifiCorp exercises rights under these arrangements, including calling on the counterparty's credit support arrangement. At June 30, 2006, 80.8% of PacifiCorp's credit exposure, net of collateral, within its electricity and natural gas portfolio of purchase and sale contracts was with counterparties having ‘‘investment grade’’ credit ratings from at least one major credit rating agency.

Interest Rate Risk

PacifiCorp is exposed to risk resulting from changes in interest rates as a result of its issuance of variable-rate debt and commercial paper. PacifiCorp manages its interest rate exposure by maintaining a blend of fixed-rate and variable-rate debt and by monitoring the effects of market changes in interest rates. Changing interest rates will affect interest paid on variable-rate debt and interest earned by PacifiCorp's pension plan assets, mining reclamation trust funds and cash balances. PacifiCorp's principal sources of variable-rate debt are commercial paper and pollution control revenue bonds remarketed on a periodic basis. Commercial paper is periodically refinanced with fixed-rate debt when needed and when interest rates are considered favorable. PacifiCorp may also enter into financial derivative instruments, including interest rate swaps, swaptions and United States Treasury lock agreements, to manage and mitigate interest rate exposure. PacifiCorp does not anticipate using financial derivatives as the principal means of managing interest rate exposure. Increases or decreases in interest rates are reflected in PacifiCorp's cost of debt calculation as rate cases are filed. Any adverse change to PacifiCorp's credit rating could negatively impact PacifiCorp's ability to borrow and the interest rates that are charged.

As of June 30, 2006, PacifiCorp had fixed-rate long-term debt of $3,405.2 million in aggregate principal amount and having a fair value of $3,484.1 million. These instruments are fixed-rate and therefore do not expose PacifiCorp to the risk of earnings loss due to changes in market interest rates. However, the fair value of these instruments would decrease by approximately $115 million if interest rates were to increase by 10% from their levels at June 30, 2006. In general, such a decrease in fair value would impact earnings and cash flows only if PacifiCorp were to reacquire all or a portion of these instruments prior to their maturity.

As of June 30, 2006, PacifiCorp had $845.8 million of variable-rate liabilities and $74.1 million of temporary cash investments and PacifiCorp had no financial derivatives in effect relating to interest rate exposure. Based on a sensitivity analysis as of June 30, 2006, for a one-year horizon, PacifiCorp estimates that if market interest rates average 1.0% higher (lower), interest expense, net of offsetting impacts on interest income, would increase (decrease) by $7.7 million. This amount includes the effect of invested cash and was determined by considering the impact of the hypothetical interest rates on the variable-rate securities outstanding as of June 30, 2006. If interest rates changed significantly, PacifiCorp might take actions to manage its exposure to the change. However, due to the uncertainty of the specific actions that might be taken and their possible effects, the sensitivity analysis assumes no changes in PacifiCorp's financial structure.

Table of Contents

Commodity Price Risk

PacifiCorp's exposure to market risk due to commodity price change is primarily related to its fuel and electricity commodities, which are subject to fluctuations due to unpredictable factors, such as weather, electricity demand and plant performance, that affect energy supply and demand. PacifiCorp's energy purchase and sales activities are governed by PacifiCorp's risk management policy and the risk levels established as part of that policy.

PacifiCorp's energy commodity price exposure arises primarily from its electric supply obligation in the western United States. PacifiCorp manages this risk principally through the operation of its generation plants with an aggregate facility net owned capacity of 8,469.9 MW, as well as transmission rights held both on some of its own approximately 15,600-mile transmission system and on third-party transmission systems, and through its wholesale energy purchase and sales activities. Wholesale contracts are utilized primarily to balance PacifiCorp's physical excess or shortage of net electricity for future time periods. Financially settled contracts are utilized to further mitigate commodity price risk. PacifiCorp may from time to time enter into other financially settled, temperature-related derivative instruments that reduce volume and price risk on days with weather extremes. In addition, a financially settled hydroelectric streamflow hedge is in place through September 2006 to reduce volume and price risks associated with PacifiCorp's hydroelectric generation resources.

The fair value of derivative instruments is determined using forward price curves. Forward price curves represent PacifiCorp's estimates of the prices at which a buyer or seller could contract today for delivery or settlement of a commodity at future dates. PacifiCorp bases its forward price curves upon market price quotations when available and internally developed and commercial models with internal and external fundamental data inputs when market quotations are unavailable. In general, PacifiCorp estimates the fair value of a contract by calculating the present value of the difference between the prices in the contract and the applicable forward price curve. Price quotations for certain major electricity trading hubs are generally readily obtainable for the first six years, and therefore PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. However, in the later years or for locations that are not actively traded, PacifiCorp must develop forward price curves. For short-term contracts at less actively traded locations, prices are modeled based on observed historical price relationships with actively traded locations. For long-term contracts extending beyond six years, the forward price curve is based upon the use of a fundamentals model (cost-to-build approach) due to the limited information available.

Factors used in the fundamentals model include the forward prices for the commodities used as fuel to generate electricity, the expected system heat rate (which measures the efficiency of electricity plants in converting fuel to electricity) in the region where the purchase or sale takes place and a fundamental forecast of expected spot prices based on modeled supply and demand in the region. The assumptions in these models are critical since any changes to the assumptions could have a significant impact on the fair value of the contract. Contracts with explicit or embedded optionality are valued by separating each contract into its physical and financial forward and option components. Forward components are valued against the appropriate forward price curve. The optionality is valued using a modified Black-Scholes model or a stochastic simulation (Monte Carlo) approach. Each option component is modeled and valued separately using the appropriate forward price curve. PacifiCorp's valuation models and assumptions are continuously updated to reflect current market information, and evaluations and refinements of model assumptions are performed on a periodic basis.

The following table shows summarized information (in millions) with respect to contractual maturities of PacifiCorp's energy-related contracts, primarily used for non-trading purposes, qualifying as derivatives under SFAS 133 as of June 30, 2006.

	Regulatory net asset (liability)	**Total**
Maturity:		
Less than 1 year	$ (78.5)	$ 107.4
1-3 years	(60.2)	90.3
4-5 years	(17.1)	20.4
Excess of 5 years	225.3	(223.4)
Total	$ 69.5	$ (5.3)

BUSINESS

General

We are a United States-based global energy company. We are a consolidated subsidiary of Berkshire Hathaway. The balance of our common stock is owned by a private investor group comprised of Walter Scott, Jr. (including family members and related entities), who is a member of our Board of Directors, David L. Sokol, our Chairman and Chief Executive Officer, and Gregory E. Abel, our President and Chief Operating Officer. As of June 30, 2006, Berkshire Hathaway, Walter Scott, Jr. (including family members and related entities), David L. Sokol and Gregory E. Abel owned 88.2%, 11.1%, 0.6% and 0.1%, respectively, of our voting common stock and held diluted ownership interests of 86.6%, 10.8%, 1.6% and 1.0%, respectively.

Our operations are organized and managed as eight distinct platforms: PacifiCorp, MidAmerican Funding, which primarily includes MidAmerican Energy, Northern Natural Gas, Kern River, CE Electric UK, which primarily includes Northern Electric and Yorkshire Electricity, CalEnergy Generation-Foreign, CalEnergy Generation-Domestic and HomeServices. Refer to Note 22 of our Notes to the Audited Consolidated Financial Statements included in the ‘‘Financial Statements’’ section of this prospectus for additional segment information regarding our platforms. Through these platforms we own and operate an electric utility company in the western United States, a combined electric and natural gas utility company in the midwestern United States, two natural gas pipeline companies in the United States, two electricity distribution companies in Great Britain, a diversified portfolio of domestic and international independent power projects and the second-largest residential real estate brokerage firm in the United States. On May 10, 2006, the PacifiCorp Board of Directors elected to change PacifiCorp's fiscal year-end from March 31 to December 31. PacifiCorp's report covering the transition period beginning April 1, 2006 and ending December 31, 2006 will be filed on Form 10-K.

Our energy subsidiaries generate, transmit, store, distribute and supply energy. As of June 30, 2006, our electric and natural gas utility subsidiaries currently serve approximately 6.1 million electricity customers and approximately 685,000 natural gas customers. Our natural gas pipeline subsidiaries operate interstate natural gas transmission systems with approximately 17,600 miles of pipeline in operation, a peak delivery capacity of 6.6 billion cubic feet of natural gas per day and transported approximately 7.8% of the total natural gas consumed in the United States in 2005. As of June 30, 2006, we have interests in 15,601 net owned MW of power generation facilities in operation and under construction, including 14,158 net owned MW in facilities that are part of the regulated asset base of its electric utility businesses and 1,443 net owned MW in non-utility power generation facilities. Substantially all of our non-utility power generation facilities have long-term contracts for the sale of energy and/or capacity from the facilities.

Each of our direct and indirect subsidiaries is organized as a legal entity separate and apart from us and our 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 project or subsidiary debt. It should not be assumed that any asset of any subsidiary of ours will be available to satisfy our obligations or any of our other subsidiaries' obligations, and we have made certain regulatory commitments limiting such availability. However, unrestricted cash or other assets which are available for distribution may, subject to applicable law and the terms of financing and ring-fencing arrangements for such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to us or our affiliates.

Our principal executive offices are located at 666 Grand Avenue, Des Moines, Iowa 50309, and our telephone number is (515) 242-4300. We initially incorporated in 1971 under the laws of the State of Delaware and reincorporated in 1999 in Iowa, at which time we changed our name from CalEnergy Company, Inc. to MidAmerican Energy Holdings Company.

PacifiCorp

General

PacifiCorp, our indirect wholly owned subsidiary, was acquired by us in March 2006 and is a public utility company, headquartered in Oregon, which serves approximately 1.6 million regulated retail electric customers in service territories in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. The combined service territory's diverse regional economy ranges from rural, agricultural and mining areas to urbanized manufacturing and government service centers. No single segment of the economy dominates the service territory, which mitigates PacifiCorp's exposure to economic fluctuations. In the eastern portion of the service territory, mainly consisting of Utah, Wyoming and southeast Idaho, the principal industries are manufacturing, health services, recreation and mining or extraction of natural resources. In the western portion of the service territory, mainly consisting of Oregon, southeastern Washington and northern California, the principal industries are agriculture and manufacturing, with forest products, food processing, high technology and primary metals being the largest industrial sectors. In addition to retail sales, PacifiCorp sells electric energy to other utilities, marketers and municipalities. These sales are referred to as wholesale sales.

Electric Operations

Customers

The percentages of electricity sold (measured in MWh) to retail and wholesale customers, by class of customer, and the total number of retail customers (in thousands) were as follows:

	Years Ended March 31,		
	2006	**2005**	**2004**
Residential	23.4%	22.7%	23.3%
Commercial	23.5	23.5	23.2
Industrial	31.1	31.3	30.8
Wholesale	21.1	21.4	21.6
Other	0.9	1.1	1.1
	100.0%	100.0%	100.0%
Total retail customers	1,640	1,605	1,570

The percentages of retail electric operating revenue, by jurisdiction, were as follows:

	Years Ended March 31,		
	2006	**2005**	**2004**
Utah	40.9%	40.6%	38.5%
Oregon	29.3	29.3	31.5
Wyoming	13.3	13.6	12.8
Washington	8.4	8.0	8.4
Idaho	5.7	6.1	6.3
California	2.4	2.4	2.5
	100.0%	100.0%	100.0%

As a result of the geographically diverse area of operations, PacifiCorp's service territory has historically experienced complementary seasonal load patterns. In the western portion, customer demand peaks in the winter months due to heating requirements. In the eastern portion, customer demand peaks in the summer when irrigation and air-conditioning systems are heavily used.

For residential customers, within a given year, weather conditions are the dominant cause of usage variations from normal seasonal patterns. Strong Utah residential growth over the last several years and increasing installations of central air conditioning systems have contributed to faster summer peak growth.

Table of Contents

Power and Fuel Supply

The following table shows the estimated percentage of PacifiCorp's total energy requirements supplied by its generation plants and through short- and long-term contracts or spot market purchases as follows:

	Years Ended March 31,		
	2006	2005	2004
Coal	67.5%	67.3%	67.8%
Natural gas	3.8	4.2	4.1
Hydroelectric	6.2	4.6	5.4
Wind	0.2	0.2	0.2
Other	0.5	0.6	0.6
Total energy generated	78.2	76.9	78.1
Energy purchased – long-term contracts	8.8	7.9	8.9
Energy purchased – other	13.0	15.2	13.0
	100.0%	100.0%	100.0%

The share of PacifiCorp's energy requirements generated by its plants will vary from year to year and is determined by factors such as planned and unplanned outages, availability and price of coal and natural gas, precipitation and snowpack levels, environmental considerations and the market price of electricity.

As of June 30, 2006, PacifiCorp had an estimated 246.8 million tons of recoverable coal reserves in mines owned or leased by it. During the year ended March 31, 2006, these mines supplied 32.3% of PacifiCorp's total coal requirements, compared to 28.6% during the year ended March 31, 2005 and 30.4% during the year ended March 31, 2004. The remaining coal requirements are acquired through other long-term and short-term contracts. PacifiCorp-owned mines are located adjacent to many of its coal-fired generating plants, which significantly reduces overall transportation costs included in fuel expense.

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 at June 30, 2006, based on PacifiCorp's most recent engineering studies, were as follows:

Location	Plant Served	Mining Method	Recoverable Tons (in millions)
Craig, CO	Craig	Surface	47.9(a)
Huntington & Castle Dale, UT	Huntington and Hunter	Underground	60.5(b)
Rock Springs, WY	Jim Bridger	Surface/Underground	138.4(c)

(a) 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 21.4%.

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

(c) These coal reserves are leased and mined by Bridger Coal Company, a joint venture between Pacific Minerals, Inc. and a subsidiary of Idaho Power Company. PMI, a subsidiary of PacifiCorp, has a two-thirds interest in the joint venture. The Bridger mine is in the process of conversion from surface operation to primarily underground operation, while currently continuing production at its surface operations.

PacifiCorp believes that the respective coal reserves available to the Craig, Huntington, Hunter and Jim Bridger Plants, together with coal available under both long-term and short-term contracts with external suppliers, will be substantially sufficient to provide these plants with fuel for their

Table of Contents

current economically useful lives. Recoverability by surface mining methods typically ranges from 90.0% to 95.0%. Recoverability by underground mining techniques ranges from 50.0% to 70.0%. 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 and require payment of rents and royalties.

PacifiCorp also uses natural gas as fuel for intermediate and peak demand electric generation. Oil and natural gas are 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 FERC with terms of 30 to 50 years. Several of PacifiCorp's long-term operating licenses have expired or will expire in the next few years. Hydroelectric facilities operating under expired licenses may operate under annual licenses granted by the FERC until new operating licenses are issued. Hydroelectric relicensing and the related environmental compliance requirements are subject to a degree of uncertainty. PacifiCorp expects that future costs relating to these matters may be significant and consist primarily of additional relicensing costs and capital expenditures. Electricity generation reductions may also result from additional environmental requirements.

In addition to its portfolio of generating plants, PacifiCorp purchases electricity in the wholesale markets to meet its retail load obligations, long-term wholesale obligations, and energy and capacity balancing requirements. Many of PacifiCorp's purchased electricity contracts have fixed-price components, which provide some protection against price volatility. PacifiCorp enters into wholesale purchase and sale transactions to balance its supply when generation and retail loads are higher or lower than expected. Generation varies with the levels of outages, hydroelectric generation conditions and transmission constraints. Retail load varies with the weather, distribution system outages, consumer trends and the level of economic activity. In addition, PacifiCorp purchases electricity in the wholesale markets when it is more economical than generating it at its own plants. PacifiCorp may also sell into the wholesale market excess electricity arising from imbalances between generation and retail load obligations, subject to pricing and transmission constraints.

PacifiCorp's wholesale transactions are integral to its retail business, providing for a balanced and economically hedged position and enhancing the efficient use of its generating capacity over the long term. Historically, PacifiCorp has been able to purchase electricity from utilities in the western United States for its own requirements. These purchases are conducted through PacifiCorp and third party transmission systems, which connect with market hubs in the Pacific Northwest to provide access to normally low-cost hydroelectric generation and in the southwestern United States to provide access to normally higher-cost fossil-fuel generation. The transmission system is available for common use consistent with open-access regulatory requirements.

PacifiCorp manages its natural gas supply requirements and its wholesale transactions by entering into various financial derivative instruments, including swaps, options and forward physical contracts. Refer to the ''Quantitative and Qualitative Disclosures About Market Risk'' section of this prospectus for a discussion of PacifiCorp's commodity price risk and derivative instruments.

Table of Contents

The following table sets out certain information concerning PacifiCorp's power generating facilities as of June 30, 2006:

	Location	Energy Source	Installed	Facility Net Capacity (MW)(1)	Net MW Owned(1)
COAL:					
Jim Bridger	Rock Springs, WY	Coal	1974-1979	2,120.0	1,413.4
Huntington	Huntington, UT	Coal	1974-1977	895.0	895.0
Dave Johnston	Glenrock, WY	Coal	1959-1972	762.0	762.0
Naughton	Kemmerer, WY	Coal	1963-1971	700.0	700.0
Hunter No. 1	Castle Dale, UT	Coal	1978	430.0	403.1
Hunter No. 2	Castle Dale, UT	Coal	1980	430.0	259.3
Hunter No. 3	Castle Dale, UT	Coal	1983	460.0	460.0
Cholla No. 4	Joseph City, AZ	Coal	1981	380.0	380.0
Wyodak	Gillette, WY	Coal	1978	335.0	268.0
Carbon	Castle Gate, UT	Coal	1954-1957	172.0	172.0
Craig Nos. 1 and 2	Craig, CO	Coal	1979-1980	856.0	165.0
Colstrip Nos. 3 and 4	Colstrip, MT	Coal	1984-1986	1,480.0	148.0
Hayden No. 1	Hayden, CO	Coal	1965-1976	184.0	45.1
Hayden No. 2	Hayden, CO	Coal	1965-1976	262.0	33.0
				9,466.0	6,103.9
NATURAL GAS AND OTHER:					
Currant Creek	Mona, UT	Natural gas/Steam	2005-2006	523.0	523.0
Hermiston	Hermiston, OR	Natural gas/Steam	1996	474.0	237.0
Gadsby Steam	Salt Lake City, UT	Natural gas	1951-1952	235.0	235.0
Gadsby Peakers	Salt Lake City, UT	Natural gas	2002	120.0	120.0
Little Mountain	Odgen, UT	Natural gas	1972	14.0	14.0
Camas Co-Gen	Camas, WA	Black liquor	1996	22.0	22.0
Blundell (2)	Milford, UT	Geothermal	1984	23.0	23.0
				1,411.0	1,174.0
HYDROELECTRIC PLANTS:					
Swift No. 1	Cougar, WA	Lewis River	1958	264.0	264.0
Merwin	Ariel, WA	Lewis River	1931-1958	144.0	144.0
Yale	Amboy, WA	Lewis River	1953	165.0	165.0
Five North Umpqua Plants	Toketee Falls, OR	N. Umpqua River	1950-1956	138.5	138.5
John C. Boyle	Keno, OR	Klamath River	1958	94.0	94.0
Copco Nos. 1 and 2 Plants	Hornbrook, CA	Klamath River	1918-1925	54.5	54.5
Clearwater Nos. 1 and 2 Plants	Toketee Falls, OR	Clearwater River	1953	41.0	41.0
Grace	Grace, ID	Bear River	1908-1923	33.0	33.0
Prospect No. 2	Prospect OR	Rogue River	1928	36.0	36.0
Cutler	Collingston, UT	Bear River	1927	29.1	29.1
Oneida	Preston, ID	Bear River	1915-1920	28.0	28.0
Iron Gate	Hornbrook, CA	Klamath River	1962	20.0	20.0
Soda	Soda Springs, ID	Bear River	1924	14.0	14.0
Fish Creek	Toketee Falls, OR	Fish Creek	1952	12.0	12.0
31 minor hydroelectric plants	Various	Various	1895-1990	86.3	86.3

				1,159.4	1,159.4
WIND PLANT:					
Foote Creek	Arlington, WY	Wind	1998	32.6	32.6
Total Available Generating Capacity				12,069.0	8,469.9
PROJECTS UNDER CONSTRUCTION:					
Lake Side	Vineyard, UT	Natural gas/Steam	N/A	550.0	550.0
				12,619.0	9,019.9

(1) Facility net capacity (MW) represents the total capability of a generating unit as demonstrated by test or by actual operating experience, less power generated and used for auxiliaries and other station uses, and is determined using average annual temperatures.

(2) As a result of the settlement agreement between us, the Utah Committee of Consumer Services, a state utility consumer advocate, and Utah Industrial Energy Consumers, we contributed to PacifiCorp, at no cost, our indirect 100.0% ownership interest in Intermountain Geothermal Company (or IGC), which controlled 69.3% of the steam rights associated with the geothermal field serving PacifiCorp's Blundell Geothermal Plant in Utah. Therefore, IGC became a wholly owned subsidiary of PacifiCorp in March 2006, subsequent to the sale of PacifiCorp to us. IGC obtained ownership of an additional 25.2% of the steam rights during June and July 2006 and therefore now owns 94.5% of the steam rights associated with the geothermal field serving the Blundell Plant.

In May 2002, PacifiCorp entered into a 15-year operating lease for an electric generation facility with West Leasing Company, LLC (or West Valley), an indirect subsidiary of ScottishPower. The Utah facility consists of five generation units with an aggregate net plant capacity of 202.0 MW. PacifiCorp, at its sole option, may terminate the lease, or purchase the facility, if written notice is provided to West Valley on or before December 1, 2006. If the termination option is exercised, the lease would end in May 2008.

Future Generation

As required by state regulators, PacifiCorp uses Integrated Resource Plans 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 Integrated Resource Plan 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 Integrated Resource Plan is a coordinated effort with stakeholders in each of the six states where PacifiCorp operates. Each state commission that has Integrated Resource Plan adequacy rules judges whether the Integrated Resource Plan reasonably meets its standards and guidelines at the time the Integrated Resource Plan is filed. If the Integrated Resource Plan is found to be adequate, then it is formally ‘‘acknowledged.’’ The Integrated Resource Plan can then be used as evidence by parties in rate-making or other regulatory proceedings.

In November 2005, PacifiCorp released an update to its 2004 Integrated Resource Plan. The updated 2004 Integrated Resource Plan identified a need for approximately 2,113 MW of additional resources by summer 2014, to be met with a combination of thermal generation (1,936 MW) and load-control programs (177 MW). PacifiCorp also planned to implement energy conservation programs of 450 average MW, to continue to seek procurement of 1,400 MW of economic renewable resources and to use wholesale electricity transactions to make up for the remaining difference between retail load obligations and available resources.

In July 2006, PacifiCorp filed its 2012 draft request for proposal with the UPSC, OPUC and WUTC. The draft request for proposal is for load resources of between 1,600 MW and 2,290 MW to be available in 2012 through 2014. It is anticipated that each of these commissions will issue its order in October 2006 approving the draft request for proposal, at which time the request for proposal will be issued. The scope of this draft request for proposal is focused on resources capable of delivering energy and capacity in or to PacifiCorp's network transmission system in PacifiCorp's eastern control area. All transaction and resource decisions will be evaluated on a comparable least-cost and risk-balanced approach.

In March 2006, PacifiCorp completed construction of the Currant Creek Power Plant, a 523-MW combined-cycle plant in Utah. Total project costs incurred through June 30, 2006 were approximately $339 million. Presently under construction is the Lake Side Power Plant, an estimated 550-MW combined-cycle plant in Utah, expected to be in service by the summer of 2007. The cost of the Lake Side Power Plant is expected to total approximately $347 million, of which approximately $251 million has been incurred through June 30, 2006. Both plants are 100% owned and operated by PacifiCorp.

In July 2006, PacifiCorp entered into an agreement to acquire a 100.5-MW (nameplate ratings) wind energy generation facility that is currently under construction and expected to begin commercial operation in the third quarter of 2006.

In addition to new generation resources, substantial transmission investments could be required to deliver power to customers and provide system reliability. The actual investment requirement will depend on the location and other characteristics of the new generation resources. Electric transmission systems deliver energy from electric generators to distribution systems for final delivery to customers.

Transmission and Distribution

PacifiCorp's transmission system is part of the Western Interconnection, the regional grid in the west. 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. 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. Due to PacifiCorp's continuing commitment to improve customer service and network safety and to enhance system reliability and performance, PacifiCorp has focused on infrastructure improvement projects in targeted areas. We and PacifiCorp have committed to a number of transmission and distribution system investments in connection with regulatory approval of PacifiCorp's sale to us.

PacifiCorp operates one control area on the western portion of its service territory and one control area on the eastern portion of its service territory. A control area is a geographic area with electric systems that control generation to maintain schedules with other control areas and ensure reliable operations. In operating the control areas, PacifiCorp is responsible for continuously balancing electric supply and demand by dispatching generating resources and interchange transactions so that generation internal to the control area, plus net import power, matches customer loads. PacifiCorp also schedules power deliveries over its transmission system and maintains reliability in part by verifying that customers are properly using the system within established bounds.

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

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

These services are offered on a non-discriminatory basis, meaning that all potential customers are provided an equal opportunity to access the transmission system. PacifiCorp's transmission business is managed and operated independently from the generating and marketing business in accordance with the FERC Standards of Conduct. Transmission costs are not separated from, but rather are ''bundled'' with, generation and distribution costs in retail rates approved by state regulatory commissions.

The electric transmission distribution system of PacifiCorp at June 30, 2006, included approximately 15,600 miles of transmission lines and approximately 59,500 miles of distribution lines. At June 30, 2006, PacifiCorp owned approximately 900 substations.

MidAmerican Energy

General

MidAmerican Energy, our indirect wholly owned subsidiary, is a public utility company, headquartered in Iowa, which serves approximately 709,000 regulated retail electric customers and approximately 685,000 regulated retail and transportation natural gas customers. MidAmerican Energy is principally engaged in the business of generating, transmitting, distributing and selling electric energy and in distributing, selling and transporting natural gas. MidAmerican Energy distributes electricity at retail in Council Bluffs, Des Moines, Fort Dodge, Iowa City, Sioux City and Waterloo, Iowa; the Quad Cities (Davenport and Bettendorf, Iowa and Rock Island, Moline and East Moline, Illinois); and a number of adjacent communities and areas. It also distributes natural gas at retail in Cedar Rapids, Des Moines, Fort Dodge, Iowa City, Sioux City and Waterloo, Iowa; the Quad Cities; Sioux Falls, South Dakota; and a number of adjacent communities and areas. Additionally, MidAmerican Energy transports natural gas through its distribution system for a number of end-use customers who have independently secured their supply of natural gas. In addition to retail sales and natural gas transportation, MidAmerican Energy sells electric energy and natural gas to other utilities, marketers and municipalities. These sales are referred to as wholesale sales.

MidAmerican Energy's regulated electric and gas operations are conducted under franchise agreements, certificates, permits and licenses obtained from state and local authorities. The franchise agreements, with various expiration dates, are typically for 25-year terms.

Table of Contents

MidAmerican Energy has a diverse customer base consisting of residential, agricultural, and a variety of commercial and industrial customer groups. Among the primary industries served by MidAmerican Energy are those that are concerned with food products, the manufacturing, processing and fabrication of primary metals, real estate, farm and other non-electrical machinery, and cement and gypsum products.

MidAmerican Energy also conducts a number of nonregulated business activities, which include a variety of activities outside of the traditional regulated electric and natural gas services.

MidAmerican Energy derived its operating revenues from the following business activities.

	Years Ended December 31,		
	2005	2004	2003
Regulated electric	47.9%	52.7%	53.9%
Regulated gas	41.8	37.5	36.5
Nonregulated	10.3	9.8	9.6
	100.0%	100.0%	100.0%

Electric Operations

Customers

The percentages of electricity sold (measured in MWh) to retail and wholesale customers, by class of customer, and the total number of retail customers (in thousands) were as follows:

	Years Ended December 31,		
	2005	2004	2003
Residential	21.3%	19.6%	19.4%
Commercial	15.0	14.5	14.0

Industrial	27.9	26.7	25.4
Wholesale	30.5	34.2	36.4
Other	5.3	5.0	4.8
	100.0%	100.0%	100.0%
Total retail customers	706	698	689

The percentages of retail electric operating revenue, by jurisdiction, were as follows:

	Years Ended December 31,		
	2005	2004	2003
Iowa	89.0%	88.7%	88.8%
Illinois	10.1	10.3	10.4
South Dakota	0.9	1.0	0.8
	100.0%	100.0%	100.0%

There are seasonal variations in MidAmerican Energy's electric business that are principally related to the use of electricity for air conditioning. In general, 35-40% of MidAmerican Energy's regulated electric revenues are 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. On July 20, 2005, retail customer usage of electricity caused a new record hourly peak demand of 4,040 MW on MidAmerican Energy's electric system, an increase of 105 MW from the previous record of 3,935 MW set in August 2003.

Table of Contents

Power and Fuel Supply

The following table shows the estimated percentage of MidAmerican Energy's total energy requirements supplied by its generation plants and through short- and long-term contracts or spot market purchases as follows:

	Years Ended December 31,		
	2005	2004	2003
Coal	62.6%	64.4%	65.3%
Nuclear	11.6	11.3	12.1
Wind	2.1	—	—
Natural gas	2.5	0.7	0.4
Other	0.1	0.1	0.1
Total energy generated	78.9	76.5	77.9
Energy purchased – long-term contracts	7.9	12.6	11.5
Energy purchased – other	13.2	10.9	10.6
	100.0%	100.0%	100.0%

The share of MidAmerican Energy's energy requirements generated by its plants will vary from year to year and is determined by factors such as planned and unplanned outages, the availability and price of fuels, weather, environmental considerations and the market price of electricity.

MidAmerican Energy is exposed to fluctuations in energy costs relating to retail sales in Iowa as it does not have an energy adjustment clause. Under its Illinois and South Dakota electric tariffs, MidAmerican Energy is allowed to recover fluctuations in the cost of all fuels and purchased energy used for retail electric generation through a fuel cost adjustment clause.

All of the coal-fired generating stations operated by MidAmerican Energy are fueled by low-sulfur coal from the Powder River Basin in Wyoming. MidAmerican Energy's coal supply portfolio includes multiple suppliers and mines under agreements of varying terms and quantities. MidAmerican Energy typically has one to two years of coal supply under contracts with fixed prices and regularly monitors the western coal market, looking for opportunities to enhance its coal supply portfolio. Operational delays in rail transportation out of the Powder River Basin during 2005 and 2006 resulted in the reduction of coal inventories to suboptimum levels. MidAmerican Energy believes the transportation issues are temporary and that its coal inventories will be restored to preferred levels by late-2007.

MidAmerican Energy has a long-term coal transportation agreement with Union Pacific Railroad Company (or Union Pacific). Under this agreement, Union Pacific delivers coal directly to MidAmerican Energy's Neal and Council Bluffs Energy Centers and to an interchange point with the Iowa, Chicago & Eastern Railroad Corporation for delivery to the Louisa and Riverside Energy Centers. MidAmerican Energy has the ability to use The Burlington Northern and Santa Fe Railway Company for delivery of a small amount of coal to the Council Bluffs, Louisa and Riverside Energy Centers should the need arise.

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 manages its natural gas supply requirements by entering into various financial derivative instruments, including futures, swaps, options and forward physical contracts. Refer to the ''Quantitative and Qualitative Disclosures About Market Risk'' section of this prospectus for a discussion of MidAmerican Energy's derivative instruments.

MidAmerican Energy is a 25% joint owner of Quad Cities Generating Station (or Quad Cities Station), a nuclear power plant. Exelon Generation Company, LLC (or Exelon Generation), the other joint owner and the operator of Quad Cities Station, is a subsidiary of Exelon Corporation. Approximately one-third of the nuclear fuel assemblies in the core at Quad Cities Station Units 1 and 2 are replaced every 24 months. MidAmerican Energy has been advised by Exelon Generation that its uranium requirements for Quad Cities Station through 2008 and part of the requirements through 2011 can be met under existing supplies or commitments. Additionally, under existing supplies and commitments, uranium conversion requirements can be met through 2009 and part of 2010 and enrichment requirements can be met through 2011. Commitments for fuel fabrication have been obtained for the next eight years. MidAmerican Energy has been advised by Exelon Generation that it does not anticipate that it will have difficulty in contracting for uranium, conversion, enrichment or fabrication of nuclear fuel needed to operate Quad Cities Station.

The following table sets out certain information concerning MidAmerican Energy's power generating facilities as of June 30, 2006:

	Location	Energy Source	Installed	Facility Net Capacity (MW)(1)	Net MW Owned(1)
COAL:					
Council Bluffs Unit No. 1	Council Bluffs, IA	Coal	1954	45	45
Council Bluffs Unit No. 2	Council Bluffs, IA	Coal	1958	88	88
Council Bluffs Unit No. 3	Council Bluffs, IA	Coal	1978	690	546
Neal Unit No. 1	Seargent Bluff, IA	Coal	1964	135	135
Neal Unit No. 2	Seargent Bluff, IA	Coal	1972	300	300
Neal Unit No. 3	Seargent Bluff, IA	Coal	1975	515	371
Neal Unit No. 4	Salix, IA	Coal	1979	644	261
Louisa	Muscatine, IA	Coal	1983	700	616
Ottumwa	Ottumwa, IA	Coal	1981	673	350
Riverside Unit No. 3	Bettendorf, IA	Coal	1925	5	5
Riverside Unit No. 5	Bettendorf, IA	Coal	1961	130	130
				3,925	2,847
NATURAL GAS AND OTHER:					
Greater Des Moines	Pleasant Hill, IA	Natural gas/Steam	2003-2004	491	491
Coralville	Coralville, IA	Natural gas/Oil	1970	64	64
Electrifarm	Waterloo, IA	Natural gas/Oil	1975-1978	200	200
Moline	Moline, IL	Natural gas/Oil	1970	64	64
Parr	Charles City, IA	Natural gas/Oil	1969	32	32
Pleasant Hill	Pleasant Hill, IA	Natural gas/Oil	1990-1994	163	163
River Hills	Des Moines, IA	Natural gas/Oil	1966-1967	120	120
Sycamore	Johnston, IA	Natural gas/Oil	1974	149	149
28 portable power modules	Various	Natural gas/Oil	2000	56	56
				1,339	1,339
NUCLEAR PLANTS:					
Quad Cities Unit No. 1	Cordova, IL	Uranium	1972	872	218
Quad Cities Unit No. 2	Cordova, IL	Uranium	1972	876	219
				1,748	437
WIND PLANTS:					
Intrepid	Schaller, IA	Wind	2004-2005	33	33
Century(2)	Blairsburg, IA	Wind	2005	37	0
				70	33
HYDROELECTRIC PLANTS:					
4 hydroelectric plants	Moline, IL	Mississippi River	1970	3	3
Total Available Generating Capacity				7,085	4,659
PROJECTS UNDER CONSTRUCTION:					
Council Bluffs Unit No. 4	Council Bluffs, IA	Coal	N/A	790	479
				7,875	5,138

(1) Facility net capacity (MW) represents total plant accredited net generating capacity from the summer 2005 and the expected accredited generating capacity (MW) of projects recently completed or under construction. Actual MW may vary depending on operating conditions and plant design. Net MW owned indicates MidAmerican Energy's ownership of accredited capacity for the summer of 2005 as approved by the Mid-Continent Area Power Pool (or MAPP).

(2) The Century wind farm was placed in service during the fourth quarter of 2005, which was after the 2005 summer accreditation.

Future Generation

MidAmerican Energy anticipates a continuing increase in demand for electricity from its regulated customers. To meet anticipated demand and ensure adequate electric generation in its service territory, MidAmerican Energy is currently constructing CBEC Unit 4, a 790-MW (expected accreditation) super-critical-temperature, coal-fired generating plant. MidAmerican Energy will operate the plant and hold an undivided ownership interest as a tenant in common with the other owners of the plant. MidAmerican Energy's current ownership interest is 60.67%, equating to 479 MW of output. Municipal, cooperative and public power utilities will own the remainder, which is a typical ownership arrangement for large base-load plants in Iowa. The facility will provide service to regulated retail electricity customers. Wholesale sales may also be made from the facility to the extent the power is not immediately needed for regulated retail service. MidAmerican Energy has obtained regulatory approval to include the Iowa portion of the actual cost of the generation project in its Iowa rate base as long as the actual cost does not exceed the agreed cap that MidAmerican Energy has deemed to be reasonable. If the cap is exceeded, MidAmerican Energy has the right to demonstrate the prudence of the expenditures above the cap, subject to regulatory review. MidAmerican Energy expects to invest approximately $737 million in CBEC Unit 4, including transmission facilities and excluding allowance for funds used during construction. Through June 30, 2006, MidAmerican Energy has invested $594.0 million in the project, including $121.3 million for MidAmerican Energy’s share of deferred payments allowed by the construction contract.

On December 16, 2005, MidAmerican Energy filed with the IUB a settlement agreement between MidAmerican Energy and the OCA regarding rate-making principles for up to 545 MW (nameplate ratings) of wind-powered generation capacity in Iowa to be installed in 2006 and 2007. Generally speaking, accredited capacity ratings for wind power facilities are considerably less than the nameplate ratings due to the varying nature of wind. The settlement agreement was approved by the IUB on April 18, 2006. MidAmerican Energy has entered into agreements for the construction of approximately 99 MW (nameplate ratings) of wind-powered generation capacity to be completed by the end of 2006 and for the construction of approximately 123 MW (nameplate ratings) of wind-powered generation capacity to be completed by the end of 2007. The second agreement also provides for the sale of development rights to an adjacent project whose size could be up to 77 MW (nameplate ratings). Refer to the ‘‘Regulation’’ section of this prospectus for more information regarding the rate aspects of the settlement agreement.

Transmission and Distribution

MidAmerican Energy is interconnected with Iowa utilities and utilities in neighboring states. MidAmerican Energy is also party to an electric generation reserve sharing pool and regional transmission group administered by the MAPP. The MAPP is a voluntary association of electric utilities doing business in Minnesota, Nebraska, North Dakota and the Canadian provinces of Saskatchewan and Manitoba and portions of Iowa, Montana, South Dakota and Wisconsin. Its membership also includes power marketers, regulatory agencies and independent power producers. The MAPP performs functions including administration of its short-term regional OATT, coordination of regional planning and operations, and operation of the generation reserve sharing pool.

MidAmerican Energy's transmission system connects its generating facilities with distribution substations and interconnects with 14 other transmission providers in Iowa and five adjacent states. Under normal operating conditions, MidAmerican Energy's transmission system has adequate capacity to deliver energy to MidAmerican Energy's distribution system and to export and import energy with other interconnected systems. The electric transmission system of MidAmerican Energy at June 30, 2006, included approximately 900 miles of 345-kV lines and approximately 1,100 miles of 161-kV lines. MidAmerican Energy's electric distribution system included approximately 227,000 transformers and approximately 400 substations at June 30, 2006.

Natural Gas Operations

MidAmerican Energy is engaged in the procurement, transportation, storage and distribution of natural gas for customers in the Midwest. MidAmerican Energy purchases natural gas from various

suppliers, transports it from the production area to MidAmerican Energy's service territory under contracts with interstate pipelines, stores it in various storage facilities to manage fluctuations in system demand and seasonal pricing, and distributes it to customers through MidAmerican Energy's distribution system.

MidAmerican Energy sells natural gas and transportation services to end-use, or retail, customers and natural gas to other utilities, marketers and municipalities. MidAmerican Energy also transports through its distribution system natural gas purchased independently by a number of end-use customers. During 2005, 46% of total natural gas delivered through MidAmerican Energy's system for end-use customers was under natural gas transportation service.

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

The percentage of regulated natural gas revenue, excluding transportation throughput, by customer class follows:

	Years Ended December 31,		
	2005	**2004**	**2003**
Residential	37.5%	40.0%	44.1%
Small general service(1)	18.2	19.6	21.0
Large general service(1)	4.1	2.2	1.9
Wholesale(2)	40.2	38.0	32.7
Other	—	0.2	0.3
	100.0%	100.0%	100.0%

(1) Small and large general service customers are classified primarily based on the nature of their business and gas usage. Small general service customers are business customers whose gas usage is principally for heating. Large general service customers are business customers whose principal gas usage is for their manufacturing processes.

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

The percentage of regulated natural gas revenue, excluding transportation throughput, by jurisdiction follows:

	Years Ended December 31,		
	2005	**2004**	**2003**
Iowa	77.4%	77.7%	77.9%
South Dakota	11.7	11.5	11.3
Illinois	10.0	9.9	10.0
Nebraska	0.9	0.9	0.8
	100.0%	100.0%	100.0%

MidAmerican Energy purchases natural gas supplies from producers and third-party marketers. To enhance system reliability, a geographically diverse supply portfolio with varying terms and contract conditions is utilized for the natural gas supplies. MidAmerican Energy attempts to optimize the value of its regulated assets by engaging in wholesale sales transactions. IUB and SDPUC rulings have allowed MidAmerican Energy to retain 50% of the respective jurisdictional margins earned on wholesale sales of natural gas, with the remaining 50% being returned to customers through the purchased gas adjustment clauses discussed below.

MidAmerican Energy has rights to firm pipeline capacity to transport natural gas to its service territory through direct interconnects to the pipeline systems of Northern Natural Gas (an affiliate company), Natural Gas Pipeline Company of America (or NGPL), Northern Border Pipeline

Company (or Northern Border) and ANR Pipeline Company (or ANR). At times, the capacity available through MidAmerican Energy's firm capacity portfolio may exceed the demand on MidAmerican Energy's distribution system. Firm capacity in excess of MidAmerican Energy's system needs can be resold to other companies to achieve optimum use of the available capacity. Past IUB and SDPUC rulings have allowed MidAmerican Energy to retain 30% of the respective jurisdictional margins earned on the resold capacity, with the remaining 70% being returned to customers through the purchased gas adjustment clauses.

MidAmerican Energy is allowed to recover its cost of natural gas from all of its regulated natural gas customers through purchased gas adjustment clauses. 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 to reduce the market price risk for its natural gas customers, including the use of storage gas and peak-shaving facilities, sharing arrangements to share savings and costs with customers and short-term and long-term financial and physical gas purchase agreements.

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 withdrawn during periods of peak demand and 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 three liquefied natural gas (or LNG) plants and two propane-air plants 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.

In 1995, the IUB gave initial approval of MidAmerican Energy's Incentive Gas Supply Procurement Program. In November 2004, the IUB extended the program through October 31, 2006. Under the program, as amended, MidAmerican Energy is required to file with the IUB every six months a comparison of its natural gas procurement costs to a reference price. If MidAmerican Energy's cost of natural gas for the period is less or greater than an established tolerance band around the reference price, then MidAmerican Energy shares a portion of the savings or costs with customers. A similar program is currently in effect in South Dakota through October 31, 2010. Since the implementation of the program, MidAmerican Energy has successfully achieved and shared savings with its natural gas customers.

On February 2, 1996, MidAmerican Energy had its highest peak-day delivery of 1,143,026 Dth. This peak-day delivery consisted of 88% traditional sales service and 12% transportation service of customer-owned gas. As of June 30, 2006, MidAmerican Energy's 2005/2006 winter heating season peak-day delivery of 1,004,109 Dth was reached on February 17, 2006. This peak-day delivery included 74% traditional sales service and 26% transportation service.

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 at June 30, 2006, included approximately 22,000 miles of gas mains and services pipelines.

Interstate Pipeline Companies

Kern River

Kern River, our indirect wholly owned subsidiary, was acquired by us in March 2002 and owns an interstate natural gas transportation pipeline system comprising 1,679 miles of pipeline, with an approximate design capacity of 1,755,575 Dth per day, extending from supply areas in the Rocky Mountains to consuming markets in Utah, Nevada, Arizona and California. On May 1, 2003, Kern River placed into service a 717-mile expansion project (or the 2003 Expansion Project), which increased the design capacity of Kern River's pipeline system by 885,575 Dth per day to its current

1,755,575 Dth per day. 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 FERC-regulated tariff that is designed to allow it an opportunity to recover its costs together with a regulated return on equity.

Kern River's pipeline consists of two sections: the mainline section and the common facilities. Kern River owns the entire mainline section, which extends from the pipeline's point of origination near Opal, Wyoming through the central Rocky Mountains area into Daggett, California. The mainline section consists of the original 682 miles of 36-inch diameter pipeline, 628 miles of 36-inch diameter loop pipeline related to the 2003 Expansion Project and 68 miles of various laterals that connect to the mainline.

The common facilities consist of a 219-mile section of original pipeline that extends from the point of interconnection with the mainline in Daggett to Bakersfield, California and an additional 82 miles related to the 2003 Expansion Project. The common facilities are jointly owned by Kern River (approximately 76.8% as of June 30, 2006) and Mojave Pipeline Company (or Mojave), a wholly owned subsidiary of El Paso Corporation (or El Paso), (approximately 23.2% as of June 30, 2006) 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 approximately 1,570,500 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.

As of June 30, 2006, Kern River had 1,661,575 Dth per day of capacity under long-term firm natural gas transportation service agreements pursuant to which 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.

With respect to Kern River's mainline facilities in existence prior to the 2003 Expansion Project, at June 30, 2006, Kern River had 28 long-term firm natural gas transportation service agreements with 16 shippers, for a total of 848,949 Dth per day of capacity. These long-term firm natural gas transportation service agreements expire between September 30, 2011 and April 30, 2018. Several of these shippers are major oil and gas companies or affiliates of such companies. These shippers also include electric generating companies, energy marketing and trading companies, and a natural gas distribution utility which provides services in Nevada and California.

With respect to Kern River's 2003 Expansion Project, at June 30, 2006, Kern River had 19 long-term firm natural gas transportation service agreements with 16 shippers, for a total of 812,626 Dth per day of capacity from the pipeline's point of origination near Opal, Wyoming to delivery points primarily in California. As of June 30, 2006, approximately 83% of the 2003 Expansion Project's capacity is contracted for 15 years, with 14 of the long-term firm natural gas transportation service agreements expiring on April 30, 2018. The remaining 17% of capacity is contracted for 10 years, with five long-term firm natural gas transportation service agreements expiring on April 30, 2013. As of June 30, 2006, over 95% of the 2003 Expansion Project's capacity has primary delivery points in California, with the flexibility to access secondary delivery points in Nevada and Utah. Kern River has an additional 94,000 Dth per day of available firm capacity associated with the 2003 Expansion Project that was recently sold to a number of shippers at a discounted daily demand rate for the period of April 2006 through September 2008 on a short-term basis. Kern River will continue to market this capacity or use it for any future expansion needs for any period beyond September 2008.

Calpine Corp., including Calpine Energy Services, L.P. (or Calpine), filed for Chapter 11 bankruptcy protection on December 20, 2005. Calpine holds two 50,000 Dth per day incremental 2003 Expansion Project firm transportation contracts that have termination dates of April 30, 2018. Pursuant to Kern River's credit requirements, Calpine provided approximately $19 million as cash

security for the transportation contracts, with approximately $3 million being applied against Calpine’s pre-petition invoices. Post-petition, to date, Calpine has continued to nominate on its transportation contracts and pay its post-petition invoices; however, Calpine has indicated that it has not yet determined whether it will assume or reject the transportation contracts. Calpine has represented that any replenishment of collateral that it makes will be applied only to post-petition invoices. Calpine has yet to replenish the collateral for its Kern River contracts.

Northern Natural Gas

Northern Natural Gas, our indirect wholly owned subsidiary, was acquired by us in August 2002 and owns one of the largest interstate natural gas pipeline systems in the United States. It reaches from Texas to Michigan’s Upper Peninsula and is engaged in the transmission and storage of natural gas for utilities, other pipeline companies, gas marketers, industrial and commercial users and other end users. Northern Natural Gas operates approximately 15,900 miles of natural gas pipelines, consisting of approximately 6,800 miles of mainline transmission pipelines and approximately 9,100 miles of lateral pipelines, with a design capacity of 4.6 Bcf per day. Based on a review of relevant 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. Northern Natural Gas’ revenue is derived from the interstate transportation and storage of natural gas for third parties. Except for small quantities of natural gas owned for system operations, Northern Natural Gas does not own the natural gas that is transported through its system. Northern Natural Gas’ transportation and storage operations are subject to a FERC-regulated tariff that is designed to allow it an opportunity to recover its costs together with a regulated return on equity.

Northern Natural Gas’ system consists of two distinct but operationally integrated markets. Its traditional end-use and distribution market area is at the northern end of the system, including delivery points in Michigan, Illinois, Iowa, Minnesota, Nebraska, Wisconsin and South Dakota, which Northern Natural Gas refers to as the Market Area, and the natural gas supply and service area is at the southern end of the system, including Kansas, Oklahoma, Texas and New Mexico, which Northern Natural Gas refers to as the Field Area. Northern Natural Gas’ Field Area is interconnected with many interstate and intrastate pipelines in the national grid system. A majority of Northern Natural Gas’ capacity in both the Market Area and the Field Area is dedicated to Market Area customers under long-term firm transportation contracts. As of June 30, 2006, approximately 57% of Northern Natural Gas’ firm transportation capacity in the Market Area is contracted beyond 2008 and approximately 39% of such capacity is contracted beyond 2015.

Northern Natural Gas’ pipeline system transports natural gas primarily to end-user and local distribution markets in the Market Area. Customers consist of LDCs, municipalities, other pipeline companies, gas marketers and end-users. While eight large LDCs account for the majority of Market Area volumes, Northern Natural Gas also serves numerous small communities through these large LDCs as well as municipalities or smaller LDCs and directly serves several large end-users. In 2005, over 85% of Northern Natural Gas' transportation and storage revenue was from capacity charges under firm transportation and storage contracts and approximately 80% of that revenue was from LDCs. In 2005, approximately 71% of Northern Natural Gas' transportation and storage revenue was generated from Market Area customer contracts.

The Field Area of Northern Natural Gas' system provides access to natural gas supply from key production areas including the Hugoton, Permian and Anadarko Basins. In each of these areas, Northern Natural Gas has numerous interconnecting receipt and delivery points, with volumes received in the Field Area consisting of both directly connected supply and volumes from interconnections with other pipeline systems. In addition, Northern Natural Gas has the ability to aggregate processable natural gas for deliveries to various gas processing facilities.

In the Field Area, customers holding transportation capacity consist of LDCs, marketers, producers, and end-users. The majority of Northern Natural Gas' Field Area firm transportation is provided to Northern Natural Gas' Market Area firm customers under long-term firm transportation contracts with such volumes supplemented by volumes transported on an interruptible basis or

pursuant to short-term firm contracts. In 2005, approximately 19% 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 storage field in Iowa, two underground storage facilities in Kansas and one LNG storage peaking unit each in Garner, Iowa and Wrenshall, Minnesota. The three underground natural gas storage facilities and Northern Natural Gas' two LNG storage peaking units have a total firm service storage capacity of approximately 59 Bcf and over 1.3 Bcf per day of peak day deliverability. These storage facilities provide Northern Natural Gas with operational flexibility for the daily balancing of its system and providing services to customers for meeting their year-round load requirements. In 2005, approximately 10% of Northern Natural Gas' transportation and storage revenue was generated from storage services.

Northern Natural Gas' system experiences significant seasonal swings in demand, with the highest demand occurring during the months of November through March. The seasonality provides Natural Gas opportunities to deliver high value added services, such as firm and interruptible storage services, as well as no notice services, particularly during the lower demand months. Because of its location and multiple interconnections with other interstate and intrastate pipelines, Northern Natural Gas is able to access natural gas both from traditional production areas, such as the Hugoton, Permian and Anadarko Basins, as well as growing supply areas such as the Rocky Mountains through Trailblazer Pipeline Company, Pony Express Pipeline and Colorado Interstate Gas Pipeline Company, or Colorado Interstate, and from Canadian production areas through Northern Border, Great Lakes Gas Transmission Limited Partnership, or Great Lakes and Viking Gas Transmission Company, or Viking. 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 augments its steady end-user and LDC revenue by taking advantage of opportunities to provide intermediate transportation through pipeline interconnections for customers in other markets including Chicago, Illinois, other parts of the Midwest and Texas.

Kern River and Northern Natural Gas 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, location and overall customer service. Industrial end-users often have the ability to choose from alternative fuel sources in addition to natural gas, such as fuel oil and coal. Natural gas competes with other forms of energy, including electricity, coal and fuel oil, primarily on the basis of price. Legislation and governmental regulations, the weather, the futures market, production costs, and other factors beyond the control of Kern River and Northern Natural Gas influence the price of natural gas.

Kern River competes with various interstate pipelines and its shippers in order to market any unutilized or unsubscribed capacity serving the southern California, Las Vegas, Nevada and Salt Lake City, Utah market areas. Kern River provides its customers with supply diversity through pipeline interconnections with Northwest Pipeline, Colorado Interstate, Overland Trail Pipeline, and Questar Pipeline. 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 into the intrastate California market. This enables direct 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 to economic Rocky Mountain gas reserves increases its competitiveness and attractiveness to end-users. Kern River believes it is advantaged relative to other competing interstate pipelines because its relatively new pipeline can be expanded at comparatively lower costs and will require significantly less capital expenditure to comply with the PSIA than other systems. Kern River's levelized rate structures have been challenged in its 2004 general rate case. Certain parties have advocated converting the system to a traditional declining rate base structure. Kern River's favorable market position is tied to the availability and 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 addition, Kern River's 2003 Expansion Project relies substantially on long-term transportation service agreements with several electric generation companies, which face significant competitive and financial pressures due to, among other things, the financial stress of energy markets and apparent over-building of electric generation capacity in California and other markets. This condition is expected to ease over time as demand for electric generation in Kern River's market territory increases and older, less efficient power plants in the region are retired.

Northern Natural Gas has been able to provide competitive cost service because of its access to a variety of relatively low cost gas supply basins, its cost control measures and its competitive load factor throughput, which lowers the cost per unit of transportation. Although Northern Natural Gas has periodically experienced bypass of the pipeline system affecting a small percentage of its market, to date Northern Natural Gas has been able to more than offset any load lost to bypass in the Northern Natural Gas Market Area through expansion projects.

Major competitors in the Northern Natural Gas Market Area include: ANR, Northern Border and NGPL. Other competitors include Great Lakes and Viking. In the Field Area, Northern Natural Gas competes with a large number of other competitors. Particularly in the Field Area, a significant amount of Northern Natural Gas' capacity is used on an interruptible or short-term basis. In summer months, Northern Natural Gas' Market Area customers often release significant amounts of their unused firm capacity to other shippers, which released capacity competes with Northern Natural Gas' short-term or interruptible services.

Although Northern Natural Gas will need to aggressively compete to retain and build load, Northern Natural Gas believes that current and anticipated changes in its competitive environment have created opportunities to serve existing customers more efficiently and to meet certain growing supply needs. While LDCs' peak day growth is driven by population growth and alternative fuel replacement, new off-peak demand growth is being driven primarily by power and ethanol plant expansion. Off-peak demand growth is important to Northern Natural Gas as this demand can generally be satisfied with little or no requirement for the construction of new facilities. Northern Natural Gas has been successful in competing for a significant amount of the increased demand related to the electric generation and ethanol plants. Over the last five years, Northern Natural Gas has contracted approximately 319 MMcf per day of firm volume on its system from such new facilities, of which approximately 255 MMcf per day is currently in service and approximately 64 MMcf per day is scheduled to begin service in 2006. The passage of the Energy Policy Act has continued to encourage ethanol development and has had a positive effect of increasing demand on Northern Natural Gas' system.

In 2005, Kern River had one customer who accounts for greater than 10% of its revenue and Northern Natural Gas had two customers who each account for greater than 10% of its revenue. Northern Natural Gas has agreements to retain the vast majority of both of these customers' volumes through at least 2017. The loss of any one or more of these customers, if not replaced, could have a material adverse effect on Kern River's and Northern Natural Gas' respective businesses.

CE Electric UK

CE Electric UK, our indirect wholly owned subsidiary, owns, primarily, two companies that distribute electricity in Great Britain. Northern Electric and Yorkshire Electricity, together, constitute the third-largest distributor in Great Britain, serving more than 3.7 million customers in an area of approximately 10,000 square miles.

Electricity Distribution

Northern Electric and Yorkshire Electricity's operations consist primarily of the distribution of electricity in the United Kingdom. Northern Electric and Yorkshire Electricity receive electricity from the national grid transmission system and distribute it to their customers' premises using their network

of transformers, switchgear and cables. Substantially all of the end users in Northern Electric and Yorkshire Electricity's distribution service areas are connected to the Northern Electric and Yorkshire Electricity's networks and electricity can only be delivered through their distribution system, thus providing Northern Electric and Yorkshire Electricity with distribution volume that is relatively stable from year to year. Northern Electric and Yorkshire Electricity charge fees for the use of the distribution system to the suppliers of electricity. The suppliers, which purchase electricity from generators and sell the electricity to end-user customers, use Northern Electric and Yorkshire Electricity distribution networks pursuant to an industry standard ''Distribution Use of System Agreement'' which Northern Electric and Yorkshire Electricity separately entered into with the various suppliers of electricity in their respective distribution areas. One such supplier, Npower and certain of its affiliates, represented approximately 44% of the total revenues of Northern Electric and Yorkshire Electricity in 2005. The fees that may be charged by Northern Electric and Yorkshire Electricity for use of their distribution systems are controlled by a formula prescribed by the UK's electricity regulatory body that limits increases (and may require decreases) based upon the rate of inflation in the United Kingdom and other regulatory action.

At June 30, 2006, Northern Electric and Yorkshire Electricity's electricity distribution network (excluding service connections to consumers) on a combined basis included approximately 33,000 kilometers of overhead lines and approximately 65,000 kilometers of underground cables. In addition to the circuits referred to above, at June 30, 2006, Northern Electric's and Yorkshire Electricity's distribution facilities also included approximately 60,000 transformers and approximately 700 primary substations. Substantially all substations are owned, with the balance being leased from third parties, most of which have remaining terms of at least 10 years.

Utility Services

Integrated Utility Services Limited CE Electric UK's indirect wholly owned subsidiary, is an engineering contracting company providing electrical infrastructure contracting services to third parties.

Gas Exploration and Production

CE Gas, CE Electric UK's indirect wholly owned subsidiary, is a gas exploration and production company that is focused on developing integrated upstream gas projects in Australia, the United Kingdom and Poland. Its upstream gas business consists of exploration, development and production projects, resulting in the sale of gas to third parties.

In Australia, CE Gas has construction and development projects in the Bass, Otway and Perth Basins. The Yolla construction project in the Bass Basin is a gas and gas liquids project in which CE Gas holds a 15% interest. The project, operated by Origin Energy Resources Limited of Australia, is now in production and includes an approximately 145 kilometer sub-sea pipeline across the Bass Strait off southern Victoria. The gas from the project is being sold to Origin Energy Resources Limited of Australia's retail affiliate, the liquefied petroleum gas is being sold to Elgas Limited, the largest marketer of liquefied petroleum gas in Australia, and the condensate is being sold to The Shell Company of Australia Limited. The Otway Gas Project, in which CE Gas holds a 5% interest, is operated by Woodside Exploration Limited of Australia. Construction began in 2004 and first production is expected in early 2007.

In the United Kingdom, CE Gas continues to retain its 5% interest in the Victor Field, which is a gas field, located in the Southern North Sea. CE Gas is also developing certain new exploration in the North Sea.

CalEnergy Generation – Foreign

The CalEnergy Generation-Foreign platform consists of our indirect ownership of the Leyte Projects, which are geothermal power plants located on the island of Leyte in the Philippines, and a combined irrigation and hydroelectric power generation project located in the central part of the

Table of Contents

island of Luzon in the Philippines (or the Casecnan Project). Each plant possesses an operating margin that allows for production in excess of the amount listed below. Utilization of this operating margin is based upon a variety of factors and can be expected to vary between calendar quarters under normal operating conditions.

The following table sets out certain information concerning CalEnergy Generation-Foreign's non-utility power projects in operation as of June 30, 2006:

Project(1)	Facility Net Capacity (MW)(2)	Net MW Owned(2)	Energy Source	Contract Expiration	Power Purchaser/ Guarantor(3)
Mahanagdong	154	150	Geo	July 2007	PNOC-EDC/ROP
Malitbog	216	216	Geo	July 2007	PNOC-EDC/ROP
Casecnan(4)	150	150	Water	December 2021	NIA/ROP
Total	520	516			

(1) All projects are located in the Philippines and carry political risk insurance.

(2) Actual MW may vary depending on operating, geothermal reservoir and water flow conditions, as well as plant design. Facility Net Capacity (MW) represents the contract capacity for the facility. Net MW Owned indicates current legal ownership, but, in some cases, does not reflect the current allocation of distributions.

(3) NIA also pays CE Casecnan, our indirect subsidiary, for the delivery of water and electricity by CE Casecnan. Separate sovereign performance undertakings of the ROP support PNOC-EDC's obligations for the Leyte Projects. The ROP has also provided a performance undertaking under which NIA's obligations under the Casecnan Project agreement, as supplemented by the Supplemental Agreement, are guaranteed by the full faith and credit of the ROP.

(4) Net MW Owned of approximately 150 MW is subject to repurchase rights of up to 15% of the project by an initial minority shareholder and a dispute with the other initial minority shareholder regarding an additional 15% of the project. Refer to the ''Legal Proceedings'' section of this prospectus for additional information.

PNOC-EDC's and NIA's obligations under the project agreements are substantially denominated in U.S. dollars and are the Leyte Projects' and Casecnan Project'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 agreements 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.

CE Cebu Geothermal Power Company, Inc., a Philippine corporation that is 100% indirectly owned by us, had previously owned and operated the Upper Mahiao project, a 119-net MW geothermal power project. On June 25, 2006, the end of the 10-year cooperation period, the Upper Mahiao facility was transferred to PNOC-EDC at no cost on an ''as-is'' basis.

The Mahanagdong and Malitbog projects take geothermal steam and fluid, provided at no cost by PNOC-EDC, and convert their thermal energy into electrical energy which is sold to PNOC-EDC, which in turn sells the power to the National Power Corporation (or NPC), the government-owned and controlled corporation that is the primary supplier of electricity in the Philippines, for distribution on the islands of Cebu and Luzon. Payments under the Mahanagdong and Malitbog agreements are denominated in U.S. dollars, or computed in U.S. dollars and paid in pesos at the then-current exchange rate, except for the energy fees discussed below.

The Mahanagdong project is a 154-net MW geothermal power project owned and operated by CE Luzon Geothermal Power Company, Inc. (or CE Luzon), a Philippine corporation of which we indirectly own 100% of the common stock. Another industrial company owns an approximate 3%

preferred equity interest in the Mahanagdong project. The Mahanagdong project sells 100% of its capacity to PNOC-EDC, which in turn sells the power to the NPC for distribution on the island of Luzon.

On July 25, 2007, the end of the 10-year cooperation period, the Mahanagdong facility will be transferred to PNOC-EDC at no cost on an ‘‘as-is’’ basis. PNOC-EDC pays CE Luzon a fee based on the plant capacity. Pursuant to an amendment to the Mahanagdong energy conversion agreement dated August 31, 2003, CE Luzon and PNOC-EDC agreed that the plant capacity would equal the contractually specified level, which declines from approximately 154 MW in 2005 to approximately 153 MW in the last year of the cooperation period. In 2005, the capacity fees were approximately 99% of total revenue at the contractually agreed capacity levels and the energy fees were approximately 1% of such total revenue.

The Malitbog project is a 216-net MW geothermal project owned and operated by Visayas Geothermal Power Company (or VGPC), a Philippine general partnership that is indirectly wholly owned by us. VGPC sells 100% of its capacity to PNOC-EDC, which in turn sells the power to the NPC for distribution on the islands of Cebu and Luzon.

The Malitbog energy conversion agreement 10-year cooperation period expires on July 25, 2007, at which time the facility will be transferred to PNOC-EDC at no cost on an ‘‘as-is’’ basis. In 2005, capacity payments under the agreement equaled 100% of total revenue. Pursuant to an amendment to the Malitbog energy conversion agreement dated August 31, 2003, VGPC and PNOC-EDC agreed that the plant capacity would equal the contractually specified level of 216 MW. A substantial majority of the capacity payments are required to be made by PNOC-EDC in U.S. dollars. The portion of capacity payments payable to PNOC-EDC in pesos is expected to vary over the term of the Malitbog project energy conversion agreement from 10% of VGPC’s revenue in the early years of the cooperation period to 23% of VGPC’s revenue at the end of the cooperation period. Payments made in pesos are generally made to a peso-denominated account and are used to pay peso-denominated expenses with respect to the Malitbog project.

The Casecnan Project is a combined irrigation and hydroelectric power generation project. The Casecnan Project consists generally of diversion structures in the Casecnan and Taan rivers that capture and divert excess water in the Casecnan watershed by means of concrete, in-stream diversion weirs and transfer that water through a transbasin tunnel of approximately 23 kilometers. During the water transfer, the elevation differences between the two watersheds allows electrical energy to be generated at an approximately 150-MW rated capacity power plant, which is located in an underground powerhouse cavern at the end of the transbasin water tunnel. A tailrace discharge tunnel then delivers water to the existing underutilized water storage reservoir at Pantabangan, providing additional water for irrigation and increasing the potential electrical generation at two existing downstream hydroelectric facilities of NPC. Once in the reservoir at Pantabangan, the water is under the control of NIA.

CE Casecnan owns and operates the Casecnan Project under the terms of the Project Agreement between CE Casecnan and NIA, which was modified by a Supplemental Agreement between CE Casecnan and NIA effective on October 15, 2003 (or the Supplemental Agreement). CE Casecnan will own and operate the project for a 20-year cooperation period which commenced on December 11, 2001, the start of the Casecnan Project’s commercial operations, 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 dependant 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 may have a material impact on the amounts 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 (described below) can produce significant variability in revenue between reporting periods.

Under the Supplemental Agreement, CE Casecnan is paid a fee for the delivery of water and a fee for the generation of electricity. With respect to water deliveries, the water delivery fee is payable in a fixed monthly payment based upon an average annual water delivery of 801.9 million cubic

meters, pro-rated to approximately 66.8 million cubic meters per month, multiplied by the applicable per cubic meter rate through December 25, 2008. For each contract year starting from December 25, 2003, and ending on December 25, 2008, a water delivery credit (deferred revenue) is computed equal to 801.9 million cubic meters minus the greater of actual water deliveries or 700.0 million cubic meters – the minimum threshold. The water delivery credit at the end of the contract year is available to be earned in the succeeding contract years ending December 25, 2008. The cumulative water delivery credit at December 25, 2008, if any, shall be amortized from December 25, 2008 through December 25, 2013. Accordingly, in recognizing revenue, the water delivery fees are recorded each month pro-rated to approximately 58.3 million cubic meters per month until the minimum threshold has been reached for the contract year. Subsequent water delivery fees within the contract year are based on actual water delivered.

With respect to electricity, CE Casecnan is paid a guaranteed energy delivery fee each month equal to the product obtained by multiplying 19 GWh times $0.1596 per kWh. The guaranteed energy delivery fee is payable regardless of the amount of energy actually generated and delivered by CE Casecnan in any month. NIA also pays CE Casecnan an excess energy delivery fee, which is a variable amount based on actual electrical energy, if any, delivered in each month in excess of 19 GWh multiplied by (i) $0.1509 per kWh through the end of 2008 and (ii) commencing in 2009, $0.1132 (escalating at 1% per annum thereafter) per kWh, provided that any deliveries of energy in excess of 490 GWh but less than 550 GWh per year are paid for at a rate of 1.3 pesos per kWh and deliveries in excess of 550 GWh per year are at no cost to NIA. Within each contract year, no variable energy fees are payable until energy in excess of the cumulative 19 GWh per month for the contract year to date has been delivered. If the Casecnan Project is not dispatched up to 150 MW whenever water is available, NIA will pay for energy that could have been generated but was not as a result of such dispatch constraint.

In connection with the signing of the Supplemental Agreement, CE Casecnan received written confirmation from the Private Sector Assets and Liabilities Management Corporation that the issues with respect to the Casecnan Project that had been raised by the interagency review of independent power producers in the Philippines or that may have existed with respect to the project under certain provisions of the Electric Power Industry Reform Act of 2001 (or EPIRA), which authorized the ROP to seek to renegotiate certain contracts such as the Project Agreement, have been satisfactorily addressed by the Supplemental Agreement.

CalEnergy Generation – Domestic

The subsidiaries comprising our CalEnergy Generation-Domestic platform own interests in 15 operating 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 June 30, 2006:

Operating Project	Facility Net Capacity (MW)(1)	Net MW Owned(1)	Energy Source	Location	Power Purchase Agreement Expiration	Power Purchaser(2)
Cordova	537	537	Gas	Illinois	2019	Constellation
Wailuku	10	5	Hydro	Hawaii	2023	HELCO
CE Generation:(3)						
Geothermal –						
Salton Sea I	10	5	Geo	California	2017	Edison
Salton Sea II	20	10	Geo	California	2020	Edison
Salton Sea III	50	25	Geo	California	2019	Edison
Salton Sea IV	40	20	Geo	California	2026	Edison
Salton Sea V	49	25	Geo	California	Varies	Various
Vulcan	34	17	Geo	California	2016	Edison
Elmore	38	19	Geo	California	2018	Edison
Leathers	38	19	Geo	California	2019	Edison
Del Ranch	38	19	Geo	California	2019	Edison
CE Turbo	10	5	Geo	California	2029	APS
	327	164				
Natural-Gas Fired –						
Saranac	240	90	Gas	New York	2009	NYSE&G
Power Resources	212	106	Gas	Texas	N/A	Market sales
Yuma	50	25	Gas	Arizona	2024	SDG&E
	502	221				
	829	385				
Total	1,376	927				

(1) Represents nominal net generating capability (accredited for Cordova and contract capacity for most others). Actual MW may vary depending on operating and reservoir conditions and plant design. Net MW Owned indicates current legal ownership, but, in some cases, does not reflect the current allocation of partnership distributions.

(2) Constellation Energy Commodities Group (or Constellation); Hawaii Electric Company (or HELCO); Southern California Edison Company (or Edison); Arizona Public Service (or APS); New York State Electric & Gas Corporation (or NYSE&G); and San Diego Gas & Electric Company (or SDG&E).

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

Cordova Energy owns a 537-MW gas-fired power plant in the Quad Cities, Illinois area (or the Cordova Project). CalEnergy Generation Operating Company, our indirect wholly owned subsidiary, operates the Cordova Project which commenced commercial operations in June 2001. On July 6, 1999, Cordova Energy entered into a power purchase agreement with a unit of El Paso, under which El Paso was obligated to purchase all of the capacity and energy generated from the project until December 31, 2019. Effective January 1, 2006, El Paso assigned all of its rights and obligations under

the power purchase agreement to Constellation. In connection with the assignment, Constellation Energy Group, Inc., the ultimate parent of Constellation, issued a limited guarantee of Constellation's obligations under the power purchase agreement. The contract year under the power purchase agreement extends from May 15th in a year to May 14th in the subsequent year. For each contract year, Cordova Energy has an option to recall 50% of the output of the Cordova Project.

Each of the Imperial Valley Projects, excluding the Salton Sea V and CE Turbo projects, sells electricity to Edison pursuant to a separate Standard Offer No. 4 Agreement (or SO4 Agreement) or a negotiated power purchase agreement. Each power purchase agreement is independent of the others, and the performance requirements specified within one such agreement apply only to the project subject to the agreement. The power purchase agreements provide for capacity payments, capacity bonus payments and energy payments. Edison makes fixed annual capacity payments and capacity bonus payments to the applicable projects to the extent that capacity factors exceed certain benchmarks. The price for capacity is fixed for the life of the SO4 Agreements and is significantly higher in the months of June through September.

Energy payments under the original SO4 Agreements were based on the cost that Edison avoids by purchasing energy from the project instead of obtaining the energy from other sources (or Avoided Cost of Energy). In June and November 2001, the Imperial Valley Projects (except the Salton Sea IV Project, which remained on Edison's Avoided Cost of Energy) which receive Edison's Avoided Cost of Energy entered into agreements that provide for amended energy payments under the SO4 Agreements. The amendments provide for fixed energy payments per kWh in lieu of Edison's Avoided Cost of Energy. The fixed energy payment was 3.25 cents per kWh from December 1, 2001 through April 30, 2002 and is 5.37 cents per kWh from May 1, 2002 through April 30, 2007. In May 2006, these same projects entered into agreements that provide for amended energy payments under the SO4 Agreements during the period May 1, 2007 through April 30, 2012. The amendments, which are subject to the approval of the CPUC, provide for a fixed energy price during this five-year period of 6.15 cents per kWh, escalated 1% annually beginning May 1, 2008. The current energy price of 5.37 cents per kWh, established in 2001, will remain in effect through April 30, 2007. Edison filed an advice letter with the CPUC on July 28, 2006, seeking approval of the amendments in November 2006. The CPUC is under no formal schedule to approve the amendments. For the years ended December 31, 2005, 2004 and 2003, Edison's average Avoided Cost of Energy was 7.7 cents per kWh, 5.9 cents per kWh and 5.4 cents per kWh, respectively. Estimates of Edison's future Avoided Cost of Energy vary substantially from year to year primarily based on the future cost of natural gas and may be impacted by regulatory proceedings and other commodity factors.

The Saranac Project is a 240-net MW natural gas-fired cogeneration facility located in Plattsburgh, New York owned by the Saranac Partnership, which is indirectly owned by subsidiaries of CE Generation, Osaka Gas Energy America Corporation and General Electric Capital Corporation. The Saranac Project has entered into a 15-year power purchase agreement with NYSE&G, 15-year steam purchase agreements with Georgia-Pacific Corporation and Pactiv Corporation and a 15-year natural gas supply contract with Coral Energy to supply 100% of the Saranac Project's fuel requirements. Each of the power purchase agreement, the steam purchase agreement and the natural gas supply contract contains rates that are fixed for the respective contract terms and expire in 2009.

The Power Resources project is a 212-net MW natural gas-fired cogeneration project owned by Power Resources Ltd. (or Power Resources), an indirect wholly owned subsidiary of CE Generation. On August 5, 2003, Power Resources entered into a Tolling Agreement with ONEOK Energy, Marketing and Trading Company, L.P. The agreement commenced October 1, 2003 and expired on December 31, 2005.

Power Resources currently operates as a merchant power plant and is subject to electricity and gas markets to economically dispatch its output. Power Resources entered into a one-year Energy Management Service Agreement with Mpower Trade and Marketing (or Mpower) effective January 1, 2006. Mpower is engaged to provide energy services required to manage the electrical generation, steam, and ancillary services capacity and related natural gas requirements of the plant. Mpower is due 10% of all net margins generated and Mpower's credit is used in all transactions with no credit assurance required from Power Resources.

The Yuma project is a 50-net MW natural gas-fired cogeneration project in Yuma, Arizona owned by Yuma Cogeneration Associates (or YCA), an indirect wholly owned subsidiary of CE Generation, providing its electricity to SDG&E under an existing 30-year power purchase contract which commenced in May 1994 (or the Yuma Contract). We have guaranteed all of the obligations of YCA under the Yuma Contract or any other agreement with SDG&E relating to or arising out of the Yuma Contract. YCA also has executed steam sales contracts with Queen Carpet, Inc. to act as its thermal host.

HomeServices

HomeServices 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 and mortgage banking, primarily through joint ventures, title and closing services and other 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 in 19 states under the following brand names: Carol Jones REALTORS, CBSHOME Real Estate, Champion Realty, Edina Realty Home Services, Esslinger-Wooten-Maxwell REALTORS, First Realty/GMAC, Harry Norman Realtors, HOME Real Estate, Huff Realty, Iowa Realty, Jenny Pruitt and Associates REALTORS, Long Realty, Prudential California Realty, Prudential Carolinas Realty, RealtySouth, Rector-Hayden REALTORS, Reece & Nichols, Roberts Brothers, Inc., Semonin REALTORS and Woods Bros. Realty. HomeServices generally occupies the number one or number two market share position in each of its major markets based on aggregate closed transaction sides. HomeServices' major markets consist of the following metropolitan areas: Minneapolis and St. Paul, Minnesota; Los Angeles and San Diego, California; Kansas City, Kansas; Kansas City and Springfield, Missouri; Des Moines, Iowa; Atlanta, Georgia; Omaha and Lincoln, Nebraska; Birmingham, Auburn and Mobile, Alabama; Tucson, Arizona; Winston-Salem and Charlotte, North Carolina; Louisville and Lexington, Kentucky; Annapolis, Maryland; Cincinnati, Ohio; and Miami, Florida.

Employees

At June 30, 2006, we employed approximately 18,100 people, of which approximately 7,800 are covered by union contracts. The majority of our union employees are employed by PacifiCorp and MidAmerican Energy 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.

Approximately 2,200 employees of PacifiCorp and its subsidiaries are covered by collective bargaining agreements that have expiration dates ranging from April 2007 to September 2009. Approximately 1,800 employees of PacifiCorp represented by International Brotherhood of Electrical Workers Local No. 57 are covered by three union contracts that expired earlier in 2006. PacifiCorp and the union are currently negotiating the renewal of these contracts. By separate agreement, the union is obligated to provide PacifiCorp a written notice of intent to strike at least 21 days in advance. No such notice has been received. MidAmerican Energy's union contract with International Brotherhood of Electrical Workers locals 109 and 499, which covers approximately 1,700 employee members, expires on April 30, 2009.

REGULATION

General Regulation

Regulated Utility Companies

PacifiCorp and MidAmerican Energy are subject to comprehensive regulation by the FERC, the UPSC, the OPUC, the WPSC, the WUTC, the IPUC, the CPUC, the IUB, the ICC, the SDPUC, and other federal, state and local regulatory agencies. These agencies regulate many aspects of our regulated utility companies' businesses, including customer rates, service territories, sales of securities, asset acquisitions and sales, accounting policies and practices, wholesale sales and purchases of electricity, and the operation of their electric generation and transmission facilities. PacifiCorp is a ''licensee'' and a ''public utility'' as those terms are used in the Federal Power Act. Most of PacifiCorp's hydroelectric plants are licensed by the FERC as major projects under the Federal Power Act. MidAmerican Energy is also a ''public utility'' within the meaning of the Federal Power Act and is a ''natural gas company'' within the meaning of the Natural Gas Act.

Federal Matters

General

On August 8, 2005, the Energy Policy Act was signed into law. That law potentially impacts many segments of the energy industry. A tax provision contained in the new law extended the federal production tax credit for new renewable electricity generation projects through December 31, 2007. In part as a result of that portion of the law, PacifiCorp and MidAmerican Energy began development efforts to add additional wind-powered generation. The law also results in expanding FERC regulatory authority in areas such as electric system reliability, electric transmission expansion and pricing, regulation of utility holding companies, and enforcement authority to issue substantial civil penalties. While the FERC has now issued rules and decisions on multiple aspects of the Energy Policy Act, the full impact of those decisions remains uncertain.

The Energy Policy Act repealed PUHCA 1935 and enacted the Public Utility Holding Company Act of 2005 (or PUHCA 2005), effective February 8, 2006. PUHCA 1935 extensively regulated and restricted the activities of registered public utility holding companies and their subsidiaries. PUHCA 2005 and the rules issued by the FERC to implement PUHCA 2005 require, among other things, public utility holding companies to permit access by the FERC to the books and records of the holding company and its affiliates transacting business with the public utility, unless such requirement is exempted or waived, and to comply with the FERC's record retention requirements. The repeal of PUHCA 1935 enabled Berkshire Hathaway to convert all of its shares of our no par, zero-coupon convertible preferred stock into an equal number of shares of our common stock thereby becoming our majority owner.

Market Power

The FERC regulates PacifiCorp's and MidAmerican Energy's rates charged to wholesale customers for energy and transmission services. Most of PacifiCorp's and MidAmerican Energy's electric wholesale sales and purchases take place under market-based pricing allowed by the FERC and are therefore subject to market volatility. The FERC conducts a triennial review of PacifiCorp's and MidAmerican Energy's market-based pricing authority during which they must demonstrate that they do not posses generation market power in order to charge market-based rates for sales of wholesale energy and capacity in their respective control areas. Margins earned on wholesale sales have historically been included as a component of retail cost of service upon which retail rates are based.

Pursuant to the FERC's orders granting PacifiCorp authority to sell capacity and energy at market-based rates, PacifiCorp and certain of its former affiliates had been required to submit a joint market power analysis every three years. In February 2005, PacifiCorp submitted a joint triennial

market power analysis, which indicated that PacifiCorp failed to pass one of the generation market power screens. In May 2005, the FERC issued an order instituting a proceeding pursuant to Section 206 of the Federal Power Act to determine whether PacifiCorp may continue to charge market-based rates for sales of wholesale energy and capacity. In June and July 2005, PacifiCorp and its formerly affiliated co-applicants submitted additional information and analysis to the FERC to rebut the presumption that PacifiCorp had generation market power. In January 2006, the FERC requested PacifiCorp to amend its previous filings with additional analysis, which was filed in March 2006. In June 2006, the FERC issued an order finding that PacifiCorp does not have market power and terminating the proceeding.

On July 13, 2004, the FERC issued an order requiring MidAmerican Energy to conduct a study to determine whether MidAmerican Energy or its affiliates possess generation market power. MidAmerican Energy is being required to show the absence of generation market power in order to be allowed to continue to sell wholesale electric power at market-based rates. The FERC order is intended to have MidAmerican Energy conform to what has become the FERC's general practice for utilities given authorization to make wholesale market-based sales. Under this general practice, utilities authorized to make market-based electric sales must submit a new market power study to the FERC every three years. MidAmerican Energy filed the required study on October 29, 2004. On June 1, 2005, the FERC issued an order setting for investigation the reasonableness of

MidAmerican Energy's market-based rates within its control area. The order also terminated the previously established November 1, 2004, refund date and instead required that market-based sales made by MidAmerican Energy within its control area beginning August 7, 2005, be subject to refund until the matter is resolved. The FERC also required MidAmerican Energy to file additional information by July 1, 2005, and August 1, 2005. In its August 1, 2005 filing, MidAmerican Energy filed a proposed cost-based sales tariff (or CBST) applicable to sales made within its control area to replace its market-based sales tariff. On March 17, 2006, the FERC issued an order (the ''March 17 Order'') accepting MidAmerican Energy's commitment not to make sales using market-based rates in its control area but rejected the proposed applicable tariff language. The FERC directed MidAmerican Energy to file revised tariff language by April 17, 2006. MidAmerican Energy made such filing together with a request for clarification, or in the alternative, rehearing (or the Request for Clarification) of the March 17 Order. MidAmerican Energy estimates that its maximum potential refund obligation is $17 million and its minimum potential refund obligation is $50,000 for the period August 7, 2005 through June 30, 2006. The actual refund will depend upon the FERC's ruling on the Request for Clarification and the applicability of the CBST to certain sales made within the control area for delivery outside the control area. MidAmerican Energy does not believe at this time that the ultimate outcome of this issue will have a material impact on its results of operations, financial position or cash flows.

Transmission

On July 22, 2005, MidAmerican Energy made a filing with the FERC requesting its approval to establish a transmission service coordinator (or TSC). The TSC would be a third-party administrator of various MidAmerican Energy OATT functions for transmission service. On December 16, 2005, the FERC issued an order conditionally accepting MidAmerican Energy's request to establish a TSC. The order requires MidAmerican Energy to make modifications to the draft TSC agreement filed with the FERC as part of the request and to file a final executed TSC agreement with the FERC for its review prior to the agreement becoming effective. MidAmerican Energy has entered into a contract with a third-party vendor to administer MidAmerican Energy's OATT. MidAmerican Energy does not believe that the incremental costs will have a material impact on its results of operations, financial position or cash flows. On June 15, 2006, the FERC issued an order conditionally approving MidAmerican Energy's selection of a third-party vendor. MidAmerican Energy anticipates the TSC commencing operations on August 30, 2006. Under the contract, the vendor would provide its tariff administration and planning services for a three-year term.

The FERC's Division of Operational Investigations of the Office of Market Oversight and Investigations (or OMOI) conducted several audits of electric utilities in 2003 and 2004 to determine if

Table of Contents

the utilities were complying with the FERC requirements under (1) standards of conduct and open access same-time information system and (2) codes of conduct regulations. On June 3, 2004, the OMOI informed MidAmerican Energy that it was commencing a similar audit of MidAmerican Energy, including its transmission practices. Following completion of the audit, on September 29, 2005, MidAmerican Energy agreed to take certain corrective actions of FERC-approved audit findings, which included $9.2 million in previously unscheduled transmission system upgrades. That capital expenditure will be excluded from MidAmerican Energy's rate base for six years during which time MidAmerican Energy will not earn a return on the transmission upgrades. In addition, MidAmerican Energy agreed to accelerate $14.7 million of scheduled transmission system upgrades. MidAmerican Energy has also implemented a compliance plan to address certain aspects of the audit findings relating to transmission practices and the administration of the OATT.

Hydroelectric

PacifiCorp's hydroelectric portfolio consists of 51 plants with an aggregate facility net owned capacity of 1,159.4 MW. The FERC regulates 93.9% of the installed capacity of this portfolio through 18 individual licenses. Several of PacifiCorp's hydroelectric plants are in some stage of relicensing with the FERC. Hydroelectric relicensing and the related environmental compliance requirements are subject to uncertainties. PacifiCorp expects that future costs relating to these matters may be significant and will consist primarily of additional relicensing costs, operations and maintenance expense, and capital expenditures. Electricity generation reductions may result from the additional environmental requirements. PacifiCorp has incurred $73.5 million in costs as of June 30, 2006 for ongoing hydroelectric relicensing. PacifiCorp expects that these and future costs will be included in rates and, if so included, will not have a material adverse impact on PacifiCorp's consolidated financial position or results of operations.

In February 2004, PacifiCorp filed with the FERC a final application for a new license to operate the 161.4-MW Klamath hydroelectric project. The FERC is scheduled to complete its required environmental analysis by January 2007. The U.S. Departments of Interior and Commerce filed proposed licensing terms and conditions with the FERC in March 2006; PacifiCorp filed alternatives to the federal agencies' proposal and challenges to its factual assumptions in April 2006. PacifiCorp continues to participate in the mediated settlement discussions with state and federal agencies, Native American tribes and other stakeholders in an effort to reach a comprehensive agreement on project relicensing. As of June 30, 2006, PacifiCorp has incurred costs of $38.1 million in the relicensing of the Klamath project. While the costs of implementing new license provisions cannot be determined until such time as a new license is issued, such costs could be significant.

Nuclear

MidAmerican Energy is subject to the jurisdiction of the NRC with respect to its license and 25% ownership interest in Quad Cities Station Units 1 and 2. Exelon Generation is the operator of Quad Cities Station and is under contract with MidAmerican Energy to secure and keep in effect all necessary NRC licenses and authorizations.

The NRC regulations control the granting of permits and licenses for the construction and operation of nuclear generating stations and subject such stations to continuing review and regulation. On October 29, 2004, the NRC granted renewed licenses for both Quad Cities Station Unit 1 and Unit 2 that provide for operation until December 14, 2032, which is in effect a 20-year extension of the licenses. 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

---

Table of Contents

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.

State Matters

General

PacifiCorp is subject to utility regulatory agencies in Utah, Oregon, Wyoming, Washington, Idaho and California, and MidAmerican Energy is subject to utility regulatory agencies in Iowa, Illinois and South Dakota, that collectively significantly influence the operating environment and the rates we can charge, incluidng the recoverability of costs from utility customers. Except for Illinois, that regulatory environment has to date, in general, given PacifiCorp and MidAmerican Energy an exclusive right to serve electricity customers within its service territory and, in turn, the obligation to provide electric service to those customers. In Illinois, all customers are free to choose their electricity provider and MidAmerican Energy has an obligation to serve customers at regulated rates that leave MidAmerican Energy’s system, but later choose to return. To date, there has been no significant loss of customers from MidAmerican Energy’s existing regulated Illinois rates.

We and PacifiCorp have made commitments to the state commissions that limit the dividends PacifiCorp can pay to us or our affiliates. As of June 30, 2006, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to us or our affiliates without prior state regulatory approval to the extent that it would reduce PacifiCorp’s common stock equity below 48.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. After December 31, 2008, this minimum level of common equity declines annually to 44.0% after December 31, 2011.

Utah

In March 2006, PacifiCorp filed a general rate case with the UPSC related to increased investments in Utah due to growing demand for electricity. In April 2006, PacifiCorp filed a revised case reflecting the effects of PacifiCorp’s sale to us, which reduced the original increase requested from $197.2 million to $194.1 million. In July 2006, a stipulation was reached with several parties and was filed with the UPSC. The stipulation calls for an annual increase of $115.0 million, or 9.95%, with $85.0 million of the increase effective December 11, 2006 and the remaining $30.0 million effective June 1, 2007. Under the terms of the stipulation, PacifiCorp has agreed not to file another rate case until after December 11, 2007. Hearings before the UPSC are set for August 2006.

Oregon

In February 2006, PacifiCorp filed a general rate case request with the OPUC for a revenue increase of $112.0 million, which represents a 13.2% overall increase. The request is related to investments in generation, transmission and distribution infrastructure and increases in fuel and general operating expenses, including power plant maintenance. In August 2006, a settlement agreement with all parties was filed with the OPUC. PacifiCorp will receive an increase of $43.0 million effective January 1, 2007, which reflects $33.0 million for non-power cost items and up to $10.0 million for power costs. PacifiCorp’s power costs will be updated via the existing annual transition adjustment mechanism with new rates effective January 1, 2008. PacifiCorp has agreed not to file a new rate case prior to September 1, 2007.

Table of Contents

In September 2005, Oregon’s governor signed into law Senate Bill 408. This legislation is intended to address differences between income taxes collected by Oregon public utilities currently in retail rates and actual taxes paid by the utilities or consolidated groups in which utilities are included for income tax reporting purposes. This legislation authorizes an automatic adjustment to rates based on the taxes paid to governmental entities on or after January 1, 2006. In July 2006, the OPUC issued an interim order establishing a method to determine federal, state and local taxes that are ‘‘properly attributed’’ to the regulated utility of a consolidated group using the lesser of defined stand alone taxes paid or taxes paid calculated using an apportionment formula based on a ratio of sales, payroll and property located in Oregon compared to the defined group for federal and state tax purposes applied to the taxes paid by the defined group. Therefore, the ratio of these factors and the federal taxes paid by Berkshire Hathaway and the state taxes paid by the defined group may impact the amount ‘‘properly attributed’’ to PacifiCorp. PacifiCorp filed comments in July 2006 seeking modifications on the interim order. A final order from the OPUC establishing the permanent rule is expected in September 2006. PacifiCorp will evaluate its legal and legislative options after the permanent rule is established.

In September 2005, the OPUC issued an order granting a general rate increase of $25.9 million or an average increase of 3.2%, effective October 2005. PacifiCorp filed its general rate case in November 2004, and following four partial stipulations with participating parties, PacifiCorp’s requested revenue requirement increase was $52.5 million. The OPUC’s order reduced PacifiCorp’s revenue requirement by $26.6 million based on the OPUC’s interpretation of Senate Bill 408. In October 2005, PacifiCorp filed with the OPUC a motion for reconsideration and rehearing of the rate order generally on the basis that the tax adjustment was not made in compliance with applicable law. With the motion, PacifiCorp also filed a deferred accounting application with the OPUC to track revenues related to the disallowed tax expenses. In July 2006, a final order was issued by the OPUC affirming its initial application of Senate Bill 408. The order also modified the tax adjustment, resulting in an additional annual increase in PacifiCorp's revenue of $6.1 million, effective July 2006 as well as granting deferred accounting from October 2005 to July 2006. PacifiCorp is reviewing its legal and regulatory options.

Wyoming

In March 2006, the WPSC approved an agreement that settled the general rate case filed by PacifiCorp in October 2005 and a separate request filed by PacifiCorp in December 2005 to recover increased costs of net wholesale purchased power used to serve Wyoming customers. The agreement provides for an annual rate increase of $15.0 million effective March 1, 2006, an additional annual rate increase of $10.0 million effective July 1, 2006, a power cost adjustment mechanism and an agreement by the parties to support a forecast test year in the next general rate case application.

Washington

In May 2005, PacifiCorp filed a general rate case request with the WUTC for a revenue increase of $39.2 million annually, which was later reduced to $30.0 million. In April 2006, the WUTC issued an order denying PacifiCorp's request to increase retail rates. The WUTC determined that application of PacifiCorp's cost allocation methodology failed to satisfy the statutory requirements that resources must benefit Washington ratepayers. In April 2006, PacifiCorp filed a petition for reconsideration of the order and requested an increase of not less than $11.0 million. PacifiCorp also filed a limited rate request seeking a rate increase of $7.0 million, which represents a 2.99% increase in rates. In June 2006, the WUTC suspended PacifiCorp's limited rate request and consolidated the request with the general rate case. In July 2006, the WUTC issued an order denying PacifiCorp's request for reconsideration and rejecting the 2.99% limited rate request filing. PacifiCorp is evaluating its legal and regulatory options for obtaining appropriate regulatory treatment in Washington.

Iowa

In conjunction with the March 1999 approval by the IUB of the MidAmerican Energy acquisition and March 2000 affirmation as part of our acquisition by a private investor group, MidAmerican

---

Table of Contents

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 of 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 equity level decreases to below 39%, even if the decrease is due to circumstances beyond the control of MidAmerican Energy. If MidAmerican Energy's common equity level were to drop below the required thresholds, MidAmerican Energy's ability to issue debt and declare dividends could be restricted.

Under a series of settlement agreements between MidAmerican Energy, the OCA and other interveners approved by the IUB, MidAmerican Energy has agreed not to seek a general increase in electric base rates to become effective prior to January 1, 2013 unless its Iowa jurisdictional electric return on equity for any year falls below 10%. 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 such 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, 2013. 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 revenues for MidAmerican Energy. The settlement agreements also each provide that portions of revenues associated with Iowa retail electric returns on equity within specified ranges will be recorded as a regulatory liability.

Under a settlement agreement approved by the IUB on December 21, 2001, which was effective through December 31, 2005, an amount equal to 50% of revenues associated with returns on equity between 12% and 14%, and 83.33% of revenues associated with returns on equity above 14%, in each year was recorded as a regulatory liability. A settlement agreement, which was filed in conjunction with MidAmerican Energy's application for ratemaking principles on its 2004/2005 wind-powered generation project and approved by the IUB on October 17, 2003, provides that during the period January 1, 2006 through December 31, 2010, an amount equal to 40% of revenues associated with returns on equity between 11.75% and 13%, 50% of revenues associated with returns on equity between 13% and 14%, and 83.3% of revenues associated with returns on equity above 14%, in each year will be recorded as a regulatory liability. The settlement agreement also includes commitments by MidAmerican Energy and the OCA not to seek or support a general increase or decrease, respectively, in electric base rate to become effective prior to January 1, 2011.

On January 31, 2005, the IUB approved a settlement agreement filed in conjunction with MidAmerican Energy's 2005 expansion of its wind-powered generation project On April 18, 2006, the IUB approved a settlement agreement filed in conjunction with MidAmerican Energy's application for up to 545 MW (nameplate ratings) of wind-powered generation capacity in Iowa. The settlement agreements extend the current revenue sharing mechanism through 2011 and 2012, respectively, and extend MidAmerican Energy's and the OCA's commitments regarding general increases or decreases in electric base rates through December 31, 2011 and 2012, respectively.

The regulatory liabilities created by the settlement agreements are recorded as a regulatory charge in depreciation and amortization expense when the liability is accrued. Additionally, interest expense is accrued on the portion of the regulatory liability balance recorded in prior years. Regulatory liabilities created for the years through 2010 will be reduced as they are credited against plant in service associated with generating plant additions. As a result of such credits applied to generating plant balances, future depreciation will be reduced. The regulatory liability accrued for 2011 and 2012, if any, will be credited to customer bills in 2012 and 2013, respectively.

Under Iowa law, there are two options for temporary collection of higher rates following the filing of a request for a rate increase. Collection can begin, subject to refund, either within 10 days of

filing, without IUB review, or 90 days after filing, with approval by the IUB. If the 10-day option is selected, Iowa law provides that if the utility is required to make refunds, the refunds may be based on overpayments made by each customer class, group or rate zone of the difference between final rates and the rates that would have been collected if temporary rates had been based upon prior regulatory principles. If the 90-day option is selected, Iowa law provides that the IUB shall prescribe the manner of refunding the difference between final rates and the rates based on prior ratemaking principles and a rate of return on common equity previously approved by the IUB. In either case, if the IUB has not issued a final order within ten months after the filing date, the temporary rates become final and any difference between the requested rate increase and the temporary rates may then be collected subject to refund until receipt of a final order. Exceptions to the ten-month limitation provide for extensions due to a utility's lack of due diligence in the rate proceeding, judicial appeals and situations involving new generating units being placed in service. MidAmerican Energy's cost of gas is collected in its Iowa gas rates through the Iowa Uniform Purchased Gas Adjustment Clause, which is updated monthly to reflect changes in actual costs.

Illinois

Under Illinois law, new rates may become effective 45 days after filing with the ICC, or on such earlier date as the ICC may approve, subject to its authority to suspend the proposed new rates, subject to hearing, for a period not to exceed approximately eleven months after filing. Under Illinois electric tariffs, MidAmerican Energy's Fuel Cost Adjustment Clause reflects changes in the cost of all fuels used for retail electric generation, including certain fuel transportation costs, nuclear fuel disposition costs and the cost of energy purchased from other utilities. MidAmerican Energy's cost of gas is reflected in its Illinois gas rates through the Illinois Uniform Purchased Gas Adjustment Clause. Both of the adjustment clauses are updated on a monthly basis to reflect changes in actual costs.

In December 1997, Illinois enacted a law to restructure Illinois' electric utility industry. The law changed how and what electric services are regulated by the ICC and transitions portions of the traditional electric services to a competitive environment. In general for the transition period that extends through 2006, the law allows for certain limits on the ICC's regulatory authority over a utility's generation and also relaxes its regulatory authority over many corporate transactions, such as the transfer of generation assets to affiliates. Special authority and limitations of authority apply during the transition to a competitive marketplace. Also, the law permits utilities to eliminate their fuel adjustment clauses and incorporates provisions by which earnings in excess of allowed amounts are either partially refunded to customers or are used to accelerate a company's asset recovery. Electric rates in Illinois are frozen until January 1, 2007, subject to certain exceptions allowing for increases, at which time bundled rates are subject to cost-based rate-making.

South Dakota

South Dakota law authorizes the SDPUC to suspend new rates for up to six months during the pendency of rate proceedings; however, the rates are permitted to be implemented after six months subject to refund pending a final order in the proceeding.

Interstate Pipeline Companies

General

Kern River and Northern Natural Gas are subject to regulation by various federal and state agencies. As owners of interstate natural gas pipelines, Northern Natural Gas' and Kern River's rates, services and operations are subject to regulation by the FERC. The FERC administers, among other things, the Natural Gas Act and the Natural Gas Policy Act of 1978. Additionally, interstate pipeline companies are subject to regulation by the DOT pursuant to the Natural Gas Pipeline Safety Act of 1968 (or NGPSA), which establishes safety requirements in the design, construction, operations and maintenance of interstate natural gas transmission facilities, and the PSIA, which implemented additional safety and pipeline integrity regulations for high consequence areas.

The FERC has jurisdiction over, among other things, 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. The FERC also has jurisdiction over the rates and charges and terms and conditions of service for the transportation of natural gas in interstate commerce.

Additional proposals and proceedings that might affect the interstate natural gas pipeline industry are considered from time to time by Congress, the FERC, state regulatory bodies and the courts. We cannot predict when or if any new proposals might be implemented or, if so, how Kern River and Northern Natural Gas might be affected.

Our pipeline operations are subject to regulation by the DOT under the NGPSA relating to design, installation, testing, construction, operation and management of its pipeline systems. The NGPSA requires any entity that owns or operates pipeline facilities to comply with applicable safety standards, to establish and maintain inspection and maintenance plans and to comply with such plans. Our pipeline operations conduct internal audits of their major facilities at least every four years, with more frequent reviews of those it deems of higher risk. The DOT also routinely audits these pipeline facilities. Compliance issues that arise during these audits or during the normal course of business are addressed on a timely basis.

The aging pipeline infrastructure in the United States has led to heightened regulatory and legislative scrutiny of pipeline safety and integrity practices. The NGPSA was amended by the Pipeline Safety Act of 1992 to require the DOT's Office of Pipeline Safety to consider protection of the environment when developing minimum pipeline safety regulations. In addition, the amendments require that the DOT issue pipeline regulations concerning, among other issues, the circumstances under which emergency flow restriction devices should be required, training and qualification standards for personnel involved in maintenance and operation, and requirements for periodic integrity inspections, as well as periodic inspection of facilities in navigable waters that pose a hazard to navigation or public safety. In addition, the amendments narrowed the scope of the exemption for gas pipelines from the underground storage tank requirements under the Resource Conservation and Recovery Act. We believe our pipeline systems comply in all material respects with the NGPSA.

The PSIA requires major new programs in the areas of operator qualification, risk analysis and integrity management. The PSIA requires the periodic inspection or testing of pipelines in areas where the potential consequences of a gas pipeline accident may be significant or may do considerable harm to people and their property, which are referred to as High Consequence Areas. Pursuant to the PSIA, the DOT promulgated new regulations, effective February 14, 2004, that require interstate pipeline operators to (i) develop comprehensive integrity management programs, (ii) identify applicable threats to pipeline segments that could impact High Consequence Areas, (iii) assess these segments, and (iv) provide ongoing mitigation and monitoring. We believe our pipeline operations comply in all material respects with the PSIA.

Rates

Kern River's tariff rates are designed to give it an opportunity to recover all actually and prudently incurred operations and maintenance costs of its pipeline system, taxes, interest, depreciation and amortization and a regulated equity return. 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; however, rate design is the subject of Kern River's current rate case before the FERC and may be subject to change as a result of the rate case outcome. This levelized cost of service has been achieved by using a FERC-approved depreciation schedule in which depreciation increases as interest expense decreases. If the Kern River system is converted to a traditional rate design as a result of the 2004 general rate case, the depreciation of Kern River's transmission system would be calculated on a straight-line basis over the expected economic life of its facilities. Under the traditional methodology, transportation rates do not remain constant over the lives of the shipper contracts, but rather are adjusted in each rate case to reflect current operating costs, updated depreciation rates and the rate base investment then in effect.

Kern River was required to file its 2004 general rate case no later than May 1, 2004 pursuant to the terms of its 1998 FERC Docket No. RP99-274 rate case settlement. Kern River filed its rate case

on April 30, 2004, which supports an annual revenue increase of $40.1 million representing a 13% increase from its existing cost of service and a proposed overall cost of service of $347.4 million. The rate increase became effective on November 1, 2004, subject to refund. Since its previous rate case, Kern River increased the capacity of its system from 724,500 Dth per day to 1,755,575 Dth per day at a cost of $1.3 billion. The filing employed the levelized rate methodology.

Kern River's 2004 general rate case hearing concluded in August 2005. On March 2, 2006, Kern River received an initial decision on the case from the administrative law judge, which, among other things, proposed an authorized rate of return of 9.34%. Kern River is currently authorized to collect an authorized rate of return of 13.25%. Briefs on exceptions were filed on April 3, 2006, and briefs opposing exceptions were filed on April 24, 2006. The administrative law judge's initial decision is non-binding and after briefing, the FERC will issue its initial decision on the case. The initial FERC decision, which may result in rate refunds, typically becomes binding on all parties while rehearing requests on the FERC decision and/or court appeals are pending. The initial FERC decision is not expected until late 2006 or early 2007. The final resolution of the rate case is dependent on receiving a final, non-appealable decision on the case from the FERC, or approval of a settlement of the case by the FERC.

Northern Natural Gas continues to use a straight fixed variable rate design which provides that all fixed costs assignable to firm capacity customers, including a return on equity, are to be recovered through fixed monthly demand or capacity reservation charges which are not a function of throughput volumes.

On May 1, 2003, Northern Natural Gas filed a general rate case proceeding for increased rates with the FERC and filed an additional rate case proceeding on January 30, 2004 to reflect further cost increases. The FERC consolidated the 2003 and 2004 rate cases due to the similarity of issues in both cases and the updated costs. On March 25, 2005, as modified on April 22, 2005, Northern Natural Gas filed a stipulation and agreement with the FERC (or the Settlement) resolving the consolidated rate cases. On June 20, 2005, the FERC approved the Settlement without modification. The Settlement represents the agreement Northern Natural Gas reached with its customers to settle the base tariff rates and related tariff issues in the consolidated cases. The Settlement provided for, among other things, rates designed to generate revenues on an annual basis above the base rates which were in effect as of October 31, 2003, as follows: $48 million for the period November 1, 2003 through October 31, 2004, $53 million for the period November 1, 2004 through October 31, 2005, $58 million for the period November 1, 2005 through October 31, 2006, and $62 million beginning November 1, 2006. Northern Natural Gas provided refunds including interest of $71.5 million to its customers in the third quarter of 2005 consistent with the terms of the Settlement, generally reflecting the difference between the rate increases implemented on November 1, 2003 and November 1, 2004 and the revenue generated using the Settlement rates.

In April 2004, Northern Natural Gas also filed tariff sheets with the FERC in relation to its SLA (an imbalance recovery mechanism) with the new rates going into effect on June 1, 2004, subject to refund. On February 14, 2005, Northern Natural Gas received FERC approval of the SLA settlement. The SLA settlement provides for recovery of the final SLA balance as of December 31, 2004, over a forty-eight month period beginning November 1, 2003. Under the SLA settlement, Northern Natural Gas is responsible for the financial impacts of managing operational storage volumes.

Electricity Distribution Companies

Since 1990, the electricity generation, transmission, supply and distribution industries in Great Britain have been privatized, and competition has been introduced in generation and supply, and, to a much more limited extent, in some aspects of distribution such as new connections and metering. Electricity is produced by generators, transmitted through the national grid transmission system and distributed to customers by the fourteen Distribution License Holders (or DLH) in their respective distribution services areas.

Under the Utilities Act 2000, the public electricity supply license created pursuant to the Electricity Act 1989 was replaced by two separate licenses – the electricity distribution license and the

electricity supply license. When the relevant provision of the Utilities Act 2000 became effective on October 1, 2001, the public electricity supply licenses formerly held by Northern Electric plc (or NE) and Yorkshire Electricity Group plc (or YE) were split so that separate subsidiaries held licenses for electricity distribution and electricity supply. In order to comply with the Utilities Act 2000 and to facilitate this license splitting, NE and YE (and each of the other holders of the former public electricity supply licenses) each made a statutory transfer scheme that was approved by the Secretary of State for Trade and Industry. These schemes provided for the transfer of certain assets and liabilities to the licensed subsidiaries. This occurred on October 1, 2001, a date set by the Secretary of State for Trade and Industry. As a consequence of these schemes, the electricity distribution businesses of NE and YE were transferred to Northern Electric and Yorkshire Electricity, respectively. Northern Electric and Yorkshire Electricity are each a DLH. The residual elements of the electricity supply licenses were transferred to Innogy Holdings plc (or Innogy), the predecessor of Npower, in connection with the sale of NE’s electricity and gas supply business to Innogy and the purchase by NE of YE’s electricity distribution business from Innogy on September 21, 2001.

DLHs are required to offer terms for connection to its distribution system and for use of its distribution system to any person. In providing the use of its distribution system, a DLH must not discriminate between users, nor may its charges differ except where justified by differences in cost.

Under the Utilities Act 2000, the GEMA, which in discharging certain of its powers acts through its staff within Ofgem, is able to impose financial penalties on license holders who contravene (or have in the past contravened) any of their license duties or certain of their duties under the Electricity Act 1989, as amended, or who are failing (or have in the past failed) to achieve a satisfactory performance in relation to the individual standards of performance prescribed by GEMA. Any penalty imposed must be reasonable and may not exceed 10% of the licensee’s revenue.

Most of the revenue of the DLHs in Great Britain is controlled by a distribution price control formula which is set out in the license of each DLH. It has been the practice of Ofgem (and its predecessor body, the Office of Electricity Regulation), to review and reset the formula at five-year intervals, although the formula has been, and may be, further reviewed at other times at the discretion of the regulator. Any such resetting of the formula requires the consent of the DLH. If the DLH does not consent to the formula reset, it is reviewed by the British competition commission, whose recommendations can then be given effect by license modifications made by Ofgem.

The current formula requires that regulated distribution income per unit is increased or decreased each year by RPI-Xd where RPI means the Retail Prices Index, reflecting the average of the 12-month inflation rates recorded for each month in the previous July to December period. The Xd factor in the formula was established by Ofgem at the price control review effective in April 2005 (and through March 31, 2010, is expected to continue to be set) at 0%. The formula also takes account of a variety of other factors including the changes in system electrical losses, the number of customers connected and the voltage at which customers receive the units of electricity distributed. The distribution price control formula determines the maximum average price per unit of electricity distributed (in pence per kWh) which a DLH is entitled to charge. The distribution price control formula permits DLHs to receive additional revenue due to increased distribution of units and the increase in the number of end users. The price control does not seek to constrain the profits of a DLH from year to year. It is a control on revenue that operates independently of most of the DLH’s costs. During the term of the price control, cost savings or additional costs have a direct impact on income and cash flow.

The procedure and methodology adopted at a price control review are at the reasonable discretion of Ofgem. Generally, Ofgem’s judgment of the future allowed revenue of licensees has been based upon, among other things:

- the actual operating costs of each of the licensees;
- the operating costs which each of the licensees would incur if it were as efficient as, in Ofgem’s judgment, the more efficient licensees;
- the taxes that each licensee is expected to pay;

- the regulatory value to be ascribed to each of the licensees’ distribution network assets;
- the allowance for depreciation of the distribution network assets of each of the licensees;
- the rate of return to be allowed on investment in the distribution network assets by all licensees; and
- the financial ratios of each of the licensees and the license requirement for each

licensee to maintain an investment grade status.

As a result of the review concluded in 2004, the allowed revenue of Northern Electric's distribution business was reduced by 4%, in real terms, and the allowed revenue of Yorkshire Electricity's distribution business was reduced by 9%, in real terms, with effect from April 1, 2005. Ofgem indicated that during the period 2005 to 2010, the retention of the benefits of any out-performance from the operating cost assumptions made by Ofgem in setting the new price control might depend on the successful implementation of revised cost reporting guidelines prescribed by Ofgem and to be applied by all DLHs.

The triennial process of valuing the UK pension plan's assets and liabilities, which valued the plan assets and liabilities as of March 31, 2004, was completed in 2005. This valuation set a revised level of contributions for the next three years. The report of the actuaries conducting the valuation showed a funding deficiency of £190.3 million. Based on this valuation, CE Electric UK will contribute £23.1 million to the pension plan each year in respect of the existing funding deficiency. The amount in respect of the funding deficiency has been calculated based on eliminating the funding deficiency over 12 years commencing April 1, 2005. In setting the allowed revenue of Northern Electric and Yorkshire Electricity (and all other DLHs) with effect from April 1, 2005, Ofgem made a specific allowance for an amount in respect of each DLH's pension costs, which reflects recovery of a significant portion of the deficiency payments.

With effect from April 1, 2005, a number of incentive schemes operate to encourage DLHs to provide an appropriate quality of service. Payments in respect of each failure to meet a prescribed standard of service are set out in regulations. The aggregate of payments that may be due is uncapped, although payments are excused in certain force majeure circumstances. In storm conditions the obligations relating to the period within which supplies should be restored are relaxed and the overall, annual exposure under the restoration standard in storm conditions is limited to 2% of a DLH's allowed revenue. There also is a discretionary reward scheme of up to £1 million per annum, and other incentive schemes pursuant to which a DLH's allowed revenue may increase by up to 3.3% or decrease by up to 3.5% in any year.

Independent Power Projects

Foreign

The Philippine Congress has passed EPIRA, which is aimed at restructuring the Philippine power industry, privatizing the NPC and introducing a competitive electricity market, among other initiatives. The implementation of EPIRA may have an impact on the Company's future operations in the Philippines and the Philippine power industry as a whole, the effect of which is not yet determinable or estimable.

In connection with the signing of the Supplemental Agreement, CE Casecnan received written confirmation from the Private Sector Assets and Liabilities Management Corporation that the issues with respect to the Casecnan Project that had been raised by the interagency review of independent power producers in the Philippines or that may have existed with respect to the project under certain provisions of EPIRA, which authorized the ROP to seek to renegotiate certain contracts such as the Project Agreement, have been satisfactorily addressed by the Supplemental Agreement.

Domestic

The Energy Policy Act also substantially amended the Public Utility Regulatory Policies Act of 1978 (or PURPA). PURPA and the regulations issued thereunder affected our and certain of our

Table of Contents

subsidiaries' operations by providing to qualifying facilities (or QF) certain exemptions from federal and state laws and regulations, including organizational, rate and financial regulation. New Section 210(m) eliminates the requirement that public utilities purchase the capacity and energy of QFs if the FERC determines that the requisite competitive market criteria are satisfied. In January 2006, the FERC instituted a rulemaking process to implement this section of the Energy Policy Act. The Energy Policy Act removed the 50% limitation on electric utility and electric utility holding company ownership of QFs. The Energy Policy Act does not authorize the termination of any existing contract and we do not expect the amendments to PURPA to have an adverse effect on us.

Each of the domestic power facilities in the CalEnergy Generation-Domestic platform, excluding Cordova Energy and Power Resources, meets the requirements promulgated under PURPA to be a QF. Prior to passage of the Energy Policy Act, QF status under PURPA provided two primary benefits. First, regulations under PURPA exempted QFs from PUHCA 1935, the FERC rate regulation under Sections 205 and 206 of the Federal Power Act and the state laws concerning rates of electric utilities and financial and organization regulations of electric utilities. Second, the FERC's regulations promulgated under PURPA required that (1) electric utilities purchase electricity generated by QFs, the construction of which commenced on or after November 9, 1978, at a price based on the purchasing utility's Avoided Cost of Energy, (2) electric utilities sell back-up, interruptible, maintenance and supplemental power to QFs on a non-discriminatory basis, and (3) electric utilities interconnect with QFs in their service territories. Following the effective date of repeal of PUHCA 1935, the exemption from PUHCA 1935 is no longer relevant, but QFs remain exempt from the accounting and reporting requirements of PUHCA 2005. QF sales that occur pursuant to existing contracts will continue to be exempt from FERC rate regulation under Sections 205 and 206 of the Federal Power Act. However, with respect to new contracts, QFs are no longer exempt from FERC's regulation of rates under Sections 205 and 206 of the Federal Power Act, unless the relevant sales are made pursuant to a state regulatory authority's implementation of PURPA.

In addition, in January 2006, the FERC issued a notice of proposed rulemaking to implement a provision of the Energy Policy Act, which eliminates the electric utilities' mandatory purchase obligation under PURPA if the FERC determines that certain conditions regarding QF access to transmission facilities and competitive markets are satisfied. Although the proposed rule does not permit electric utilities to terminate existing agreements, such as those now in place with CalEnergy Generation-Domestic, if the final rule is adopted substantially as proposed, the effect on us when the existing agreements terminate could be adverse. QF owners are required to provide notice to the FERC of a ''material change'' in facts in an application for recertification or notice of self-recertification. Subsequent notices of self-recertification for the same QF need only refer to changes which have occurred with respect to the facility since the prior notice or the prior FERC certification.

In another rulemaking proceeding to implement part of the Energy Policy Act, the FERC stated that exempt wholesale generators (or EWG) like Cordova Energy and Power Resources are not considered to be an electric utility company for the limited purpose of the FERC's access to the books and records of holding company systems under PUHCA 2005. As such, a EWG is permitted to sell capacity and electricity in the wholesale markets, but not in the retail markets. If a EWG is subject to a ''material change'' in facts that might affect its continued eligibility for EWG status, within 60 days of such material change, the EWG must (1) file a written explanation of why the material change does not affect its EWG status, (2) file a new application for EWG status, or (3) notify the FERC that it no longer wishes to maintain EWG status.

Residential Real Estate Brokerage Company

HomeServices is subject to regulations promulgated by the U.S. Department of Housing and Urban Development (or HUD) as well as regulatory agencies in the states within which it operates that significantly influence its operating environment. The House Committee on Financial Services, the Senate Committee on Banking, Housing and Urban Affairs and HUD each had indicated that reforming the Real Estate Settlement and Procedures Act (or RESPA) regulation was a priority in 2005. On June 27, 2005, HUD announced their plan to hold six roundtables to discuss with the

industry what provisions a new RESPA reform rule should contain. Those roundtables were held across the country in July and August 2005. HUD stated that it would publish its RESPA proposal in late 2005 and the Final Rule in 2006. As of December 31, 2005, HUD did not publish a RESPA proposal and has not indicated when a Final Rule will be issued in 2006. It is believed that this delay has been caused, in part, by the damage caused by hurricanes Katrina and Wilma. It is unknown whether a proposed rule will be introduced or finalized in 2006. Accordingly, we are presently unable to quantify the likely impact of any proposed rule, if issued.

Environmental Regulation

Domestic

General

Our domestic businesses are subject to numerous environmental laws, including the federal Clean Air Act and various state air quality laws; the Endangered Species Act; the Comprehensive Environmental Response, Compensation and Liability Act, and similar state laws relating to environmental cleanups; the Resource Conservation and Recovery Act and similar state laws relating to the storage and handling of hazardous materials; and the Clean Water Act, and similar state laws relating to water quality. These laws have the potential for impacting our operations. For example, the Clean Air Act will likely continue to impact the operation of PacifiCorp's and MidAmerican Energy's generating facilities and will likely require PacifiCorp and MidAmerican Energy to reduce emissions from those facilities through the installation of additional or improved emission controls, purchase additional emission allowances, or implement some combination thereof.

Such laws and regulations generally require our domestic businesses to obtain and comply with a wide variety of licenses, permits and other approvals. We believe that our operating power facilities and natural gas pipeline operations are currently in material compliance with all applicable federal, state and local laws and regulations. However, no guarantee can be given that in the future our domestic businesses will be in material compliance with all applicable environmental statutes and regulations or that all necessary permits will be obtained or approved. In addition, the construction of new power facilities and natural gas pipeline operations is a costly and time-consuming process requiring a multitude of complex environmental permits and approvals prior to the start of construction that may create the risk of expensive delays or material impairment of project value if projects cannot function as planned due to changing regulatory requirements or local opposition. We cannot provide assurance that existing regulations will not be revised or that new regulations will not be adopted or become applicable to it which could have an adverse impact on our capital or operating costs or our operations.

Under various federal, state and local environmental laws and regulations, a current or previous owner or operator of any facility may be required to investigate and remediate past releases or threatened releases of hazardous or toxic substances or petroleum products located at the facility, and may be held liable to a governmental entity or to third parties for property damage, personal injury and investigation and remediation costs incurred by a party in connection with certain releases or threatened releases. In certain cases liability for damages to natural resources may also be assessed. These laws, including the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended by the Superfund Amendments and Reauthorization Act of 1986, impose liability without regard to whether the owner knew of or caused the release of the hazardous substances, and courts have interpreted liability under such laws to be strict and joint and several. The cost of investigation, remediation or removal of substances may be substantial. In connection with our ownership and operation of power facilities and pipeline systems, we may become liable for such costs. Given the use of hazardous substances and/or petroleum products within our power facilities and pipeline systems, often within areas that have a long history of industrial use, it is possible that we will discover currently unknown contamination or that future spills or other causes of contamination will occur. As a result, even at those sites where we are not presently aware of any contamination that currently requires remediation, it is possible that we may become liable for additional remediation costs.

Our policy is to accrue environmental clean-up costs of a non-capital nature when those costs are believed to be probable and can be reasonably estimated. The quantification of environmental exposures is based on assessments of many factors, including changing laws and regulations, advancements in environmental technologies, the quality of information available related to specific sites, the assessment stage of each site investigation, preliminary findings and the length of time involved in remediation or settlement. The liability recorded at June 30, 2006 and December 31, 2005 was $43.4 million and $7.5 million, respectively.

Clean Air Standards

We are subject to applicable provisions of the Clean Air Act and related air quality standards promulgated by the EPA. The Clean Air Act provides the framework for regulation of certain air emissions and permitting and monitoring associated with those emissions. We believe we are in material compliance with current air quality requirements.

The EPA has in recent years implemented more stringent national ambient air quality standards for ozone and new standards for fine particulate matter. These standards set the minimum level of air quality that must be met throughout the United States. Areas that achieve the standards, as determined by ambient air quality monitoring, are characterized as being in attainment of the standard. Areas that fail to meet the standard are designated as being nonattainment areas. Generally, once an area has been designated as a nonattainment area, sources of emissions that contribute to the failure to achieve the ambient air quality standards are required to make emissions reductions. The EPA has concluded that the counties in Washington, Idaho, Montana, Wyoming, Colorado, Utah and Arizona, where PacifiCorp's major emission sources are located, and the entire state of Iowa, where MidAmerican Energy's major emission sources are located, are in attainment of the ozone and the current fine particulate matter standards.

In December 2005, the EPA proposed a revision of the ambient air quality standards for fine particles that would maintain the current annual standard and set a new, more stringent 24-hour standard for concentration of fine particulate in the ambient air. The EPA is scheduled to issue final rules in September 2006.

In March 2005, the EPA released the final Clean Air Mercury Rule (or CAMR). The CAMR utilizes a market-based cap and trade mechanism to reduce mercury emissions from coal-burning power plants from the 1999 nationwide level of 48 tons to 15 tons at full implementation. The CAMR's two-phase reduction program requires initial reductions of mercury emission in 2010 and an overall reduction in mercury emissions from coal-burning power plants of 70% by 2018. Individual states are required to implement the CAMR or alternative requirements to achieve equivalent or greater mercury emission reductions through their state implementation plans.

In March 2005, the EPA released the final Clean Air Interstate Rule (or CAIR), calling for reductions of SO_2 and NO_x emissions in the eastern United States through, at each state's option, a market-based cap and trade system, emission reductions, or both. The state of Iowa has implemented rules that exercise the option of the market-based cap and trade system. While the state of Iowa has been determined to be in attainment of the ozone and fine particulate standards, Iowa has been found to significantly contribute to nonattainment of the fine particulate standard in Cook County, Illinois; Lake County, Indiana; Madison County, Illinois; St. Clair County, Illinois; and Marion County, Indiana. The EPA has also concluded that emissions from Iowa significantly contribute to ozone nonattainment in Kenosha and Sheboygan counties in Wisconsin and Macomb County, Michigan. Under the final CAIR, the first-phase reductions of SO_2 emissions are effective on January 1, 2010, with the second-phase reductions effective January 1, 2015. For NO_x, the first-phase emissions reductions are effective January 1, 2009, and the second-phase reductions are effective January 1, 2015. The CAIR calls for overall reductions of SO_2 and NO_x in Iowa of 68% and 67%, respectively, from 2003 levels by 2015.

The CAMR or the CAIR could, in whole or in part, be superseded or made more stringent by one of a number of multi-pollutant emission reduction proposals currently under consideration at the federal level, including pending legislative proposals that contemplate 70% to 90% reductions of SO_2,

Table of Contents

NO_X and mercury, as well as possible new federal regulation of carbon dioxide and other gases that may affect global climate change. In addition to any federal legislation that could be enacted by Congress to supersede the CAMR and the CAIR, the rules could be changed or overturned as a result of litigation. The sufficiency of the standards established by both the CAMR and the CAIR has been legally challenged in the United States District Court for the District of Columbia.

The EPA has initiated a regional haze program intended to improve visibility at specific federally protected areas. Some of PacifiCorp's and MidAmerican Energy's plants meet the threshold applicability criteria under the Clean Air Visibility Rules. PacifiCorp and other stakeholders are participating in the Western Regional Air Partnership to help develop the technical and policy tools needed to comply with this program, while MidAmerican Energy and other stakeholders are participating in the Central States Regional Air Partnership to help develop the technical and policy tools needed to comply with this program.

As of June 30, 2006, PacifiCorp's environmental contingencies principally consist of air quality matters. Pending or proposed air regulations will require PacifiCorp to reduce the emissions of SO_2, NO_x and other pollutants at its generating facilities below current levels. The acquisition of PacifiCorp by MEHC includes a regulatory commitment to spend approximately $812 million to reduce emissions at PacifiCorp's generating facilities to address existing and future air quality requirements. These costs and any additional expenditures necessitated by air quality regulations are expected to be recoverable through the ratemaking process.

MidAmerican Energy has implemented a planning process that forecasts the site-specific controls and actions that may be required to meet emissions reductions as promulgated by the EPA. In accordance with an Iowa law passed in 2001, MidAmerican Energy has on file with the IUB its current multi-year plan and budget for managing SO_2 and NO_X from its generating facilities in a cost-effective manner. The plan, which is required to be updated every two years, provides specific actions to be taken at each coal-fired generating facility and the related costs and timing for each action. Pursuant to an unrelated rate settlement agreement approved by the IUB on October 17, 2003, if prior to January 1, 2011, capital and operating expenditures to comply with air quality requirements cumulatively exceed $325 million, then MidAmerican Energy may seek to recover the additional expenditures from customers.

Under existing New Source Review (or 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 (1) beginning construction of a new major stationary source of an NSR-regulated pollutant or (2) 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 are subject to pre-construction review and permitting under the Prevention of Significant Deterioration (or PSD) provisions of the Clean Air Act. Under the PSD program, a project that emits threshold levels of regulated pollutants must undergo a Best Available Control Technology analysis and evaluate the most effective emissions controls. These controls must be installed in order to receive a permit. Violations of NSR regulations, which may be alleged by the EPA, states, and environmental groups, among others, potentially subject a utility to material expenses for fines and other sanctions and remedies including requiring installation of enhanced pollution controls and funding supplemental environmental projects.

The EPA has requested from several utilities information and supporting documentation regarding their capital projects for various generating plants. The requests were issued as part of an industry-wide investigation to assess compliance with the NSR and the New Source Performance Standards of the Clean Air Act. In 2001 and 2003, PacifiCorp received requests for information from the EPA relating to PacifiCorp's capital projects at seven of its generating plants; PacifiCorp submitted information responsive to the requests, and there are currently no outstanding data requests pending from the EPA. In December 2002 and April 2003, MidAmerican Energy received requests from the EPA to provide documentation related to its capital projects from January 1, 1980, to April 2003 for a number of its generating plants. MidAmerican Energy has submitted information to the EPA in

Table of Contents

responses to these requests, and there are currently no outstanding data requests pending from the EPA. PacifiCorp and MidAmerican Energy cannot predict the outcome of these requests at this time.

In 2002 and 2003, the EPA proposed various changes to its NSR rules that clarify what constitutes routine repair, maintenance and replacement for purposes of triggering NSR requirements. These changes have been subject to legal challenge and, until such time as the legal challenges are resolved and the rules are effective, PacifiCorp and MidAmerican Energy will continue to manage projects at its generating plants in accordance with the rules in effect prior to 2002. In October 2005, the EPA proposed a rule that would change or clarify how emission increases are to be calculated for purposes of determining the applicability of the NSR permitting program for existing power plants.

In February 2005, the Kyoto Protocol became effective, requiring 35 developed countries to reduce greenhouse gas emissions by approximately 5% between 2008 and 2012. While the United States did not ratify the protocol, the ratification and implementation of its requirements in other countries has resulted in increased attention to climate change in the United States. In 2005, the Senate adopted a ''sense of the Senate'' resolution that puts the Senate on record that Congress should enact a comprehensive and effective national program of mandatory, market-based limits and incentives on emissions of greenhouse gases that slow, stop, and reverse the growth of such emissions at a rate and in a manner that will not significantly harm the United States economy; and will encourage comparable action by other nations that are major trading partners and key contributors to global emissions. It is anticipated that the resolution may be further addressed by Congress in 2006. While debate continues at the national level over the direction of domestic climate policy, several states are developing state-specific or regional legislative initiatives to reduce greenhouse gas emissions. In December 2005, the states of Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York and Vermont signed a mandatory regional pact to reduce greenhouse gas emissions that would become effective in 2009 and ultimately would require a reduction in greenhouse gas emissions of 10 percent from 1990 levels. An executive order signed by California's governor in June 2005 would reduce greenhouse gas emissions in that state to 2000 levels by 2010, to 1990 levels by 2020 and 80 percent below 1990 levels by 2050. In addition, California is seeking to apply a greenhouse gas emission performance standard to all electricity generated within the state or delivered from outside the state that is no higher than the greenhouse gas emission levels of a state-of-the-art combined-cycle natural gas generation facility.

Litigation was filed in the federal district court for the southern district of New York seeking to require reductions of carbon dioxide emissions from generating facilities of five large electric utilities. The court dismissed the public nuisance suit, holding that such critical issues affecting the United States such as greenhouse gas emissions reductions are not the domain of the court and should be resolved by the Executive Branch and the U.S. Congress. This ruling has been appealed to the Second Circuit Court of Appeals. The outcome of climate change litigation and federal and state initiatives cannot be determined at this time; however, adoption of stringent limits on greenhouse gas emissions could significantly impact our fossil-fueled facilities and, therefore, our results of operations.

The EPA's regulation of certain pollutants under the Clean Air Act, and its failure to regulate other pollutants, is being challenged by various lawsuits brought by both individual state attorney generals and environmental groups. To the extent that these actions may be successful in imposing additional and/or more stringent regulation of emissions on fossil-fueled facilities in general and PacifiCorp's and MidAmerican Energy's facilities in particular, such actions could significantly impact our fossil-fueled facilities and, therefore, our results of operations.

Clean Water Standards

Section 316(b) of the Clean Water Act requires that cooling water intake structures reflect the best technology available for minimizing ‘‘adverse environmental impacts’’ to aquatic organisms. On February 16, 2004, EPA Administrator Michael Leavitt signed the final Phase II rule for existing electric generating facilities. The rule sets significant new national technology-based performance standards 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. MidAmerican

Energy has completed a review of its historical Section 316(b) studies, as well as filed Proposals for Information Collection describing MidAmerican Energy’s plans for conducting biological field studies adjacent to its cooling water intake structures over the next two years. Although the impact of the MidAmerican Energy intake structures on aquatic organisms is unknown at this time, the previous Section 316(b) studies suggest that the impingement impact at the facility intake structures is minimal and that little if any intake structure expenditures will be necessary to meet the Section 316(b) impingement standard. Because of the high flow rate of the Missouri and Mississippi Rivers as compared to the withdrawal rates of the intake structures, the entrainment criteria of the Section 316(b) rule is not applicable to the MidAmerican Energy facilities. PacifiCorp is conducting similar impingement and entrainment studies to determine the impact of its cooling water intake structures on aquatic organisms. Should the new impingement studies show that the intakes are impacting the fish species, the intake structures may need to be modified to meet best technology standards. This could include significant expenditures involved with limiting the amount of water withdrawn from the applicable rivers and restrictions on the intake flow velocity.

Mine Reclamation

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. These obligations mandate that mine property be restored consistent with specific standards and the approved reclamation plan. PacifiCorp's mining operations are subject to these reclamation and closure requirements. Significant expenditures are being incurred for both ongoing and final reclamation. PacifiCorp's estimated mine and plant reclamation costs for its coal mines was $137.5 million at June 30, 2006 and is the asset retirement obligation for these mines. PacifiCorp has established trusts for the investment of funds for mine and plant reclamation. The fair value of the assets held in trusts was $99.6 million at June 30, 2006.

Nuclear

The NRC regulates the decommissioning of nuclear power plants including the planning and funding for the eventual decommissioning of the plants. In accordance with these regulations, MidAmerican Energy submits a report to the NRC every two years providing reasonable assurance that funds will be available to pay the costs of decommissioning its share of Quad Cities Station.

Under the Nuclear Waste Policy Act of 1982 (or NWPA), the U.S. Department of Energy (or DOE) is responsible for the selection and development of repositories for, and the permanent disposal of, spent nuclear fuel and high-level radioactive wastes. Exelon Generation, as required by the NWPA, signed a contract with the DOE under which the DOE was to receive spent nuclear fuel and high-level radioactive waste for disposal beginning not later than January 1998. The DOE did not begin receiving spent nuclear fuel on the scheduled date and remains unable to receive such fuel and waste. The earliest the DOE currently is expected to be able to receive such fuel and waste is 2010. The costs to be incurred by the DOE for disposal activities are being financed by fees charged to owners and generators of the waste. In 2004, Exelon Generation reached a settlement with the DOE concerning the DOE’s failure to begin accepting spent nuclear fuel in 1998. As a result, Quad Cities Station will be billing the DOE, and the DOE will be obligated to reimburse the station for all station costs incurred due to the DOE’s delay. Exelon Generation has completed construction of an interim spent fuel storage installation (or ISFSI) at Quad Cities Station to store spent nuclear fuel in dry casks in order to free space in the storage pool. The first pad at the ISFSI is expected to facilitate storage of casks to support operations at Quad Cities Station until at least 2017. The first storage in dry cask commenced in November 2005. In the 2017 to 2022 timeframe, Exelon Generation plans to add a second pad to the ISFSI to accommodate storage of spent nuclear fuel through the end of operations at Quad Cities Station.

Expected nuclear decommissioning costs for Quad Cities Station have been developed based on a site-specific decommissioning study that includes decontamination, dismantling, site restoration, dry fuel storage cost and an assumed shutdown date. Quad Cities Station nuclear decommissioning costs

are included in base rates in MidAmerican Energy's Iowa tariffs. MidAmerican Energy's share of estimated decommissioning costs for Quad Cities Station was $167.7 million and $163.0 million as of June 30, 2006 and December 31, 2005, respectively, and is the asset retirement obligation for Quad Cities Station. MidAmerican Energy has established trusts for the investment of funds for decommissioning the Quad Cities Station. The fair value of the assets held in the trusts was $234.6 million and $228.1 million, respectively, as of June 30, 2006 and December 31, 2005. MidAmerican Energy's depreciation and amortization includes costs for Quad Cities Station decommissioning. The regulatory provision charged to expense is equal to the funding that is being collected in Iowa rates.

United Kingdom

CE Electric UK’s businesses are subject to extensive regulatory requirements with respect to the protection of the environment. The principal legislation behind these regulations in relation to CE Electric UK activities is the Water Resources Act of 1991 and the Environmental Protection Act of 1990. The most relevant regulatory requirement is the Hazardous Waste (England and Wales) Regulations, which came into force in July 2005.

These regulations widened the scope of hazardous waste and have reclassified many waste products as hazardous that were previously regarded as non-hazardous waste. The cost of compliance with these requirements has been immaterial and we expect the ongoing cost of compliance will not have a material impact on us.

Philippines

On June 23, 1999, the Philippine Congress enacted the Philippine Clean Air Act of 1999 (or the Philippine Clean Air Act). The related implementing rules and regulations were adopted in November 2000. The law as written would require the Leyte Projects to comply with a maximum discharge of 200 grams of hydrogen sulfide per gross MWh of output by June 2004. On November 13, 2002, the Secretary of the Philippine Department of Environment and Natural Resources issued a Memorandum Circular (or MC) designating geothermal areas as ‘‘special airsheds.’’ PNOC-EDC has advised the Leyte Projects that the MC exempts the Mahanagdong and Malitbog plants from the need to comply with the point-source emission standards of the Philippine Clean Air Act.

Table of Contents

PROPERTIES

Our energy properties consist of the physical assets necessary and appropriate to generate, transmit, store, distribute and supply energy and consist mainly of electric generation, transmission and distribution facilities and gas distribution plants, natural gas pipelines, compressor stations and meter stations, along with the related rights-of-way. It is the opinion of management that the principal depreciable properties owned by us are in good operating condition and are well maintained. Pursuant to separate financing agreements, substantially all or most of the properties of each of our subsidiaries (except CE Electric UK, all of MidAmerican Energy’s gas utility properties and Northern Natural Gas) are pledged or encumbered to support or otherwise provide the security for their own project or subsidiary debt. For additional information regarding our energy properties, refer to the ‘‘Business’’ section of this prospectus and Note 5 and Note 12 of our Notes to the Unaudited Interim Consolidated Financial Statements and Note 4 and Note 22 of our Notes to the Audited Consolidated Financial Statements in the ‘‘Financial Statements’’ section of this prospectus.

The right to construct and operate our electric transmission and distribution facilities and pipelines across certain property was obtained through negotiations and through the exercise of the power of eminent domain, where necessary. PacifiCorp, MidAmerican Energy, Kern River and Northern Natural Gas in the United States and CE Electric UK 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 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 pipelines fall into two basic categories: (1) parcels that are owned in fee, such as certain of the generation stations, electric substations, compressor stations, measurement 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 pipelines. We believe that PacifiCorp, MidAmerican Energy, Kern River, Northern Natural Gas and CE Electric UK each have satisfactory title to all of the real property making up their respective facilities in all material respects.

Table of Contents

LEGAL PROCEEDINGS

In addition to the proceedings described below, we are currently party to various items of litigation or arbitration in the normal course of business, none of which are reasonably expected by us to have a material adverse effect on our financial position, results of operations or cash flows. See the ‘‘Environmental Regulation’’ section of this prospectus for details relative to our environmental matters.

Regulated Utility Companies

In May 2004, PacifiCorp was served with a complaint filed in the United States District Court for the District of Oregon by the Klamath Tribes of Oregon, individual Klamath Tribal members and the Klamath Claims Committee. The complaint generally alleges that PacifiCorp and its predecessors affected the Klamath Tribes' federal treaty rights to fish for salmon in the headwaters of the Klamath River in southern Oregon by building dams that blocked the passage of salmon upstream to the headwaters beginning in 1911. In September 2004, the Klamath Tribes filed their first amended complaint adding claims of damage to their treaty rights to fish for sucker and steelhead in the headwaters of the Klamath River. The complaint seeks in excess of $1.0 billion in compensatory and punitive damages. In July 2005, the District Court dismissed the case and in September 2005 denied the Klamath Tribes' request to reconsider the dismissal. In October 2005, the Klamath Tribes appealed the District Court's decision to the Ninth Circuit Court of Appeals and briefing was completed in March 2006. Any final order will be subject to appeal. PacifiCorp believes the outcome of this proceeding will not have a material impact on its consolidated financial position, results of operations or liquidity.

In October 2005, PacifiCorp was added as a defendant to a lawsuit originally filed in February 2005 in state district court in Salt Lake City, Utah by USA Power, LLC and its affiliated companies, USA Power Partners, LLC and Spring Canyon, LLC (collectively, USA Power), against Utah attorney Jody L. Williams and the law firm Holme, Roberts & Owen, LLP, who represent PacifiCorp on various matters from time to time. USA Power is the developer of a planned generation project in Mona, Utah, called Spring Canyon, which PacifiCorp, as part of its resource procurement process, at one time considered as an alternative to the Currant Creek Power Plant. USA Power's complaint alleges that PacifiCorp misappropriated confidential proprietary information in violation of Utah's Uniform Trade Secrets Act and accuses PacifiCorp of breach of contract and related claims. USA Power seeks $250.0 million in damages, statutory doubling of damages for its trade secrets violation claim, punitive damages, costs and attorneys' fees. PacifiCorp believes it has a number of defenses and intends to vigorously oppose any claim of liability for the matters alleged by USA Power. Furthermore, PacifiCorp expects that the outcome of this proceeding will not have a material impact on its consolidated financial position, results of operations or liquidity.

On December 28, 2004, an apparent gas explosion and fire resulted in three fatalities, one serious injury and property damage at a commercial building in Ramsey, Minnesota. According to the Minnesota Office of Pipeline Safety, an improper installation of a pipeline connection may have been a cause of the explosion and fire. A predecessor company to MidAmerican Energy allegedly provided gas service in Ramsey, Minnesota at the time of the original installation in 1980. In 1993, a predecessor of CenterPoint Energy, Inc. (or CenterPoint) acquired all of the Minnesota gas properties owned by the MidAmerican Energy predecessor company.

As a result of the explosion and fire, MidAmerican Energy and CenterPoint have received settlement demands which total $15.5 million. MidAmerican Energy's exposure, if any, to these demands are covered under its liability insurance coverage to which a $2.0 million retention applies. In addition, counsel for CenterPoint stated that a replacement program has been initiated for the purpose of locating and replacing all mechanical couplings in the former North Central Public Service Company properties located in Minnesota. Counsel for CenterPoint has represented that the value of the replacement claim may be in the range of $35-$45 million.

Two lawsuits are currently on file related to this incident. On February 8, 2006, MidAmerican Energy was served with a Third Party Complaint filed in U.S. District Court, District of Minnesota, by

CenterPoint Resources Corp. d/b/a CenterPoint Energy. The Third Party Complaint seeks contribution and indemnity on a wrongful death claim filed by the estate of one of the decedents and all sums associated with CenterPoint's replacement program. CenterPoint Energy Resources Corp. has settled the wrongful death claim with the trustee for the estate of the decedent; however, the Third Party action by CenterPoint Energy Resources Corp. against MidAmerican Energy remains. MidAmerican Energy was served with a second Third Party Complaint filed in U.S. District Court, District of Minnesota, by CenterPoint seeking contribution and indemnity on a property damage and business interruption claim filed by Ramsey Premier Partners, LLC, and all sums associated with CenterPoint's replacement program. MidAmerican Energy filed a motion for summary judgment in both of these cases that was heard on July 11, 2006 and the decision is pending. We and MidAmerican Energy intend to vigorously defend our position in these claims and believe their ultimate outcome will not have a material impact on our results of operations, financial position or cash flows.

Interstate Pipeline Companies

In 1998, the United States Department of Justice informed the then current owners of Kern River and Northern Natural Gas that Jack Grynberg, an individual, had filed claims in the United States District Court for the District of Colorado under the False Claims Act against such entities and certain of their subsidiaries including Kern River and Northern Natural Gas. Mr. Grynberg has also filed claims against numerous other energy companies and alleges that the defendants violated the False Claims Act in connection with the measurement and purchase of hydrocarbons. The relief sought is an unspecified amount of royalties allegedly not paid to the federal government, treble damages, civil penalties, attorneys’ fees and costs. On April 9, 1999, the United States Department of Justice announced that it declined to intervene in any of the Grynberg qui tam cases, including the actions filed against Kern River and Northern Natural Gas in the United States District Court for the District of Colorado. On October 21, 1999, the Panel on Multi-District Litigation transferred the Grynberg qui tam cases, including the ones filed against Kern River and Northern Natural Gas, to the United States District Court for the District of Wyoming for pre-trial purposes. On October 9, 2002, the United States District Court for the District of Wyoming dismissed Grynberg’s royalty valuation claims. On November 19, 2002, the United States District Court for the District of Wyoming denied Grynberg’s motion for clarification and dismissed his royalty valuation claims. Grynberg appealed this dismissal to the United States Court of Appeals for the Tenth Circuit and on May 13, 2003, the Tenth Circuit Court dismissed his appeal. On May 17, 2005, Kern River and Northern Natural Gas each received a Special Master’s Report and Recommendations in which the Special Master recommended that the action against Kern River and Northern Natural Gas be dismissed for lack of subject matter jurisdiction. Grynberg and the coordinated defendants each filed motions relating to the Special Master’s Report and Recommendations on June 27, 2005. Oral arguments on the parties’ motions were held on December 9, 2005, and the parties are awaiting a ruling from the court regarding this report. In connection with the purchase of Kern River from The Williams Companies, Inc. (or Williams) in March 2002, Williams agreed to indemnify us against any liability for this claim; however, no assurance can be given as to the ability of Williams to perform on this indemnity should it become necessary. No such indemnification was obtained in connection with the purchase of Northern Natural Gas in August 2002. We believe that the Grynberg cases filed against Kern River and Northern Natural Gas are without merit and that Williams, on behalf of Kern River pursuant to its indemnification, and Northern Natural Gas, intend to defend these actions vigorously.

On June 8, 2001, a number of interstate pipeline companies, including Kern River and Northern Natural Gas, were named as defendants in a nationwide class action lawsuit which had been pending in the 26th Judicial District, District Court, Stevens County Kansas, Civil Department against other defendants, generally pipeline and gathering companies, since May 20, 1999. The plaintiffs allege that the defendants have engaged in mismeasurement techniques that distort the heating content of natural gas, resulting in an alleged underpayment of royalties to the class of producer plaintiffs. On May 12, 2003, the plaintiffs filed a motion for leave to file a fourth amended petition alleging a class of gas royalty owners in Kansas, Colorado and Wyoming. The court granted the motion for leave to amend on July 28, 2003. Kern River was not a named defendant in the amended complaint and has been dismissed from the action. Northern Natural Gas filed an answer to the fourth amended petition on August 22, 2003. On January 4, 2005, the plaintiffs filed their class certification motion and brief in support of that motion. Northern Natural Gas filed its joint brief and expert affidavits in opposition to class certification on February 22, 2005. The plaintiffs filed their reply brief in support of class certification on March 18, 2005. Northern Natural Gas believes that this claim is without merit.

Similar to the June 8, 2001 matter referenced above, the plaintiffs in that matter have filed a new companion action against a number of parties, including Northern Natural Gas but excluding Kern River, in a Kansas state district court for damages for mismeasurement of British thermal unit content, resulting in lower royalties. The action was filed on May 12, 2003. On January 4, 2005, the plaintiffs filed their class certification motion and brief in support of that motion. Northern Natural Gas filed its joint brief and expert affidavits in opposition to class certification on February 22, 2005. The plaintiffs filed their reply brief in support of class certification on March 18, 2005. Northern Natural Gas believes that this claim is without merit.

Table of Contents

Independent Power Projects

Pursuant to the share ownership adjustment mechanism in the CE Casecnan stockholder agreement, which is based upon pro forma financial projections of the Casecnan project prepared following commencement of commercial operations, in February 2002, our indirect wholly-owned subsidiary, CE Casecnan Ltd., advised the minority stockholder of CE Casecnan, LaPrairie Group Contractors (International) Ltd. (or LPG), that our indirect ownership interest in CE Casecnan had increased to 100% effective from commencement of commercial operations. On July 8, 2002, LPG filed a complaint in the Superior Court of the State of California, City and County of San Francisco against us and CE Casecnan Ltd. LPG's complaint, as amended, seeks compensatory and punitive damages arising out of CE Casecnan Ltd.'s and our alleged improper calculation of the proforma financial projections On January 21, 2004, CE Casecnan Ltd., LPG and CE Casecnan entered into a status quo agreement pursuant to which the parties agreed to set aside certain distributions related to the shares subject to the LPG dispute and CE Casecnan agreed not to take any further actions with respect to such distributions without at least 15 days prior notice to LPG. Accordingly, 15% of the CE Casecnan dividend distributions declared in 2004, 2005 and 2006, totaling $26.0 million, was set aside in a separate bank account in the name of CE Casecnan and is shown as restricted cash and short-term investments and other current liabilities.

On August 4, 2005, the court issued a decision, ruling in favor of LPG on five of the eight disputed issues in the first phase of the litigation. On September 12, 2005, LPG filed a motion seeking the release of the funds which have been set aside pursuant to the status quo agreement referred to above. We and CE Casecnan Ltd. filed an opposition to the motion on October 3, 2005, and at the hearing on October 26, 2005, the court denied LPG's motion. On January 3, 2006, the court entered a judgment in favor of LPG against CE Casecnan Ltd. According to the judgment LPG would retain its ownership of 15% of the shares of CE Casecnan and distributions of the amounts deposited into escrow plus interest at 9% per annum. On February 28, 2006, CE Casecnan Ltd. filed an appeal of this judgment and the August 4, 2005 decision. Initial briefs and reply briefs were filed May 24, 2006 and August 1, 2006, respectively. The appeal is expected to be resolved sometime in 2007. The impact, if any, of this litigation on us cannot be determined at this time.

In February 2003, San Lorenzo Ruiz Builders and Developers Group, Inc. (or San Lorenzo), an original shareholder substantially all of whose shares in CE Casecnan were purchased by us in 1998, threatened to initiate legal action against us in the Philippines in connection with certain aspects of its option to repurchase such shares. On July 1, 2005, we and CE Casecnan Ltd. commenced an action against San Lorenzo in the District Court of Douglas County, Nebraska, seeking a declaratory judgment as to our and CE Casecnan Ltd.'s rights vis-à-vis San Lorenzo in respect of such shares. San Lorenzo filed a motion to dismiss on September 19, 2005. Subsequently, San Lorenzo purported to exercise its option to repurchase such shares. On January 30, 2006, San Lorenzo filed a counterclaim against us and CE Casecnan Ltd. seeking declaratory relief that it has effectively exercised its option to purchase 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. On March 9, 2006, the court granted San Lorenzo's motion to dismiss, but has since permitted us and CE Casecnan Ltd. to file an amended complaint incorporating the purported exercise of the option. The impact, if any, of San Lorenzo's purported exercise of its option and the Nebraska litigation on us cannot be determined at this time. We intend to vigorously defend the counterclaims.

Table of Contents

MANAGEMENT

Our management structure is organized functionally and our current executive officers and directors and their positions are as follows:

Name	Position
David Sokol	Chairman of the Board of Directors and Chief Executive Officer
Gregory E. Abel	President, Chief Operating Officer and Director
Patrick J. Goodman	Senior Vice President and Chief Financial Officer

Douglas L. Anderson	Senior Vice President, General Counsel and Corporate Secretary
Maureen E. Sammon	Senior Vice President, Human Resources, Information Technology and Insurance
Keith D. Hartje	Senior Vice President, Communications, General Services and Safety Audit and Compliance
Warren E. Buffett	Director
Walter Scott Jr.	Director
Marc D. Hamburg	Director

Officers are elected annually by the Board of Directors. There are no family relationships among the executive officers, nor any arrangements or understanding between any officer and any other person pursuant to which the officer was appointed.

Set forth below is certain information, as of June 30, 2006, with respect to each of the foregoing officers and directors:

DAVID L. SOKOL, 49, Chairman of the Board of Directors and Chief Executive Officer. Mr. Sokol has been the Chief Executive Officer since April 19, 1993 and served as our President from April 19, 1993 until January 21, 1995. Mr. Sokol has been Chairman of the Board of Directors since May 1994 and a director since March 1991. Formerly, among other positions held in the independent power industry, Mr. Sokol served as President and Chief Executive Officer of Kiewit Energy Company, which at that time was a wholly owned subsidiary of Peter Kiewit & Sons', Inc., and Ogden Projects, Inc.

GREGORY E. ABEL, 44, President, Chief Operating Officer and Director. Mr. Abel joined us in 1992 and initially served as Vice President and Controller. Mr. Abel is a Chartered Accountant and from 1984 to 1992 was employed by PricewaterhouseCoopers. As a Manager in the San Francisco office of PricewaterhouseCoopers, he was responsible for clients in the energy industry.

PATRICK J. GOODMAN, 39, Senior Vice President and Chief Financial Officer. Mr. Goodman joined us in 1995 and has served in various financial positions including Chief Accounting Officer. Prior to joining us, Mr. Goodman was a financial manager for National Indemnity Company and a senior associate at PricewaterhouseCoopers.

DOUGLAS L. ANDERSON, 48, Senior Vice President, General Counsel and Corporate Secretary. Mr. Anderson joined us in February 1993 and has served in various legal positions including General Counsel of our independent power affiliates. Prior to that, Mr. Anderson was a corporate attorney in private practice.

MAUREEN E. SAMMON, 42, Senior Vice President, Human Resources, Information Technology and Insurance. Ms. Sammon has been with MidAmerican Energy and its predecessor companies since 1986. In that time, she has held several positions, including Manager of Benefits and Vice President, Human Resources and Insurance.

KEITH D. HARTJE, 56, Senior Vice President, Communications, General Services and Safety Audit and Compliance. Mr. Hartje has been with MidAmerican Energy and its predecessor companies since 1973. In that time, he has held a number of positions, including General Counsel and Corporate Secretary, District Vice President for southwest Iowa operations, and Vice President, Corporate Communications.

Table of Contents

WARREN E. BUFFETT, 75, Director. Mr. Buffett has been a director of ours since March 2000. He is Chairman of the Board and Chief Executive Office of Berkshire Hathaway. Mr. Buffett is a Director of The Washington Post Company.

WALTER SCOTT, JR., 75, Director. Mr. Scott has been a director of ours since June 1991. Mr. Scott was our Chairman and Chief Executive Officer from January 8, 1992 until April 19, 1993. For more than five years, he has been Chairman of the Board of Directors of Level 3 Communications, Inc., a successor to certain businesses of Peter Kiewit & Sons', Inc. Mr. Scott is a director of Peter Kiewit & Sons', Inc., Berkshire Hathaway, Burlington Resources, Inc., Valmont Industries, Inc. and Commonwealth Telephone Enterprises, Inc.

MARC D. HAMBURG, 56, Director. Mr. Hamburg has been a director of ours since March 2000. He has served as Vice President – Chief Financial Officer of Berkshire Hathaway since October 1, 1992 and Treasurer since June 1, 1987, his date of employment with Berkshire Hathaway.

Audit Committee Members and Financial Experts

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. Mr. Hamburg is not independent within the meaning of Item 7(d)(3)(iv) of Schedule 14A under the Exchange Act.

Code of Ethics

We have adopted a code of ethics that applies to our principal executive officer, our principal financial officer, our chief accounting officer and certain other covered officers. The code of ethics is filed as an exhibit to our annual report on Form 10-K for the year ended December 31, 2005.

Table of Contents

Executive Compensation

The following table sets forth the compensation of our Chief Executive Officer and our four other most highly compensated executive officers who were employed as of December 31, 2005, which we refer to as our Named Executive Officers. Information is provided regarding our Named Executive Officers for the last three fiscal years during which they were our executive officers, if applicable.

Name and Principal Position	Year Ended Dec. 31	Salary(1)	Bonus(1)	Other Annual Comp(2)	LTIP Payouts	All Other Comp(3)
David L. Sokol	2005	$850,000	$13,750,000	$103,929	$	$ 10,290
Chairman and Chief Executive Officer	2004	800,000	2,500,000	131,644	—	9,995
	2003	800,000	2,750,000	141,501	—	9,800
Gregory E. Abel	2005	740,000	13,450,000	—	—	10,290
President, Chief Operating Officer	2004	720,000	2,200,000	80,424	—	9,995
	2003	700,000	2,200,000	87,162	—	9,800
Patrick J. Goodman	2005	297,500	325,000	—	107,212	67,269
Senior Vice President and Chief	2004	290,000	295,000	—	257,694	88,391
Financial Officer	2003	275,000	285,000	—	—	108,631
Douglas L. Anderson	2005	275,000	265,000	—	87,769	60,456
Senior Vice President, General	2004	270,000	240,000	—	151,585	77,145
Counsel	2003	260,000	240,000	—	—	83,703
Maureen E. Sammon	2005	175,000	110,000	—	—	39,397
Senior Vice President, Human	2004	165,000	80,000	—	—	42,236
Resources, Information Technology and Insurance	2003	147,500	65,000	—	—	35,223

(1) Includes amounts voluntarily deferred by the executive, if applicable. Pursuant to our Executive Incremental Profit Sharing Plan, Messrs. Sokol and Abel each received a profit-sharing award of $11.25 million based upon achieving the specified adjusted diluted earnings per share target for the year ended December 31, 2005. Messrs. Sokol and Abel are each eligible to receive additional profit-sharing awards of $7.5 million or $26.25 million based upon achieving specified adjusted diluted earnings per share targets for any calendar year 2006 and 2007. In 2005, Messrs. Goodman and Anderson and Ms. Sammon each received a performance award related to the pending acquisition of PacifiCorp.

(2) Consists of perquisites and other benefits if the aggregate amount of such benefits exceeds the lesser of either $50,000 or 10% of the total of salary and bonus reported for the Named Executive Officer. The amounts shown include the personal use of aircraft for 2005 for Mr. Sokol of $76,811.

(3) Consists of the 2005 earnings on our Long-Term Incentive Partnership Plan (or LTIP) awards not paid out in 2005 and 401(k) plan contributions. For 2005, LTIP earnings on awards not paid out in 2005 were $56,979 for Mr. Goodman, $50,166 for Mr. Anderson and $29,457 for Ms. Sammon. Messrs. Sokol and Abel are not participants in the LTIP. Additionally, the amounts shown include company 401(k) contributions for 2005 for Messrs. Sokol, Abel, Goodman and Anderson of $10,290 and for Ms. Sammon of $9,940.

Option Grants in Last Fiscal Year

We did not grant any options during 2005.

Table of Contents

Aggregated Option Exercises in Last Fiscal Year and Fiscal Year End Option Values

The following table sets forth the option exercises and the number of securities underlying exercisable and unexercisable options held by each of our Named Executive Officers at December 31, 2005.

Name	Shares Acquired On Exercise(#)	Value Realized ($)	Underlying Unexercised Options Held(#)		Value of Unexercised In-the-money Options ($)(1)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
David Sokol	200,000	$16,798,740	$1,199,277	—	$134,652,051	N/A
Gregory E. Abel	—	—	649,052	—	76,518,336	N/A
Patrick J. Goodman	—	—	—	—	—	—
Douglas L. Anderson	—	—	—	—	—	—
Maureen E. Sammon	—	—	—	—	—	—

(1) On March 14, 2000, we were acquired by a private investor group and on February 9, 2006, became a majority-owned subsidiary of Berkshire Hathaway. As a privately held company, we have no publicly traded equity securities. The value shown is based on an assumed fair market value of the common stock of $145 per share as of December 31, 2005, as agreed to by our stockholders.

Long-Term Incentive Partnership Plan – Awards in Last Fiscal Year

Name	Number of Shares, Units or OtherRights(#)	Performance or Other Period Until Maturation or Payout	Threshold ($) (1)	Target ($)(1)	Maximum ($)(1)
Patrick J. Goodman	N/A	December 31, 2009	446,250	N/A	N/A
Douglas L. Anderson	N/A	December 31, 2009	404,406	N/A	N/A

Maureen E. Sammon	N/A	December 31, 2009	262,500	N/A	N/A

(1) The awards shown in the foregoing table are made pursuant to the LTIP. The amounts shown are dollar amounts credited to an investment account for the benefit of the named executive officers and such amounts vest equally over five years (starting with year 2005) with any unvested balances forfeited upon termination of employment. Vested balances (including any investment performance profits or losses thereon) are paid to the participant at the time of termination. Once an award is fully vested, the participant may elect to defer or receive payment of part or the entire award. Awards are credited or reduced with annual interest or loss based on a composite of funds or indices. Because the amounts to be paid out may increase or decrease depending on investment performance, the ultimate benefits are undeterminable and the payouts do not have a ''target'' or ''maximum'' amount.

Compensation of Directors

Directors are not paid any fees for serving as directors. All directors are reimbursed for their expenses incurred in attending Board meetings.

Retirement Plans

The MidAmerican Energy Company Supplemental Retirement Plan for Designated Officers (or the SERP), provides additional retirement benefits to designated participants, as determined by the Board of Directors. Messrs. Sokol, Abel and Goodman are participants in the SERP. The SERP provides annual retirement benefits up to sixty-five percent of a participant's Total Cash Compensation in effect immediately prior to retirement, subject to a $1 million maximum retirement benefit. ''Total Cash Compensation'' means the highest amount payable to a participant as monthly base salary during the five years immediately prior to retirement multiplied by 12 plus the average of the participant's last three years awards under an annual incentive bonus program and special,

Table of Contents

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. Participants must be credited with five years of service to be eligible to receive benefits under the SERP. Each of the Messrs. Sokol, Abel and Goodman has five years of credited service with us and will be eligible to receive benefits under the SERP. A participant who elects early retirement is entitled to reduced benefits under the SERP, however, in accordance with their respective employment agreements, Messrs. Sokol and Abel are eligible to receive the maximum retirement benefit at age 47. 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 the 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. The SERP benefit will be reduced by the amount of the participant's regular retirement benefit under the MidAmerican Energy Company Cash Balance Retirement Plan (or the MidAmerican Retirement Plan), which became effective January 1, 1997.

The MidAmerican Retirement Plan replaced retirement plans of predecessor companies that were structured as traditional, defined benefit plans. Under the MidAmerican Retirement Plan, each participant has an account, for record keeping purposes only, to which credits are allocated annually based upon a percentage of the participant's salary paid in the plan year. In addition, all balances in the accounts of participants 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. At retirement, or other termination of employment, an amount equal to the vested balance then credited to the account is payable to the participant in the form of a lump sum or a form of annuity for the entire benefit under the MidAmerican Retirement Plan. The estimated annual benefit payable upon normal retirement age (65) for Mr. Anderson is $89,109 and for Ms. Sammon is $141,535. These estimates assume an interest credit rate of 6.0 percent and conversion to a life annuity using plan mortality and 6.0 percent interest. Mr. Anderson and Ms. Sammon are not participants in the SERP.

The table below shows the estimated aggregate combined annual benefits payable under the SERP and the MidAmerican Retirement Plan. The amounts exclude Social Security and are based on a straight life annuity and retirement at ages 55, 60 and 65. Federal law limits the amount of benefits payable to an individual through the tax qualified defined benefit and contribution plans, and benefits exceeding such limitation are payable under the SERP.

Total Cash Compensation at Retirement ($)	Estimated Annual Benefit Age of Retirement		
	55	60	65
$ 400,000	$ 220,000	$ 240,000	$ 260,000
500,000	275,000	300,000	325,000
600,000	330,000	360,000	390,000
700,000	385,000	420,000	455,000
800,000	440,000	480,000	520,000
900,000	495,000	540,000	585,000
1,000,000	550,000	600,000	650,000
1,250,000	687,500	750,000	812,500
1,500,000	825,000	900,000	975,000
1,750,000	962,500	1,000,000	1,000,000
2,000,000 and greater	1,000,000	1,000,000	1,000,000

Employment Agreements

Pursuant to his employment agreement, Mr. Sokol serves as Chairman of our Board of Directors and Chief Executive Officer. The employment agreement provides that Mr. Sokol is to receive an annual base salary of not less than $750,000, senior executive employee benefits and annual bonus awards that shall not be less than $675,000. The agreement is currently scheduled to expire on

August 21, 2007, but renews automatically from year to year subject to Mr. Sokol's election to decline renewal at least 120 days prior to such date or termination by us.

The employment agreement provides that we may terminate the employment of Mr. Sokol with cause, in which case we are to pay to him any accrued but unpaid salary and a bonus of not less than the minimum annual bonus, or due to death, permanent disability or other than for cause, including a change in control, in which case Mr. Sokol is entitled to receive an amount equal to three times the sum of his annual salary then in effect and the greater of his minimum annual bonus or his average annual bonus for the two preceding years, as well as three years of accelerated option vesting plus continuation of his senior executive employee benefits (or the economic equivalent thereof) for three years. If Mr. Sokol resigns, we are to pay to him any accrued but unpaid salary and a bonus of not less than the annual minimum bonus, unless he resigns for good reason in which case he will receive the same benefits as if he were terminated other than for cause.

In the event Mr. Sokol has relinquished his position as Chief Executive Officer and is subsequently terminated as Chairman of the Board due to death, disability or other than for cause, he is entitled to (i) any accrued but unpaid salary plus an amount equal to the aggregate annual 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, (ii) the immediate vesting of all of his options, and (iii) the continuation of his senior executive employee benefits (or the economic equivalent thereof) through such fifth anniversary. If Mr. Sokol relinquishes his position as Chief Executive Officer but offers to remain employed as the Chairman of the Board, he is to receive a special achievement bonus equal to two times the sum of his annual salary then in effect and the greater of his minimum annual bonus or his average annual bonus for the two preceding years, as well as two years of accelerated option vesting.

Under the terms of separate employment agreements with us, each of Messrs. Abel and Goodman is entitled to receive two years base salary continuation, payments in respect of average bonuses for the prior two years and two years continued option vesting in the event we terminate his employment other than for cause. If such persons were terminated without cause, Messrs. Sokol, Abel and Goodman would currently be entitled to be paid approximately $10,050,000, $5,880,000 and $1,215,000, respectively, without giving effect to any tax-related provisions.

Compensation Committee Interlocks and Insider Participation

The compensation committee of the Board of Directors is comprised of Messrs. Warren E. Buffett and Walter Scott, Jr. Mr. Walter Scott, Jr. is a former officer of ours.

Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

We are a consolidated subsidiary of Berkshire Hathaway, which owns 88.2% (86.6% on a diluted basis) of our outstanding common stock. The remainder of our common stock is owned by a private investor group comprised of Walter Scott, Jr., one of our directors, Mr. Sokol, our Chairman and Chief Executive Officer and Mr. Abel, our President and Chief Operating Officer.

The following table sets forth certain information regarding beneficial ownership of the shares of our common stock by each of our directors, our Named Executive Officers and all directors and executive officers as a group as of June 30, 2006.

Name and Address of Beneficial Owner(1)	Number of Shares Beneficially Owned(2)	Percentage Of Class(2)
Berkshire Hathaway(3)	65,433,130	88.23%
Walter Scott, Jr.(4)	5,172,000	6.97%
David L. Sokol(5)	1,179,208	1.57%
Gregory E. Abel(6)	749,992	1.00%
Douglas L. Anderson	—	—
Warren E. Buffett(7)	—	—
Patrick J. Goodman	—	—
Marc D. Hamburg(7)	—	—
Maureen E. Sammon	—	—
All directors and executive officers as a group (8 persons)	7,101,200	9.40%

(1) Unless otherwise indicated, each address is c/o MEHC 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) Such beneficial owner's address is 1440 Kiewit Plaza, Omaha, Nebraska 68131.

(4) Excludes 3,000,000 shares held by family members and family controlled trusts and corporations (or Scott Family Interests) as to which Mr. Scott disclaims beneficial ownership. Such beneficial owner's address is 1000 Kiewit Plaza, Omaha, Nebraska 68131.

(5) Includes options to purchase 749,277 shares of common stock that are exercisable within 60 days.

(6) Includes options to purchase 649,052 shares of common stock which are exercisable within 60 days. Excludes 10,041 shares reserved for issuance pursuant to a deferred compensation plan.

(7) Excludes 65,433,130 shares of common stock held by Berkshire Hathaway of which beneficial ownership of such shares is disclaimed.

Table of Contents

The following table sets forth certain information regarding beneficial ownership of the Class A and Class B shares of Berkshire Hathaway's common stock by each of our directors, our Named Executive Officers and all directors and executive officers as a group as of June 30, 2006.

Name and Address of Beneficial Owner(1)	Number of Shares Beneficially Owned(2)	Percentage Of Class(2)
Walter Scott, Jr.(3)		
Class A	100	*
Class B	—	—
David L. Sokol		
Class A	207	*
Class B	100	*
Gregory E. Abel		
Class A	—	—
Class B	—	—
Douglas L. Anderson		
Class A	3	*
Class B	—	—
Warren E. Buffett(4)		
Class A	498,320	39.50%
Class B	177	*
Patrick J. Goodman		
Class A	2	*
Class B	—	—
Marc D. Hamburg		
Class A	—	—
Class B	—	—
Maureen E. Sammon		
Class A	—	—
Class B	21	*
All directors and executive officers as a group (8 persons)		
Class A	498,632	39.50%
Class B	298	*

* Less than 1%

(1) Unless otherwise indicated, each address is c/o MEHC 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. Such beneficial owner's address is 1440 Kiewit Plaza, Omaha, Nebraska 68131.

(4) Includes 474,998 Class A shares owned directly and beneficially by Warren E. Buffett, and 23,322 Class A shares and 177 Class B shares owned by the estate of Susan T. Buffett of which Mr. Buffett is the executor but with respect to which Mr. Buffett disclaims any beneficial interest. Such beneficial owner's address is 1440 Kiewit Plaza, Omaha, Nebraska 68131.

Table of Contents

Mr. Sokol's employment agreement gives him the right during the term of his employment to serve as a member of our Board of Directors and to nominate two additional directors.

Pursuant to a shareholders agreement, as amended on December 7, 2005, Walter Scott, Jr. or any of the Scott Family Interests and Messrs. Sokol and 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.

Certain Relationships and Related Transactions

Under a subscription agreement with us, which expires in March 2007, Berkshire Hathaway has agreed to purchase, under certain circumstances, additional 11% trust issued mandatorily redeemable preferred securities in the event that certain outstanding trust preferred securities of ours which were outstanding prior to the closing of our acquisition by a private investor group on March 14, 2000 are tendered for conversion to cash by the current holders.

In order to finance our acquisition of Northern Natural Gas, on August 16, 2002, we sold to Berkshire Hathaway $950.0 million in aggregate principal amount of the 11% mandatorily redeemable trust issued preferred securities Series A, of our subsidiary trust, MidAmerican Capital Trust II, due August 31, 2012. The transaction was a private placement pursuant to Section 4(1) of the Securities Act and did not involve any underwriters, underwriting discounts or commissions. Scheduled principal payments began in August 2003. Messrs. Warren E. Buffett and Walter Scott, Jr. are members of the

Board of Directors of Berkshire Hathaway. Messrs. Buffett and Marc D. Hamburg are executive officers of Berkshire Hathaway.

On February 9, 2006, following the effective date of the repeal of PUHCA 1935, Berkshire Hathaway converted its 41,263,395 shares of our no par, zero-coupon convertible preferred stock into an equal number of shares of our common stock. As a consequence, Berkshire Hathaway owns in excess of 80.0% of our outstanding common stock, consolidates us in its financial statements as a majority-owned subsidiary, and includes us in its consolidated federal U.S. income tax return.

On March 1, 2006, we and Berkshire Hathaway entered into the Berkshire Equity Commitment pursuant to which Berkshire Hathaway has agreed to purchase up to $3.5 billion of our common equity upon any requests authorized from time to time by our Board of Directors. The proceeds of any such equity contribution shall only be used for the purpose of (a) paying when due our debt obligations and (b) funding the general corporate purposes and capital requirements of our regulated subsidiaries. Berkshire Hathaway will have up to 180 days to fund any such request. The Berkshire Equity Commitment will expire on February 28, 2011, was not used for the PacifiCorp acquisition and will not be used for future acquisitions.

On March 21, 2006, Berkshire Hathaway and certain other of our existing stockholders and related companies invested $5,109.5 million, in the aggregate, in 35,237,931 shares of our common stock in order to provide equity funding for the PacifiCorp acquisition. The per-share value assigned to the shares of common stock issued, which were effected pursuant to a private placement and were exempt from the registration requirements of the Securities Act of 1933, as amended, was based on an assumed fair market value as agreed to by our stockholders.

On March 28, 2006, we repurchased 11,724,138 shares of our common stock from Berkshire Hathaway for an aggregate purchase price of $1,700.0 million.

Table of Contents

DESCRIPTION OF THE BONDS

The initial 2006 bonds were, and the exchange 2006 bonds, will be, issued pursuant to a supplemental indenture, to the indenture, dated as of October 4, 2002 and amended as of March 24, 2006, between MidAmerican Energy Holdings Company, or MEHC, and The Bank of New York Trust Company, N.A., as trustee. The term ‘‘indenture’’ when used in this prospectus will refer to the indenture as amended by all supplemental indentures executed and delivered on or prior to the date on which the bonds are issued and sold. The terms of the bonds include those stated in the indenture and those made part of the indenture by reference to the Trust Indenture Act of 1939, as amended.

On October 4, 2002, MEHC issued $200,000,000 of its 4.625% Senior Notes due 2007 (hereafter referred to as the series A notes) and $500,000,000 of its 5.875% Senior Notes due 2012 (hereafter referred to as the series B notes) and, on May 16, 2003, MEHC issued $450,000,000 of its 3.50% Senior Notes due 2008 (hereafter referred to as the series C notes), and on February 12, 2004, MEHC issued $250,000,000 of its 5.00% Senior Notes due 2014 (hereinafter referred to as the series D notes) in each case pursuant to the indenture. Unless otherwise indicated, references hereafter to the securities in this prospectus include the series A notes, the series B notes, the series C notes, the series D notes and the bonds (and any other series of notes, bonds or other securities hereafter issued under a supplemental indenture or otherwise pursuant to the indenture).

The following description is a summary of the material provisions of the indenture and the related registration rights agreement. It does not restate those agreements in their entirety. We urge you to read the indenture and the registration rights agreement because they, and not this description, define your rights as a holder of the bonds. The definitions of certain capitalized terms used in the following summary are set forth below under ‘‘— Definitions.’’

General

The indenture does not limit the aggregate principal amount of the debt securities that may be issued thereunder and provides that debt securities may be issued from time to time in one or more series.

The initial 2006 bonds were initially offered in the aggregate principal amount of $1,700,000,000. MEHC may, without the consent of the holders, increase such principal amount in the future on the same terms and conditions (except for the issue date and issue price) and with the same CUSIP number(s) as the 2006 bonds.

The initial 2006 bonds were, and the exchange 2006 bonds will be, issued in one series, will bear interest at the rate of 6.125% per annum and will mature on April 1, 2036. Interest on the 2006 bonds is payable semi-annually in arrears on each April 1 and October 1, commencing October 1, 2006, to the holders thereof at the close of business on the preceding March 15 and September 15, respectively. Interest on the bonds will be computed on the basis of a 360-day year of twelve 30-day months.

The initial 2006 bonds were and the exchange 2006 bonds will be, issued without coupons and in fully registered form only in denominations of $2,000 and any integral multiple of $1,000 in excess thereof.

MEHC files certain reports and other information with the SEC in accordance with the requirements of Sections 13 and 15(d) under the Exchange Act. See ‘‘Where You Can Find More Information.’’ In addition, at any time that Sections 13 and 15(d) cease to apply to MEHC, MEHC will covenant in the indenture to file comparable reports and information with the trustee and the SEC, and mail such reports and information to holders of securities at their registered addresses, for so long as any securities remain outstanding.

If (i) a registration statement of which this prospectus is a part is not declared effective by the SEC within 270 days after the closing date for the initial 2006 bonds, (ii) a shelf registration statement with respect to the resale of the bonds is not declared effective by the SEC within 150 days after MEHC’s obligation to file such shelf registration statement arises (but in any event not prior to

270 days after the closing date for the initial 2006 bonds) or (iii) any of the foregoing registration statements (or the prospectuses related thereto) after being declared effective by the SEC cease to be so effective or usable (subject to certain exceptions) in connection with resales of the initial 2006 bonds or exchange 2006 bonds for the periods specified and in accordance with the registration rights agreement, the interest rate on the bonds that are then subject to such cessation or other registration default will increase by 0.5% from and including the date on which any such event occurs until such event ceases to be continuing. The exchange offer and the registration rights are more fully described under ''Exchange Liquidated Damages''.

Any initial 2006 bonds that remain outstanding after the consummation of the exchange offer, together with all exchange 2006 bonds issued in connection with the exchange offer, will be treated as a single class of securities under the indenture.

Optional Redemption

General

The bonds will be redeemable in whole or in part, at the option of MEHC at any time, at a redemption price equal to the greater of:

(1) 100% of the principal amount of the bonds being redeemed; or

(2) the sum of the present values of the remaining scheduled payments of principal of and interest on the bonds being redeemed discounted to the date of redemption on a semiannual basis (assuming a 360-day year consisting of twelve 30-day months) at a discount rate equal to the Treasury Yield plus 25 basis points,

plus, for (1) or (2) above, whichever is applicable, accrued interest on such bonds to the date of redemption.

Notice of redemption shall be given not less than 30 days nor more than 60 days prior to the date of redemption. If fewer than all of the bonds are to be redeemed, the selection of the bonds for redemption will be made by the trustee pro rata among all outstanding bonds.

Unless MEHC defaults in payment of the Redemption Price (as defined below), from and after the date of redemption the bonds or portions of bonds called for redemption will cease to bear interest, and the holders of those bonds will have no right in respect of those bonds except the right to receive the applicable Redemption Price.

Optional Redemption Provisions

Under the procedures described above, the price payable upon the optional redemption at any time of a bond (the ''Redemption Price'') is determined by calculating the present value (the ''Present Value'') at such time of each remaining payment of principal of or interest on such bond and then totaling those Present Values. If the sum of those Present Values is equal to or less than 100% of the principal amount of such bond, the Redemption Price of such bond will be 100% of its principal amount (redemption at par). If the sum of those Present Values is greater than 100% of the principal amount of such bond, the Redemption Price of such bond will be such greater amount (redemption at a premium). In no event may a bond be redeemed optionally at less than 100% of its principal amount.

The Present Value at any time of a payment of principal of or interest on a bond is calculated by applying to such payment the discount rate (the ''Discount Rate'') applicable to such payment. The Discount Rate applicable at any time to payment of principal of or interest on a bond equals the equivalent yield to maturity at such time of a fixed rate United States treasury security having a maturity comparable to the maturity of such payment plus 25 basis points, such yield being calculated on the basis of the interest rate borne by such United States treasury security and the price at such time of such security. The United States treasury security employed in the calculation of a Discount Rate (a ''Relevant Security'') as well as the price and equivalent yield to maturity of such Relevant Security will be selected or determined by an Independent Investment Banker.

Whether the sum of the Present Values of the remaining payments of principal of and interest on a bond to be redeemed optionally will or will not exceed 100% of its principal amount and, accordingly, whether such bond will be redeemed at par or at a premium will depend on the Discount Rate used to calculate such Present Values. Such Discount Rate, in turn, will depend upon the equivalent yield to maturity of a Relevant Security, which yield will itself depend on the interest rate borne by, and the price of, the Relevant Security. While the interest rate borne by the Relevant Security is fixed, the price of the Relevant Security tends to vary with interest rate levels prevailing from time to time. In general, if at a particular time the prevailing level of interest rates for a newly issued United States treasury security having a maturity comparable to that of a Relevant Security is higher than the level of interest rates for newly issued United States treasury securities having a maturity comparable to such Relevant Security prevailing at the time the Relevant Security was issued, the price of the Relevant Security will be lower than its issue price. Conversely, if at a particular time the prevailing level of interest rates for a newly issued United States treasury security having a maturity comparable to that of a Relevant Security is lower than the level of interest rates prevailing for newly issued United States treasury securities having a maturity comparable to the Relevant Security at the time the Relevant Security was issued, the price of the Relevant Security will be higher than its issue price.

Because the equivalent yield to maturity on a Relevant Security depends on the interest rate it bears and its price, an increase or a decrease in the level of interest rates for newly issued United States treasury securities with a maturity comparable to that of a Relevant Security above or below the levels of interest rates for newly issued United States treasury securities having a maturity comparable to the Relevant Security prevailing at the time of issue of the Relevant Security will generally result in an increase or a decrease, respectively, in the Discount Rate used to determine the Present Value of a payment of principal of or interest on a bond. An increase or a decrease in the Discount Rate, and therefore an increase or a decrease in the levels of interest rates for newly issued United States treasury securities having a maturity comparable to the Relevant Security, will result in a decrease or an increase, respectively, of the Present Value of a payment of principal of or interest on a bond. In other words, the Redemption Price varies inversely with the levels of interest rates for newly issued United States treasury securities having a maturity comparable to the Comparable Treasury Issue. As noted above, however, if the sum of the Present Values of the remaining payments of principal of and interest on a bond proposed to be redeemed is less than its principal amount, such bond may only be redeemed at par.

Sinking Fund

The bonds will not be subject to any mandatory sinking fund.

Ranking

The bonds are general, unsecured senior obligations of MEHC and will rank *pari passu* in right of payment with all other existing and future senior unsecured obligations of MEHC (including the series A notes, series B notes, series C notes and series D notes) and senior in right of payment to all existing and future subordinated obligations of MEHC. The bonds will be effectively subordinated to all existing and future secured obligations of MEHC and to all existing and future obligations of MEHC's Subsidiaries. At June 30, 2006, MEHC outstanding senior indebtedness was $4.5 billion and MEHC's outstanding subordinated indebtedness, which consists of MEHC's trust preferred securities, was $1.5 billion. These amounts exclude MEHC's guarantees and letters of credit in respect of Subsidiary and equity investment indebtedness aggregating $112.5 million as of June 30, 2006. MEHC's Subsidiaries also have significant amounts of indebtedness. At June 30, 2006, MEHC's consolidated Subsidiaries had outstanding indebtedness totaling approximately $11.4 billion. This amount does not include (i) any trade debt or preferred stock obligations of MEHC's Subsidiaries, (ii) MEHC's Subsidiaries' letters of credit in respect of their indebtedness or (iii) MEHC's share of the outstanding indebtedness of its and its Subsidiaries' equity investments.

Table of Contents

Covenants

Except as set forth under ''— Defeasance and Discharge — Covenant Defeasance'' below, for so long as any securities remain outstanding, MEHC will comply with the terms of the covenants set forth below.

Restrictions on Liens

MEHC is will not be permitted to pledge, mortgage, hypothecate or permit to exist any pledge, mortgage or other Lien upon any property or assets at any time directly owned by MEHC to secure any indebtedness for money borrowed which is incurred, issued, assumed or guaranteed by MEHC (''Indebtedness for Borrowed Money''), without making effective provisions whereby the outstanding securities will be equally and ratably secured with any and all such Indebtedness for Borrowed Money and with any other Indebtedness for Borrowed Money similarly entitled to be equally and ratably secured; *provided*, *however*, that this restriction will not apply to or prevent the creation or existence of:

(1) any Liens existing prior to the issuance of the securities;

(2) purchase money Liens which do not exceed the cost or value of the purchased property or assets;

(3) any Liens not to exceed 10% of Consolidated Net Tangible Assets; and

(4) any Liens on property or assets granted in connection with extending, renewing, replacing or refinancing in whole or in part the Indebtedness for Borrowed Money (including, without limitation, increasing the principal amount of such Indebtedness for Borrowed Money) secured by Liens described in the foregoing clauses (1) through (3), *provided* that the Liens in connection with any such extension, renewal, replacement or refinancing will be limited to the specific property or assets that was subject to the original Lien.

In the event that MEHC proposes to pledge, mortgage or hypothecate or permit to exist any pledge, mortgage or other Lien upon any property or assets at any time directly owned by it to secure any Indebtedness for Borrowed Money, other than as permitted by clauses (1) through (4) of the previous paragraph, MEHC will give prior written notice thereof to the trustee and MEHC will, prior to or simultaneously with such pledge, mortgage or hypothecation, effectively secure all the securities equally and ratably with such Indebtedness for Borrowed Money.

The foregoing covenant will not restrict the ability of MEHC's Subsidiaries and affiliates to pledge, mortgage, hypothecate or permit to exist any mortgage, pledge or Lien upon their property or assets, in connection with project financings or otherwise.

Consolidation, Merger, Conveyance, Sale or Lease

So long as any securities are outstanding, MEHC is not permitted to consolidate with or merge with or into any other person, or convey, transfer or lease its consolidated properties and assets substantially as an entirety to any person, or permit any person to merge into or consolidate with MEHC, unless (1) MEHC is the surviving or continuing corporation or the surviving or continuing corporation or purchaser or lessee is a corporation incorporated under the laws of the United States of America, one of the states thereof or the District of Columbia or Canada and assumes MEHC's obligations under the securities and under the indenture and (2) immediately before and after such transaction, no event of default under the indenture shall have occurred and be continuing.

Except for a sale of the consolidated properties and assets of MEHC substantially as an entirety as provided above, and other than properties or assets required to be sold to conform with laws or governmental regulations, MEHC is not permitted, directly or indirectly, to sell or otherwise dispose of any of its consolidated properties or assets (other than short-term, readily marketable investments purchased for cash management purposes with funds not representing the proceeds of other asset sales) if on a pro forma basis, the aggregate net book value of all such sales during the most recent

12-month period would exceed 10% of Consolidated Net Tangible Assets computed as of the end of the most recent quarter preceding such sale; *provided*, *however*, that (1) any such sales shall be disregarded for purposes of this 10% limitation if the net proceeds are invested in properties or assets in similar or related lines of business of MEHC and its Subsidiaries, including, without limitation, any of the lines of business in which MEHC or any of its Subsidiaries is engaged on the date of such sale or disposition, and (2) MEHC may sell or otherwise dispose of consolidated properties and assets in excess of such 10% limitation if the net proceeds from such sales or dispositions, which are not reinvested as provided above, are retained by MEHC as cash or Cash Equivalents or used to retire Indebtedness for Borrowed Money of MEHC (other than Indebtedness for Borrowed Money which is subordinated to the securities) and its Subsidiaries.

The covenant described immediately above includes a phrase relating to a conveyance, transfer or lease of our consolidated properties and assets ‘‘substantially as an entirety.’’ Although there is a limited body of case law interpreting the phrase ‘‘substantially as an entirety,’’ there is no precise established definition of the phrase under applicable law. Accordingly, the nature and extent of the restriction on our ability to convey, transfer or lease our consolidated properties or assets substantially as an entirety, and the protections provided to the holders of securities by such restriction, may be uncertain.

Purchase of Securities Upon a Change of Control

Upon the occurrence of a Change of Control, each holder of the securities will have the right to require that MEHC repurchase all or any part of such holder’s securities at a purchase price in cash equal to 101% of the principal thereof on the date of purchase plus accrued interest, if any, to the date of purchase.

The Change of Control provisions may not be waived by the trustee or by the board of directors of MEHC, and any modification thereof must be approved by each holder. Nevertheless, the Change of Control provisions will not necessarily afford protection to holders, including protection against an adverse effect on the value of the securities of any series, including the bonds, in the event that MEHC or its Subsidiaries incur additional Debt, whether through recapitalizations or otherwise.

Within 30 days following a Change of Control, MEHC will mail a notice to each holder of the securities with a copy to the trustee, stating the following:

(1) that a Change of Control has occurred and that such holder has the right to require MEHC to purchase such holder’s securities at the purchase price described above (the ‘‘Change of Control Offer’’);

(2) the circumstances and relevant facts regarding such Change of Control (including information with respect to pro forma historical income, cash flow and capitalization after giving effect to such Change of Control);

(3) the purchase date (which will be not earlier than 30 days nor later than 60 days from the date such notice is mailed) (the ‘‘Purchase Date’’);

(4) that after the Purchase Date interest on such security will continue to accrue (except as provided in clause (5));

(5) that any security properly tendered pursuant to the Change of Control Offer will cease to accrue interest after the Purchase Date (assuming sufficient moneys for the purchase thereof are deposited with the trustee);

(6) that holders electing to have a security purchased pursuant to a Change of Control Offer will be required to surrender the security, with the form entitled ‘‘Option of Holder To Elect Purchase’’ on the reverse of the security completed, to the paying agent at the address specified in the notice prior to the close of business on the fifth business day prior to the Purchase Date;

(7) that a holder will be entitled to withdraw such holder’s election if the paying agent receives, not later than the close of business on the third business day (or such shorter periods as may be required by applicable law) preceding the Purchase Date, a telegram, telex, facsimile transmission or letter setting forth the name of the holder, the principal amount of securities the holder delivered for purchase, and a statement that such holder is withdrawing his election to have such securities of such series purchased; and

(8) that holders that elect to have their securities purchased only in part will be issued new securities having a principal amount equal to the portion of the securities that were surrendered but not tendered and purchased.

On the Purchase Date, MEHC will (1) accept for payment all securities or portions thereof tendered pursuant to the Change of Control Offer, (2) deposit with the trustee money sufficient to pay the purchase price of all securities or portions thereof so tendered for purchase and (3) deliver or cause to be delivered to the trustee the securities properly tendered together with an officer’s certificate identifying the securities or portions thereof tendered to MEHC for purchase. The trustee will promptly mail, to the holders of the securities properly tendered and purchased, payment in an amount equal to the purchase price, and promptly authenticate and mail to each holder a new security having a principal amount equal to any portion of such holder’s securities that were surrendered but not tendered and purchased. MEHC will publicly announce the results of the Change of Control Offer on or as soon as practicable after the Purchase Date.

If MEHC is prohibited by applicable law from making the Change of Control Offer or purchasing securities of any series, including the bonds, thereunder, MEHC need not make a Change of Control Offer pursuant to this covenant for so long as such prohibition is in effect.

MEHC will comply with all applicable tender offer rules, including, without limitation, Rule 14e-1 under the Exchange Act, in connection with a Change of Control Offer.

Events of Default

An event of default with respect to the securities of any series, including the bonds, will be defined in the indenture as being any one of the following events:

(1) default as to the payment of principal of, or premium, if any, on any security of that series or as to any payment required in connection with a Change of Control;

(2) default as to the payment of interest on any security of that series for 30 days after payment is due;

(3) failure to make a Change of Control Offer required under the covenants described under ''Purchase of Securities Upon a Change of Control'' above or a failure to purchase the securities of that series tendered in respect of such Change of Control Offer;

(4) default in the performance, or breach, of any covenant, agreement or warranty of MEHC contained in the indenture and the securities of that series and such failure continues for 30 days after written notice is given to MEHC by the trustee or to MEHC and the trustee by the holders of at least a majority in aggregate principal amount outstanding of the securities of that series, as provided in the indenture;

(5) default on any other Debt of MEHC or any Significant Subsidiary (other than Debt that is Non-Recourse to MEHC) if either (x) such default results from failure to pay principal of such Debt in excess of $100 million when due after any applicable grace period or (y) as a result of such default, the maturity of such Debt has been accelerated prior to its scheduled maturity and such default has not been cured within the applicable grace period, and such acceleration has not been rescinded, and the principal amount of such Debt, together with the principal amount of any other Debt of MEHC and its Significant Subsidiaries (not including Debt that is Non-Recourse to MEHC) that is in default as to principal, or the maturity of which has been accelerated, aggregates $100 million or more;

(6) the entry by a court of one or more judgments or orders against MEHC or any Significant Subsidiary for the payment of money that in the aggregate exceeds $100 million (excluding (i) the amount thereof covered by insurance or by a bond written by a person other than an affiliate of MEHC (other than, with respect to the series C or D notes and the bonds, Berkshire Hathaway or any of its affiliates that provide commercial insurance in the ordinary course of their business) and (ii) judgments that are Non-Recourse to MEHC), which judgments or orders have not been vacated, discharged or satisfied or stayed pending appeal within 60 days from the entry thereof, *provided* that such a judgment or order will not be an event of default if such judgment or order does not require any payment by MEHC; and

(7) certain events involving bankruptcy, insolvency or reorganization of MEHC or any of its Significant Subsidiaries.

The indenture provides that the trustee may withhold notice to the holders of any default (except in payment of principal of, premium, if any, or interest on any series of securities and any payment required in connection with a Change of Control) if the trustee considers it in the interest of holders to do so.

The indenture provides that if an event of default with respect to the securities of any series at the time outstanding, including the bonds (other than an event of bankruptcy, insolvency or reorganization of MEHC or a Significant Subsidiary) has occurred and is continuing, either the trustee or (i) in the case of any event of default described in clause (1) or (2) above, the holders of at least 33% in aggregate principal amount of the securities of that series then outstanding, or (ii) in the case of any other event of default, the holders of at least a majority in aggregate principal amount of the securities of that series then outstanding, may declare the principal of and any accrued interest on all securities of that series to be due and payable immediately, but upon certain conditions such declaration may be annulled and past defaults (except, unless theretofore cured, a default in payment of principal of, premium, if any, or interest on the securities of that series or any payment required in connection with a Change of Control) may be waived by the holders of a majority in principal amount of the securities of that series then outstanding. If an event of default due to the bankruptcy, insolvency or reorganization of MEHC or a Significant Subsidiary occurs, the indenture provides that the entire principal amount of and any interest accrued on all securities will become immediately due and payable without any action by the trustee, the holders of securities or any other person.

The holders of a majority in principal amount of the securities of any series then outstanding, including the 2006 bonds, will have the right to direct the time, method and place of conducting any proceeding for any remedy available to the trustee under the indenture with respect to the securities of such series, subject to certain limitations specified in the indenture, *provided* that the holders of securities of such series must have offered to the trustee reasonable indemnity against expenses and liabilities.

The indenture requires the annual filing by MEHC with the trustee of a written statement as to its knowledge of the existence of any default in the performance and observance of any of the covenants contained in the indenture.

Modification of the Indenture

The indenture contains provisions permitting MEHC and the trustee, with the consent of the holders of not less than a majority in principal amount of the outstanding securities of each series affected by the modification, including the bonds, to modify the indenture or the rights of the holders of such series, except that no such modification may (1) extend the stated maturity of the principal of or any installment of interest on the securities, reduce the principal amount thereof or the interest rate thereon, reduce any premium payable on redemption or purchase thereof, impair the right of any holder to institute suit for the enforcement of any such payment on or after the stated maturity thereof or make any change in the covenants regarding a Change of Control or the related definitions without the consent of the holder of each outstanding security so affected, or (2) reduce the percentage of any series of securities, the consent of the holders of which is required for any such modification, without the consent of the holders of all series of securities then outstanding.

Table of Contents

Defeasance and Discharge

Legal Defeasance

The indenture provides that MEHC will be deemed to have paid and will be discharged from any and all obligations in respect of the bonds or any other series of securities issued thereunder on the 123rd day after the deposit referred to below has been made (or immediately if an opinion of counsel is delivered to the effect described in clause (B)(3)(y) below), and the provisions of the indenture will cease to be applicable with respect to the securities of such series (except for, among other matters, certain obligations to register the transfer or exchange of the securities of such series, to replace stolen, lost or mutilated securities of such series, to maintain paying agents and to hold monies for payment in trust) if, among other things:

(A) MEHC has deposited with the trustee, in trust, money and/or U.S. Government Obligations that through the payment of interest and principal in respect thereof in accordance with their terms will provide money in an amount sufficient to pay the principal of, premium, if any, and accrued and unpaid interest on the applicable securities, on the respective stated maturities of the securities or, if MEHC makes arrangements satisfactory to the trustee for the redemption of the securities prior to their stated maturity, on any earlier redemption date in accordance with the terms of the indenture and the applicable securities;

(B) MEHC has delivered to the trustee:

(1) either (x) an opinion of counsel to the effect that holders of securities of such series will not recognize income, gain or loss for federal income tax purposes as a result of such deposit, defeasance and discharge and will be subject to federal income tax on the same amount and in the same manner and at the same times as would have been the case if such deposit, defeasance and discharge had not occurred and MEHC had paid or redeemed such securities on the applicable dates, which opinion of counsel must be based upon a ruling of the Internal Revenue Service (''IRS'') to the same effect or a change in applicable federal income tax law or related Treasury regulations after the date of the indenture, or (y) a ruling directed to the trustee or MEHC received from the IRS to the same effect as the aforementioned opinion of counsel;

(2) an opinion of counsel to the effect that the creation of the defeasance trust does not violate the Investment Company Act of 1940; and

(3) an opinion of counsel to the effect that either (x) after the passage of 123 days following the deposit referred to in clause (A) above, the trust fund will not be subject to the effect of Section 547 or 548 of the U.S. Bankruptcy Code or Section 15 of the New York Debtor and Creditor Law or (y) based upon existing precedents, if the matter were properly briefed, a court should hold that the deposit of moneys and/or U.S. Government Obligations as provided in clause (A) above would not constitute a preference voidable under Section 547 or 548 of the U.S. Bankruptcy Code or Section 15 of the New York Debtor and Creditor Law;

(C) if at such time the securities are listed on a national securities exchange, MEHC has delivered to the trustee an opinion of counsel to the effect that the securities will not be delisted as a result of such deposit, defeasance and discharge; and

(D) immediately after giving effect to such deposit referred to in clause (A) above on a pro forma basis, no event of default under the indenture, or event that after the giving of notice or lapse of time or both would become an event of default, will have occurred and be continuing on the date of such deposit or (unless an opinion of counsel is delivered to the effect described in clause (B)(3)(y) above) during the period ending on the 123rd day after the date of such deposit, and such deposit and discharge will not result in a breach or violation of, or constitute a default under, any other material agreement or instrument to which MEHC is a party or by which MEHC is bound.

Table of Contents

Covenant Defeasance

The indenture further provides that the provisions of the covenants described herein under ''Covenants – Restrictions on Liens,'' ''— Consolidation, Merger, Conveyance, Sale or Lease'' and ''— Purchase of Securities Upon a Change of Control,'' clauses (3) and (4) under ''Events of Default'' with respect to such covenants, clause (2) under ''Events of Default'' with respect to offers to purchase upon a Change of Control as described above and clauses (5) and (6) under ''Events of Default'' will cease to be applicable to MEHC and its Subsidiaries upon the satisfaction of the provisions described in clauses (A), (B), (C) and (D) of the preceding paragraph; *provided, however*, that with respect to such covenant defeasance, the opinion of counsel described in clause (B)(1)(x) above need not be based upon any ruling of the IRS or change in applicable federal income tax law or related Treasury regulations.

Defeasance and Certain Other Events of Default

If MEHC exercises its option to omit compliance with certain covenants and provisions of the indenture with respect to the securities of any series, including the bonds, as described in the immediately preceding paragraph and any series of securities is declared due and payable because of the occurrence of an event of default that remains applicable, the amount of money and/or U.S. Government Obligations on deposit with the trustee will be sufficient to pay amounts due on such securities at the time of their stated maturity or scheduled redemption, but may not be sufficient to pay amounts due on such securities at the time of acceleration resulting from such event of default. MEHC will remain liable for such payments.

Governing Law

The indenture and the securities will be governed by, and construed in accordance with, the law of the State of New York, including Section 5-1401 of the New York General Obligations Law, but otherwise without regard to conflict of laws rules.

Trustee

The Bank of New York Trust Company, N.A. is the trustee under the indenture. The Bank of New York Trust Company, N.A. (or one of its affiliates) currently serves, and may in the future serve, as trustee under indentures evidencing other indebtedness of MEHC and its affiliates. The Bank of New York Trust Company, N.A. (or one of its affiliates) is also, and may in the future be, a lender under credit facilities for MEHC and its affiliates.

Definitions

Set forth below is a summary of certain of the defined terms used in the covenants and other provisions of the indenture. Reference is made to the indenture for the full definitions of all such terms as well as any other capitalized terms used herein for which no definition is provided.

''Attributable Value'' means, as to a Capitalized Lease Obligation under which any person is at the time liable and at any date as of which the amount thereof is to be determined, the capitalized amount thereof that would appear on the face of a balance sheet of such person in accordance with GAAP.

''Berkshire Hathaway'' means Berkshire Hathaway Inc. and any Subsidiary of Berkshire Hathaway Inc.

''Capital Stock'' means, with respect to any person, any and all shares, interests, participations or other equivalents (however designated, whether voting or non-voting) in, or interests (however designated) in, the equity of such person that is outstanding or issued on or after the date of the indenture, including, without limitation, all common stock and preferred stock and partnership and joint venture interests in such person.

''Capitalized Lease'' means, as applied to any person, any lease of any property of which the discounted present value of the rental obligations of such person as lessee, in conformity with GAAP,

---

is required to be capitalized on the balance sheet of such person, and ''Capitalized Lease Obligation'' means the rental obligations, as aforesaid, under any such lease.

''Cash Equivalent'' means any of the following:

(1) securities issued or directly and fully guaranteed or insured by the United States or any agency or instrumentality thereof (*provided* that the full faith and credit of the United States is pledged in support thereof);

(2) time deposits and certificates of deposit of any commercial bank organized in the United States having capital and surplus in excess of $500,000,000 or any commercial bank organized under the laws of any other country having total assets in excess of $500,000,000 with a maturity date not more than two years from the date of acquisition;

(3) repurchase obligations with a term of not more than 30 days for underlying securities of the types described in clauses (1) or (5) of this definition that were entered into with any bank meeting the qualifications set forth in clause (2) of this definition or another financial institution of national reputation;

(4) direct obligations issued by any state or other jurisdiction of the United States or any other country or any political subdivision or public instrumentality thereof maturing, or subject to tender at the option of the holder thereof, within 90 days after the date of acquisition thereof and, at the time of acquisition, having a rating of at least A from S&P or A-2 from Moody's (or, if at any time neither S&P nor Moody's may be rating such obligations, then from another nationally recognized rating service acceptable to the trustee);

(5) commercial paper issued by (a) the parent corporation of any commercial bank organized in the United States having capital and surplus in excess of $500,000,000 or any commercial bank organized under the laws of any other country having total assets in excess of $500,000,000, and (b) others having one of the two highest ratings obtainable from either S&P or Moody's (or, if at any time neither S&P nor Moody's may be rating such obligations, then from another nationally recognized rating service acceptable to the trustee) and in each case maturing within one year after the date of acquisition;

(6) overnight bank deposits and bankers' acceptances at any commercial bank organized in the United States having capital and surplus in excess of $500,000,000 or any commercial bank organized under the laws of any other country having total assets in excess of $500,000,000;

(7) deposits available for withdrawal on demand with any commercial bank organized in the United States having capital and surplus in excess of $500,000,000 or any commercial bank organized under the laws of any other country having total assets in excess of $500,000,000;

(8) investments in money market funds substantially all of whose assets comprise securities of the types described in clauses (1) through (6) and (9) of this definition; and

(9) auction rate securities or money market preferred stock having one of the two highest ratings obtainable from either S&P or Moody's (or, if at any time neither S&P nor Moody's may be rating such obligations, then from another nationally recognized rating service acceptable to the trustee).

‘‘Change of Control’’ means the occurrence of one or more of the following events:

(1) a transaction pursuant to which Berkshire Hathaway ceases to own, on a diluted basis, at least a majority of the issued and outstanding common stock of MEHC; or

(2) MEHC or its Subsidiaries sell, convey, assign, transfer, lease or otherwise dispose of all or substantially all the property of MEHC and its Subsidiaries taken as a whole to any person or entity other than an entity at least a majority of the issued and outstanding common stock of which is owned by Berkshire Hathaway, calculated on a diluted basis as described above;

provided that with respect to the foregoing subparagraphs (1) and (2), a Change of Control will not be deemed to have occurred unless and until a Rating Decline has occurred as well.

Table of Contents

‘‘Comparable Treasury Issue’’ means the United States Treasury security selected by an Independent Investment Banker as having a maturity comparable to the remaining term of securities of any series to be redeemed that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of such securities.

‘‘Comparable Treasury Price’’ means, with respect to any Redemption Date, (1) the average of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) on the third business day preceding such Redemption Date, as set forth in the daily statistical release (or any successor release) published by the Federal Reserve Bank of New York and designated ‘‘Composite 3:30 p.m. Quotations for U.S. Government Securities’’ or (2) if such release (or any successor release) is not published or does not contain such prices on such business day, the Reference Treasury Dealer Quotation for such Redemption Date.

‘‘Consolidated Net Tangible Assets’’ means, as of the date of any determination thereof, the total amount of all assets of MEHC determined on a consolidated basis in accordance with GAAP as of such date less the sum of (a) the consolidated current liabilities of MEHC determined in accordance with GAAP and (b) assets properly classified as Intangible Assets.

‘‘Currency Protection Agreement’’ means, with respect to any person, any foreign exchange contract, currency swap agreement or other similar agreement or arrangement intended to protect such person against fluctuations in currency values to or under which such person is a party or a beneficiary on the date of the indenture or becomes a party or a beneficiary thereafter.

‘‘Debt’’ means, with respect to any person, at any date of determination (without duplication):

(1) all Indebtedness for Borrowed Money of such person;

(2) all obligations of such person evidenced by bonds, bonds, securities or other similar instruments;

(3) all obligations of such person in respect of letters of credit, bankers’ acceptances, surety, bid, operating and performance bonds, performance guarantees or other similar instruments or obligations (or reimbursement obligations with respect thereto) (except, in each case, to the extent incurred in the ordinary course of business);

(4) all obligations of such person to pay the deferred purchase price of property or services, except Trade Payables;

(5) the Attributable Value of all obligations of such person as lessee under Capitalized Leases;

(6) all Debt of others secured by a Lien on any Property of such person, whether or not such Debt is assumed by such person, *provided* that, for purposes of determining the amount of any Debt of the type described in this clause, if recourse with respect to such Debt is limited to such Property, the amount of such Debt will be limited to the lesser of the fair market value of such Property or the amount of such Debt;

(7) all Debt of others Guaranteed by such person to the extent such Debt is Guaranteed by such person;

(8) all Redeemable Stock valued at the greater of its voluntary or involuntary liquidation preference plus accrued and unpaid dividends; and

(9) to the extent not otherwise included in this definition, all net obligations of such person under Currency Protection Agreements and Interest Rate Protection Agreements.

For purposes of determining any particular amount of Debt that is or would be outstanding, Guarantees of, or obligations with respect to letters of credit or similar instruments supporting (to the extent the foregoing constitutes Debt), Debt otherwise included in the determination of such particular amount will not be included. For purposes of determining compliance with the indenture, in the event that an item of Debt meets the criteria of more than one of the types of Debt described in the above clauses, MEHC, in its sole discretion, will classify such item of Debt and only be required to include the amount and type of such Debt in one of such clauses.

''Guarantee'' means any obligation, contingent or otherwise, of any person directly or indirectly guaranteeing any Debt of any other person and, without limiting the generality of the foregoing, any Debt obligation, direct or indirect, contingent or otherwise, of such person (1) to purchase or pay (or advance or supply funds for the purchase or payment of) such Debt of such other person (whether arising by virtue of partnership arrangements (other than solely by reason of being a general partner of a partnership), or by agreement to keep-well, to purchase assets, goods, securities or services or to take-or-pay, or to maintain financial statement conditions or otherwise) or (2) entered into for purposes of assuring in any other manner the obligee of such Debt of the payment thereof or to protect such obligee against loss in respect thereof (in whole or in part), *provided* that the term ''Guarantee'' will not include endorsements for collection or deposit in the ordinary course of business or the grant of a lien in connection with any Non-Recourse Debt. The term ''Guarantee'' used as a verb has a corresponding meaning.

''Independent Investment Banker'' means an independent investment banking institution of international standing appointed by MEHC.

''Intangible Assets'' means, as of the date of determination thereof, all assets of MEHC properly classified as intangible assets determined on a consolidated basis in accordance with GAAP.

''Interest Rate Protection Agreement'' means, with respect to any person, any interest rate protection agreement, interest rate future agreement, interest rate option agreement, interest rate swap agreement, interest rate cap agreement, interest rate collar agreement, interest rate hedge agreement or other similar agreement or arrangement intended to protect such person against fluctuations in interest rates to or under which such person or any of its Subsidiaries is a party or a beneficiary on the date of the indenture or becomes a party or a beneficiary thereafter.

''Joint Venture'' means a joint venture, partnership or other similar arrangement, whether in corporate, partnership or other legal form.

''Lien'' means, with respect to any Property, any mortgage, lien, pledge, charge, security interest or encumbrance of any kind in respect of such Property, but will not include any partnership, joint venture, shareholder, voting trust or similar governance agreement with respect to Capital Stock in a Subsidiary or Joint Venture. For purposes of the indenture, MEHC will be deemed to own subject to a Lien any Property that it has acquired or holds subject to the interest of a vendor or lessor under any conditional sale agreement, capital lease or other title retention agreement relating to such Property.

''Non-Recourse'' means any Debt or other obligation (or that portion of such Debt or other obligation) that is without recourse to MEHC or any property or assets directly owned by MEHC (other than a pledge of the equity interests in any Subsidiary of MEHC, to the extent recourse to MEHC under such pledge is limited to such equity interests).

''Property'' of any person means all types of real, personal, tangible or mixed property owned by such person whether or not included in the most recent consolidated balance sheet of such person under GAAP.

''Rating Agencies'' means (1) S&P and (2) Moody's or (3) if S&P or Moody's or both do not make a rating of the securities publicly available, a nationally recognized securities rating agency or agencies, as the case may be, selected by MEHC, which will be substituted for S&P or Moody's or both, as the case may be.

''Rating Decline'' means the occurrence of the following on, or within 90 days after, the earlier of (1) the occurrence of a Change of Control and (2) the earlier of (x) the date of public notice of the occurrence of a Change of Control or (y) the date of the public notice of the intention of MEHC to effect a Change of Control (the ''Rating Date''), which period will be extended so long as the rating of the 2006 bonds is under publicly announced consideration for possible downgrading by any of the Rating Agencies: the rating of such securities by both such Rating Agencies is reduced below BBB+, in the case of S&P, and Baa1, in the case of Moody's.

''Redeemable Stock'' means any class or series of Capital Stock of any person that by its terms or otherwise is (1) required to be redeemed prior to the stated maturity of any series of the securities,

(2) redeemable at the option of the holder of such class or series of Capital Stock at any time prior to the stated maturity of any series of the securities or (3) convertible into or exchangeable for Capital Stock referred to in clause (1) or (2) above or Debt having a scheduled maturity prior to the stated maturity of any series of the securities, *provided* that any Capital Stock that would not constitute Redeemable Stock but for provisions thereof giving holders thereof the right to require MEHC to purchase or redeem such Capital Stock upon the occurrence of a ''change of control'' occurring prior to the stated maturity of any series of the securities will not constitute Redeemable Stock if the ''change of control'' provisions applicable to such Capital Stock are no more favorable to the holders of such Capital Stock than the provisions contained in the covenants described under ''Purchase of Securities Upon a Change of Control'' above.

''Redemption Date'' means any date on which MEHC redeems all or any portion of the securities in accordance with the terms of the indenture.

''Reference Treasury Dealer'' means a primary U.S. government securities dealer in New York City appointed by MEHC.

''Reference Treasury Dealer Quotation'' means, with respect to the Reference Treasury Dealer and any Redemption Date, the average, as determined by MEHC, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount and quoted in writing to MEHC by such Reference Treasury Dealer at 5:00 p.m. on the third business day preceding such Redemption Date).

''Significant Subsidiary'' means a ''significant subsidiary'' as defined in Rule 1-02(w) of Regulation S-X under the Securities Act and the Exchange Act, substituting 20 percent for 10 percent each place it appears therein. Unless the context otherwise clearly requires, any reference to a ''Significant Subsidiary'' is a reference to a Significant Subsidiary of MEHC.

‘‘Subsidiary’’ means, with respect to any person, including, without limitation, MEHC and its Subsidiaries, any corporation or other entity of which such person owns, directly or indirectly, a majority of the Capital Stock or other ownership interests and has ordinary voting power to elect a majority of the board of directors or other persons performing similar functions.

‘‘Trade Payables’’ means, with respect to any person, any accounts payable or any other indebtedness or monetary obligation to trade creditors incurred, created, assumed or Guaranteed by such person or any of its Subsidiaries or Joint Ventures arising in the ordinary course of business.

‘‘Treasury Yield’’ means, with respect to any Redemption Date, the rate per annum equal to the semiannual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for such Redemption Date.

‘‘U.S. Government Obligations’’ means any security that is (1) a direct obligation of the United States for the payment of which its full faith and credit is pledged or (2) an obligation of a person controlled or supervised by and acting as an agency or instrumentality of the United States, the payment of which is unconditionally guaranteed as a full faith and credit obligation by the United States, that, in the case of clause (1) or (2) is not callable or redeemable at the option of the issuer thereof, and will also include any depository receipt issued by a bank or trust company as custodian with respect to any such U.S. Government Obligations or a specific payment of interest on or principal of any such U.S. Government Obligation held by such custodian for the account of the holder of a depository receipt, *provided* that (except as required by law) such custodian is not authorized to make any deduction from the amount payable to the holder of such depository receipt from any amount received by the custodian in respect of the U.S. Government Obligation or the specific payment of interest on or principal of the U.S. Government Obligation evidenced by such depository receipt.

‘‘Voting Stock’’ means, with respect to any person, Capital Stock of any class or kind ordinarily having the power to vote for the election of directors (or persons fulfilling similar responsibilities) of such person.

Table of Contents

Global Bonds; Book-Entry System

The initial 2006 bonds were and the exchange 2006 bonds will be, issued under a book-entry system in the form of one or more global bonds (each, a ‘‘Global Bond’’). Each Global Bond with respect to the initial 2006 bonds was, and each Global Bond with respect to the exchange 2006 bonds will be, deposited with, or on behalf of, a depositary, which will be The Depository Trust Company, New York, New York (the ‘‘Depositary’’). The Global Bonds with respect to the initial 2006 bonds were, and the Global Bonds with respect to the exchange 2006 bonds will be, registered in the name of the Depositary or its nominee.

The initial 2006 bonds were not issued in certificated form and, except under the limited circumstances described below, owners of beneficial interests in the Global Bonds are not entitled to physical delivery of the bonds in certificated form. The Global Bonds may not be transferred except as a whole by the Depositary to a nominee of the Depositary or by a nominee of the Depositary to the Depositary or another nominee of the Depositary or by the Depositary or any nominee to a successor of the Depositary or a nominee of such successor.

The Depositary is a limited-purpose trust company organized under the New York Banking Law, a ‘‘banking organization’’ within the meaning of the New York Banking Law, a member of the Federal Reserve System, a ‘‘clearing corporation’’ within the meaning of the New York Uniform Commercial Code, and a ‘‘clearing agency’’ registered pursuant to the provisions of Section 17A of the Exchange Act. The Depositary holds securities that its participants (‘‘Direct Participants’’) deposit with the Depositary. The Depositary also facilitates the post-trade settlement among Direct Participants of securities transactions, such as transfers and pledges, in deposited securities through electronic computerized book-entry changes in Direct Participants’ accounts, thereby eliminating the need for physical movement of securities certificates. Direct Participants include securities brokers and dealers, banks, trust companies, clearing corporations and certain other organizations, including Euroclear Bank S.A./N.V. as operator of the Euroclear System (‘‘Euroclear’’) and Clearstream Banking, société anonyme (‘‘Clearstream’’). The Depositary is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation (‘‘DTCC’’). DTCC, in turn, is owned by a number of Direct Participants and Members of the National Securities Clearing Corporation, Government Securities Clearing Corporation, MBS Clearing Corporation and Emerging Markets Clearing Corporation, also subsidiaries of DTCC, as well as by the New York Stock Exchange, Inc., the American Stock Exchange LLC and the National Association of Securities Dealers, Inc. Access to the Depositary system is also available to others such as securities brokers and dealers, banks and trust companies that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly (‘‘Indirect Participants’’). The rules applicable to the Depositary and its Direct and Indirect Participants are on file with the SEC.

Purchases of the securities under the Depositary system must be made by or through Direct Participants, which will receive a credit for the securities on the Depositary’s records. The ownership interest of each actual purchaser of each security (‘‘Beneficial Owner’’) is in turn to be recorded on the Direct and Indirect Participants’ records. Beneficial Owners will not receive written confirmation from the Depositary of their purchase, but Beneficial Owners are expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the securities are to be accomplished by entries made on the books of Direct and Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in securities, except in the event that use of the book-entry system for the securities is discontinued.

To facilitate subsequent transfers, all bonds deposited by Direct Participants with the Depositary are registered in the name of the Depositary’s partnership nominee, Cede & Co., or such other name as may be requested by an authorized representative of the Depositary. The deposit of bonds with the Depositary and their registration in the name of Cede & Co. or such other nominee effect no change in beneficial ownership. The

Depositary has no knowledge of the actual Beneficial Owners of the bonds; the Depositary's records reflect only the identity of the Direct Participants to whose accounts

such bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by the Depositary to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners are governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time.

Neither the Depositary nor Cede & Co. (nor any other nominee of the Depositary) will consent or vote with respect to the bonds unless authorized by a Direct Participant in accordance with the Depositary's procedures. Under its usual procedures, the Depositary mails an Omnibus Proxy to MEHC as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts the securities are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Principal (and premium, if any) and interest payments on the bonds and any redemption payments are made to Cede & Co. (or such other nominee as may be requested by an authorized representative of the Depositary). The Depositary's practice is to credit Direct Participants' accounts upon the Depositary's receipt of funds and corresponding detail information from MEHC or the trustee on the payable date in accordance with their respective holdings shown on the Depositary's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in ''street name,'' and will be the responsibility of such Participant and not of the Depositary, the trustee or MEHC, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal (and premium, if any), interest and any redemption proceeds to Cede & Co. (or such other nominee as may be requested by an authorized representative of the Depositary) is the responsibility of MEHC, disbursements of such payments to Direct Participants shall be the responsibility of the Depositary, and disbursement of such payments to the Beneficial Owners shall be the responsibility of Direct and Indirect Participants.

The Depositary may discontinue providing its services as securities depositary with respect to the bonds at any time by giving reasonable notice to MEHC or the trustee. Under such circumstances, in the event that a successor securities depositary is not obtained, certificated bonds are required to be printed and delivered. MEHC may decide to discontinue use of the system of book-entry transfers through the Depositary (or a successor securities depositary). In that event, certificated bonds will be printed and delivered.

The information in this section concerning the Depositary and the Depositary's book-entry system has been obtained from sources that MEHC believes to be reliable but has not been independently verified by MEHC, the initial purchasers or the trustee.

Prior to the expiration of the ''40-day distribution compliance period'' (within the meaning of Rule 903 of Regulation S), beneficial interests in any Global Bond for bonds sold outside the United States in reliance on Regulation S under the Securities Act may only be held through Euroclear or Clearstream, unless delivery is made pursuant to an exemption from registration under the Securities Act in accordance with the certification requirements of the indenture.

A Global Bond of any series may not be transferred except as a whole by the Depositary to a nominee or successor of the Depositary or by a nominee of the Depositary to another nominee of the Depositary. A Global Bond representing bonds is exchangeable, in whole but not in part, for bonds in definitive form of like tenor and terms if (1) the Depositary notifies MEHC that it is unwilling or unable to continue as depositary for such Global Bond or if at any time the Depositary is no longer eligible to be or in good standing as a ''clearing agency'' registered under the Exchange Act, and in either case, a successor depositary is not appointed by MEHC within 120 days of receipt by MEHC of such notice or of MEHC becoming aware of such ineligibility, (2) while such Global Bond is subject to the transfer restrictions described under ''Transfer Restrictions,'' the book-entry interests in such Global Bond cease to be eligible for Depositary services because such 2006 bonds are neither (a) rated in one of the top four categories by a nationally recognized statistical rating organization nor

(b) included within a Self-Regulatory Organization system approved by the SEC for the reporting of quotation and trade information of securities eligible for transfer pursuant to Rule 144A under the Securities Act, or (3) MEHC in its sole discretion at any time determines not to have such bonds represented by a Global Bond and notifies the trustee thereof. A Global Bond exchangeable pursuant to the preceding sentence shall be exchangeable for bonds registered in such names and in such authorized denominations as the Depositary shall direct.

CERTAIN UNITED STATES FEDERAL INCOME TAX CONSIDERATIONS

The exchange of initial 2006 bonds for exchange 2006 bonds pursuant to the exchange offer will not constitute a taxable event for U.S. federal income tax purposes.

The exchange 2006 bonds received by a holder of initial 2006 bonds should be treated as a continuation of such holder's investment in the initial 2006 bonds; thus there should be no material U.S. federal income tax consequences to holders exchanging initial 2006 bonds for exchange 2006 bonds. As a result:

- a holder of initial 2006 bonds will not recognize taxable gain or loss as a result of the exchange of initial 2006 bonds for exchange 2006 bonds pursuant to the exchange offer;
- the holding period of the exchange 2006 bonds will include the holding period of the initial 2006 bonds surrendered in exchange therefor; and
- a holder's adjusted tax basis in the exchange 2006 bonds will be the same as such holder's adjusted tax basis in the initial 2006 bonds surrendered in exchange therefor.

Table of Contents

PLAN OF DISTRIBUTION

Based on existing interpretations of the Securities Act by the staff of the SEC set forth in several no-action letters to third parties, and subject to the immediately following sentence, we believe that the exchange 2006 bonds that will be issued pursuant to the exchange offer may be offered for resale, resold and otherwise transferred by the holders thereof without further compliance with the registration and prospectus delivery provisions of the Securities Act. However, any purchaser of bonds who is an ''affiliate'' (within the meaning of the Securities Act) of ours or who intends to participate in the exchange offer for the purpose of distributing the exchange 2006 bonds or a broker-dealer (within the meaning of the Securities Act) that acquired initial 2006 bonds in a transaction other than as part of its market-making or other trading activities and who has arranged or has an understanding with any person to participate in the distribution of the exchange 2006 bonds: (1) will not be able to rely on the interpretations by the staff of the SEC set forth in the above-mentioned no-action letters; (2) will not be able to tender its initial 2006 bonds in the exchange offer; and (3) must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any sale or transfer of the bonds unless such sale or transfer is made pursuant to an exemption from such requirements.

Each broker-dealer that receives exchange 2006 bonds for its own account pursuant to the exchange offer must acknowledge that it will deliver a prospectus in connection with any resale of such exchange 2006 bonds. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of exchange 2006 bonds received in exchange for initial 2006 bonds where such initial 2006 bonds were acquired as a result of market-marketing activities or other trading activities. We have agreed that, for a period of 120 days after the expiration date, we will make this prospectus, as amended or supplemented, available to any broker-dealer for use in connection with any such resale. In addition, until October 11, 2006, all dealers effecting transactions in the exchange 2006 bonds may be required to deliver a prospectus.

We will not receive any proceeds from any such sale of exchange 2006 bonds by broker-dealers. Exchange 2006 bonds received by broker-dealers for their own account pursuant to the exchange offer may be sold from time to time in one or more transactions in the over-the-counter market, in negotiated transactions, through the writing of options on the exchange 2006 bonds or a combination of such methods of resale, at market prices prevailing at the time of resale, at prices related to such prevailing market prices or at negotiated prices. Any such resale may be made directly to purchasers or to or through brokers or dealers who may receive compensation in the form of commissions or concessions from any such broker/dealer and/or the purchasers of any such exchange 2006 bonds. Any broker-dealer that resells exchange 2006 bonds that were received by it for its own account pursuant to the exchange offer and any broker or dealer that participates in a distribution of such exchange 2006 bonds may be deemed to be an ''underwriter'' within the meaning of the Securities Act and any profit on any such resale of exchange 2006 bonds and any commissions or concessions received by any such persons may be deemed to be underwriting compensation under the Securities Act. The letters of transmittal states that by acknowledging that it will deliver and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an ''underwriter'' within the meaning of the Securities Act.

For a period of 120 days after the expiration date we will promptly send additional copies of this prospectus and any amendment or supplement to this prospectus to any broker-dealer that requests such documents in the letter of transmittal. We have agreed to pay all expenses incident to the exchange offer (including the expenses of one counsel for the holders of the bonds other than commissions or concessions of any brokers or dealers and will indemnify the holders of the bonds (including any broker-dealers) against certain liabilities, including liabilities under the Securities Act.

Table of Contents

NOTICE TO CANADIAN RESIDENTS

Any resale of the bonds in Canada must be made under applicable securities laws which will vary depending on the relevant jurisdiction, and which may require resales to be made under available statutory exemptions or under a discretionary exemption granted by the applicable Canadian securities regulatory authority. Note holders resident in Canada are advised to seek legal advice prior to any resale of the bonds.

LEGAL MATTERS

Certain legal matters with respect to the exchange 2006 bonds will be passed upon for us by Willkie Farr & Gallagher LLP, New York, New York.

EXPERTS

The consolidated financial statements and the related financial statement schedules included elsewhere in this prospectus of MidAmerican Energy Holdings Company and its subsidiaries, as of December 31, 2005 and 2004 and for each of the three years in the period ended December 31, 2005, included in this prospectus have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report appearing herein, and is included in reliance upon the report of such firm given upon their authority as experts in accounting and auditing.

With respect to the unaudited interim financial information of MidAmerican Energy Holdings Company for the three-month and six-month periods ended June 30, 2006 and 2005, included in this prospectus, Deloitte & Touche LLP, an independent registered public accounting firm, have applied limited procedures in accordance with the standards of the Public Company Accounting Oversight Board (United States) for a review of such information. However, as stated in their report appearing herein, they did not audit and they do not express an opinion on that interim financial information. Accordingly, the degree of reliance on their report on such information should be restricted in light of the limited nature of the review procedures applied. Deloitte & Touche LLP are not subject to the liability provisions of Section 11 of the Securities Act of 1933 for their report on the unaudited interim financial information because this report is not a ‘‘report’’ or a ‘‘part’’ of the registration statement prepared or certified by an accountant within the meaning of Sections 7 and 11 of the Act.

With respect to the unaudited interim financial information of PacifiCorp for the three-month period ended June 30, 2006, included in this prospectus, Deloitte & Touche LLP, an independent registered public accounting firm, have applied limited procedures in accordance with the standards of the Public Company Accounting Oversight Board (United States) for a review of such information. However, as stated in their report appearing herein, they did not audit and they do not express an opinion on that interim financial information. Accordingly, the degree of reliance on their report on such information should be restricted in light of the limited nature of the review procedures applied. Deloitte & Touche LLP are not subject to the liability provisions of Section 11 of the Securities Act of 1933 for their report on the unaudited interim financial information because this report is not a ‘‘report’’ or a ‘‘part’’ of the registration statement prepared or certified by an accountant within the meaning of Sections 7 and 11 of the Act.

The consolidated financial statements of PacifiCorp and its subsidiaries as of March 31, 2006 and 2005 and for each of the three years in the period ended March 31, 2006, included in this prospectus, have been so included in reliance on the report of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in accounting and auditing.

WHERE YOU CAN FIND MORE INFORMATION

We file reports and information statements and other information with the SEC. Such reports, proxy and information statements and other information filed by us with the SEC can be inspected and copied at the Public Reference Section of the SEC at 100 F Street, NE, Room 1580, Washington, D.C. 20549, and at the regional offices of the SEC located at Woolworth Building, 233 Broadway, New

---

York, New York 10279 and 500 West Madison Street, Suite 1400, Chicago, Illinois 60661. Copies of such material can be obtained from the Public Reference Section of the SEC at 100 F Street, NE, Room 1580, Washington, D.C. 20549 at prescribed rates. The SEC maintains a Web site that contains reports, proxy and information statements and other materials that are filed through the SEC’s Electronic Data Gathering, Analysis, and Retrieval (EDGAR) system. This Web site can be accessed at *http://www.sec.gov*.

We make available free of charge through our internet website at *http.//www.midamerican.com* our annual report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as soon as reasonably practicable after we electronically file with, or furnish it to, the SEC. Any information available on or through our website is not part of this prospectus and our web address is included as an inactive textual reference only.

FINANCIAL STATEMENTS

Index to Financial Statements

MidAmerican Energy Holdings Company:

Unaudited Interim Consolidated Financial Statements

Audited Consolidated Financial Statements

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have reviewed the accompanying consolidated balance sheet of MidAmerican Energy Holdings Company and subsidiaries (the ''Company'') as of June 30, 2006, and the related consolidated statements of operations for the three-month and six-month periods ended June 30, 2006 and 2005, and of stockholders' equity and cash flows for the six-month periods ended June 30, 2006 and 2005. These interim financial statements are the responsibility of the Company's management.

We conducted our reviews in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our reviews, we are not aware of any material modifications that should be made to such consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of MidAmerican Energy Holdings Company and subsidiaries as of December 31, 2005, and the related consolidated statements of operations, stockholders' equity, and cash flows for the year then ended (not presented herein); and in our report dated March 3, 2006, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2005 is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Deloitte & Touche LLP
Des Moines, Iowa
August 4, 2006

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

	As of	
	June 30, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 393.9	$ 357.9

Short-term investments	19.1	38.4
Restricted cash and short-term investments	97.7	102.9
Accounts receivable, net	1,049.7	802.6
Amounts held in trust	122.7	108.5
Inventories	339.0	128.2
Derivative contracts	229.2	54.0
Deferred income taxes	137.9	177.7
Other current assets	290.9	140.1
Total current assets	2,680.1	1,910.3
Properties, plants and equipment, net	22,647.0	11,915.4
Goodwill	5,275.4	4,156.2
Regulatory assets	1,730.0	441.1
Other investments	961.0	798.7
Derivative contracts	328.6	6.1
Deferred charges and other assets	1,375.8	1,142.9
Total assets	$34,997.9	$ 20,370.7
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 851.1	$ 523.6
Accrued interest	276.2	198.3
Accrued property and other taxes	308.1	189.1
Amounts held in trust	122.7	108.5
Derivative contracts	138.3	61.7
Other liabilities	552.1	389.3
Short-term debt	317.5	70.1
Current portion of long-term debt	502.3	313.7
Current portion of parent company subordinated debt	234.0	234.0
Total current liabilities	3,302.3	2,088.3
Other long-term accrued liabilities	899.0	766.9
Regulatory liabilities	1,608.4	773.9
Pension and postretirement obligations	1,444.7	633.3
Derivative contracts	579.9	106.8
Parent company senior debt	4,477.1	2,776.2
Parent company subordinated debt	1,288.3	1,354.1
Subsidiary and project debt	10,540.8	6,836.6
Deferred income taxes	3,309.2	1,539.6
Total liabilities	27,449.7	16,875.7
Minority interest	83.6	21.4
Preferred securities of subsidiaries	129.1	88.4
Commitments and contingencies (Note 9)		
Stockholders' equity:		
Zero-coupon convertible preferred stock — no shares authorized, issued or outstanding at June 30, 2006; 50.0 shares authorized, no par value, 41.3 shares issued and outstanding at December 31, 2005	—	—
Common stock — 115.0 shares authorized, no par value, 74.2 shares issued and outstanding at June 30, 2006; 60.0 shares authorized, no par value, 9.3 shares issued and outstanding at December 31, 2005	—	—
Additional paid-in capital	5,393.6	1,963.3
Retained earnings	2,083.6	1,719.5
Accumulated other comprehensive loss, net	(141.7)	(297.6)
Total stockholders' equity	7,335.5	3,385.2
Total liabilities and stockholders' equity	$34,997.9	$ 20,370.7

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

Table of Contents

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

	Three-Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2006	2005	2006	2005
Operating revenue	$2,617.5	$1,604.4	$4,672.1	$3,408.6
Costs and expenses:				
Cost of sales	1,142.9	733.8	2,096.9	1,546.5
Operating expense	698.7	398.6	1,148.8	806.0
Depreciation and amortization	304.0	137.4	492.0	297.0
Total costs and expenses	2,145.6	1,269.8	3,737.7	2,649.5
Operating income	471.9	334.6	934.4	759.1
Other income (expense):				
Interest expense	(308.1)	(224.1)	(529.8)	(455.7)
Capitalized interest	10.3	4.6	14.9	8.2
Interest and dividend income	18.2	15.0	33.6	23.4
Other income	51.7	18.0	174.6	39.0
Other expense	(7.3)	(1.5)	(8.6)	(4.8)
Total other income (expense)	(235.2)	(188.0)	(315.3)	(389.9)
Income from continuing operations before income tax expense, minority interest and preferred dividends of subsidiaries and equity income	236.7	146.6	619.1	369.2
Income tax expense	81.7	57.6	212.9	131.6
Minority interest and preferred dividends of subsidiaries	9.9	3.8	13.9	6.6
Income from continuing operations before equity income	145.1	85.2	392.3	231.0
Equity income	7.9	13.2	9.7	18.1
Income from continuing operations	153.0	98.4	402.0	249.1
Income from discontinued operations, net of income tax	—	1.3	—	3.0
Net income available to common and preferred stockholders	$ 153.0	$ 99.7	$ 402.0	$ 252.1

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

Table of Contents

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (Unaudited)
FOR THE SIX-MONTH PERIODS ENDED JUNE 30, 2006 AND 2005
(Amounts in millions)

	Outstanding Common Shares	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total
Balance, January 1, 2005	9.0	$ —	$ 1,950.7	$1,156.8	$ (136.3)	$ 2,971.2
Net income	—	—	—	252.1	—	252.1
Other comprehensive income	—	—	—	—	(147.4)	(147.4)
Balance, June 30, 2005	9.0	$ —	$ 1,950.7	$1,408.9	$ (283.7)	$ 3,075.9
Balance, January 1, 2006	9.3	$ —	$ 1,963.3	$1,719.5	$ (297.6)	$ 3,385.2
Net income	—	—	—	402.0	—	402.0
Other comprehensive income	—	—	—	—	155.9	155.9
Preferred stock conversion to common stock	41.3	—	—	—	—	—
Exercise of common stock options	0.5	—	13.1	—	—	13.1
Tax benefit from exercise of common stock options	—	—	19.8	—	—	19.8
Common stock issuances	35.2	—	5,109.5	—	—	5,109.5
Common stock purchases	(12.1)	—	(1,712.1)	(37.9)	—	(1,750.0)
Balance, June 30, 2006	74.2	$ —	$ 5,393.6	$2,083.6	$ (141.7)	$ 7,335.5

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

Table of Contents

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

	Six-Month Periods Ended June 30, 2006	2005
Cash flows from operating activities:		
Income from continuing operations	$ 402.0	$ 249.1
Adjustments to reconcile income from continuing operations to cash flows from continuing operations:		
Distributions less income on equity investments	2.0	(8.9)
Gain on other items, net	(129.8)	(36.4)
Depreciation and amortization	492.0	297.0
Amortization of regulatory assets and liabilities	26.0	24.8
Amortization of deferred financing costs	8.2	11.8
Provision for deferred income taxes	171.5	107.5
Other	(11.9)	28.2
Changes in other items, net of effects from acquisitions:		
Accounts receivable and other current assets	284.2	157.5
Accounts payable and other accrued liabilities	(285.8)	35.7
Deferred income	(5.5)	(3.3)
Net cash flows from continuing operations	952.9	863.0
Net cash flows from discontinued operations	—	(1.9)
Net cash flows from operating activities	952.9	861.1
Cash flows from investing activities:		
PacifiCorp acquisition, net of cash acquired	(4,932.0)	—
Other acquisitions, net of cash acquired	(68.4)	(1.0)
Capital expenditures relating to operating projects	(698.2)	(338.4)
Construction and other development costs	(219.3)	(170.4)
Purchases of available-for-sale securities	(866.9)	(1,729.0)
Proceeds from sale of available-for-sale securities	974.6	1,739.0
Purchase of other investments	—	(556.6)
Proceeds from sale of assets	14.0	56.0
Other	5.9	22.1
Net cash flows from continuing operations	(5,790.3)	(978.3)
Net cash flows from discontinued operations	—	5.4
Net cash flows from investing activities	(5,790.3)	(972.9)
Cash flows from financing activities:		
Proceeds from the issuances of common stock	5,122.6	—
Purchases of common stock	(1,750.0)	—
Proceeds from parent company senior debt	1,699.3	—

Proceeds from subsidiary and project debt	11.8	752.1
Repayments of parent company senior and subordinated debt	(67.0)	(21.5)
Repayments of subsidiary and project debt	(245.3)	(606.5)
Net proceeds from subsidiary short-term debt	114.1	1.4
Net repayments of parent company revolving credit facility	(51.0)	—
Net proceeds from settlement of treasury rate lock agreements	53.0	—
Other	(15.7)	(7.6)
Net cash flows from financing activities	4,871.8	117.9
Effect of exchange rate changes	1.6	(15.2)
Net change in cash and cash equivalents	36.0	(9.1)
Cash and cash equivalents at beginning of period	357.9	837.3
Cash and cash equivalents at end of period	$ 393.9	$ 828.2

The accompanying notes are an integral part of these financial statements

Table of Contents

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. General

The accompanying unaudited consolidated financial statements have been prepared in accordance with generally accepted accounting principles for interim financial information and the instructions for Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by generally accepted accounting principles for annual financial statements. In the opinion of the management of MidAmerican Energy Holdings Company (‘‘MEHC’’) and its subsidiaries (collectively, the ‘‘Company’’), the unaudited consolidated financial statements contain all adjustments, including normal recurring items, considered necessary for a fair presentation of the financial position as of June 30, 2006 and the results of operations for the three-month and six-month periods ended June 30, 2006 and 2005, and the changes in stockholders’ equity and the cash flows for the six-month periods ended June 30, 2006 and 2005. The results of operations for the three-month and six-month periods ended June 30, 2006 are not necessarily indicative of the results to be expected for the full year.

Preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenue and expenses during the period. Management believes the most complex and sensitive judgments, because of their significance to the consolidated financial statements, result primarily from the need to make estimates about the effects of matters that are inherently uncertain. Actual results could differ materially from management’s estimates. Management’s Discussion and Analysis and Note 2 to the consolidated financial statements included in the Company’s Annual Report on Form 10-K for the year ended December 31, 2005, describe the most significant accounting estimates and policies used in preparation of the consolidated financial statements. There have been no significant changes in the Company’s assumptions regarding critical accounting estimates during the first six months of 2006, except as they relate to the PacifiCorp acquisition and PacifiCorp’s derivative instruments (see Note 3).

The unaudited consolidated financial statements include the accounts of MEHC and its wholly-owned subsidiaries, except for certain trusts formed to hold trust preferred securities which were deconsolidated under Financial Accounting Standards Board Interpretation No. 46R, ‘‘Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51.’’ Subsidiaries which are less than 100% owned but greater than 50% owned are consolidated with a minority interest. Subsidiaries that are 50% owned or less, but where the Company has the ability to exercise significant influence, are accounted for under the equity method of accounting. All inter-enterprise transactions and accounts have been eliminated. The results of operations of the Company include the Company’s proportionate share of results of operations of entities acquired from the date of each acquisition for purchase business combinations.

Berkshire Hathaway Inc. (‘‘Berkshire Hathaway’’) currently owns 88.2% (86.6% on a diluted basis) of the outstanding common stock of MEHC. 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, CalEnergy Generation-Domestic and HomeServices of America, Inc. (‘‘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 natural gas pipeline companies in the United

Table of Contents

States, two electricity distribution companies in Great Britain, a diversified portfolio of domestic and international independent power projects and the second largest residential real estate brokerage firm in the United States.

Certain amounts in the prior period consolidated financial statements and supporting note disclosures have been reclassified to conform to the current period presentation. Such reclassifications did not impact previously reported net income or retained earnings.

As of December 31, 2005, the Company reclassified $1.6 billion of accumulated depreciation related to the acquisitions of Northern Natural Gas and Kern River from property to accumulated depreciation to conform to its current period presentation.

2. New Accounting Pronouncements

In July 2006, the Financial Accounting Standards Board (''FASB'') issued FASB Interpretation No. 48, ''Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109'' (''FIN 48''). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in accordance with Statement of Financial Accounting Standards (''SFAS'') No. 109, ''Accounting for Income Taxes'' (''SFAS 109''), and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a return. Guidance is also provided on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006. The Company is currently evaluating the impact of adopting FIN 48 on its consolidated financial position and results of operations.

In December 2004, the FASB issued SFAS No. 123R, ''Share-Based Payment'' (''SFAS 123R''), which replaces SFAS No. 123, ''Accounting for Stock-Based Compensation,'' and supersedes Accounting Principles Board Opinion No. 25, ''Accounting for Stock Issued to Employees.'' SFAS 123R establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services, primarily focusing on the accounting for transactions in which an entity obtains employee services in share-based payment transactions. SFAS 123R requires entities to measure compensation costs for all share-based payments, including stock options, at fair value and expense such payments over the service period. As of January 1, 2006, the Company adopted SFAS 123R. Adoption of SFAS 123R did not affect the Company's financial position, results of operations or cash flows as all of the Company's outstanding stock options were fully vested on January 1, 2006. Modifications to outstanding stock options after January 1, 2006 may result in additional compensation expense pursuant to the provisions of SFAS 123R.

3. PacifiCorp Acquisition

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 $5,109.5 million, which was funded through the issuance of common stock (see Note 4). MEHC also incurred $10.2 million of direct transaction costs associated with the acquisition, which consisted principally of investment banker commissions and outside legal and accounting fees and expenses, resulting in a total purchase price of $5,119.7 million. As a result of the acquisition, MEHC controls the significant majority of PacifiCorp's voting securities, which include both common and preferred stock. The results of PacifiCorp's operations are included in the Company's results beginning March 21, 2006.

PacifiCorp is a regulated electric utility serving approximately 1.6 million residential, commercial and industrial customers in service territories aggregating approximately 136,000 square miles in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. The regulatory commissions in each state approve rates for retail electric sales within their respective states. PacifiCorp also sells electricity on the wholesale market to public and private utilities, energy marketing companies and to incorporated municipalities. Wholesale activities are regulated by the Federal Energy Regulatory Commission (''FERC''). As of June 30, 2006, PacifiCorp owns, or has interests in, 69 thermal, hydroelectric and wind generating plants with an aggregate facility net owned capacity of 8,469.9 megawatts (''MW'').

Allocation of Purchase Price

SFAS No. 141, ''Business Combinations,'' requires that the total purchase price be allocated to PacifiCorp's net tangible and identified intangible assets acquired and liabilities assumed based on their estimated fair values as of the acquisition date. PacifiCorp's operations are regulated, which provide revenue derived from cost, and are accounted for pursuant to SFAS No. 71, ''Accounting for the Effects of Certain Types of Regulation'' (''SFAS 71''). PacifiCorp has demonstrated a past history of recovering its costs incurred through its rate making process. Given the size and timing of the acquisition, the fair values set forth below are preliminary and are subject to adjustment as additional information is obtained. When finalized, adjustments to goodwill may result. The following table summarizes the preliminary estimated fair values of the assets acquired and liabilities assumed as of the acquisition date (in millions).

	Preliminary Fair Value
Current assets, including cash and cash equivalents of $182.5	$ 1,115.3
Properties, plants and equipment, net	10,050.9
Goodwill	1,074.0
Regulatory assets	1,398.2
Other non-current assets	660.9
Current liabilities, including short-term debt of $184.4 and current portion of long-term debt of $220.6	(1,253.9)
Regulatory liabilities	(818.2)
Pension and postretirement obligations	(827.8)
Subsidiary and project debt, less current portion	(3,762.3)
Deferred income taxes	(1,680.9)
Other non-current liabilities	(836.5)
Net assets acquired	$ 5,119.7

The Company has not identified any material pre-acquisition contingencies where the related asset, liability or impairment is probable and the amount of the asset, liability or impairment can be reasonably estimated. Prior to the end of the purchase price allocation period, if information becomes available that a pre-acquisition related loss had been incurred and the amounts can be reasonably estimated, such items will be included in the purchase price allocation.

Certain transition activities will occur as PacifiCorp is integrated into the Company. Costs, consisting primarily of employee termination activities, will be incurred associated with such transition activities. The Company is in the process of finalizing these plans and expects to execute them over the next several months. In accordance with Emerging Issues Task Force Issue No. 95-3, ''Recognition of Liabilities in Connection with a Purchase Business Combination'' (''EITF 95-3''), the finalization of certain integration plans will result in adjustments to the purchase price allocation for the acquired assets and assumed liabilities of PacifiCorp. Severance costs accrued pursuant to EITF 95-3 during the period from acquisition to June 30, 2006 totaled $17.9 million. Accrued severance costs were $16.2 million at June 30, 2006. Transition costs that do not meet the criteria in EITF 95-3 are expensed in the period incurred.

Properties, Plants and Equipment, Net

The fair values of properties, plants and equipment, net as of the acquisition date are as follows (in millions):

	Ranges of Estimated Useful Life	Preliminary Fair Value
Utility generation and distribution system, net	5-85 years	$ 9,314.0
Other assets, net	5-30 years	8.9
Construction in progress(1)		728.0
Total properties, plants and equipment, net		$10,050.9

(1) Includes $173.5 million related to the Currant Creek Power Plant, a 523 MW combined cycle plant in Utah that went into service on March 22, 2006.

Goodwill

The excess of the purchase price paid over the estimated fair values of the identifiable assets acquired and liabilities assumed totaled $1,074.0 million and was allocated as goodwill to the PacifiCorp reportable segment. In accordance with SFAS No. 142, ''Goodwill and Other Intangible Assets,'' goodwill is not amortized, but rather is reviewed annually for impairment or more frequently if indicators of impairment exist. In accordance with SFAS 109, a deferred tax liability was not recorded on the goodwill since it is not tax deductible.

The recognition of goodwill from the acquisition of PacifiCorp resulted from various attributes of PacifiCorp's operations and business in general. There is no assurance that these attributes will continue to exist to the same degree as believed at the time of the acquisition. These attributes include, but are not limited to:

- Ability to improve operational results through the prudent deployment of capital;
- Operations in six states providing regulatory and geographic diversity;
- Ability to improve regulatory relationships and develop customer solutions;
- Low-cost competitive position;
- Generation and fuel diversification, including:
  - The operation of coal generation;
  - The operation of several coal mines contributing to low-cost supply and supply certainty;
  - Access to multiple gas suppliers; and
  - Low-cost hydroelectric generation;
- Strong customer service reputation; and
- Significant customer and load growth opportunities.

Regulatory Assets and Liabilities

The fair values of regulatory assets as of the acquisition date are as follows (in millions):

	Preliminary Fair Value
Pension and postretirement benefits	$ 684.5
Deferred income taxes	480.3
Derivative contracts(1)	94.7
Other	138.7
Total regulatory assets	$1,398.2

(1) Represents net unrealized losses related to derivative contracts included in rates as of the acquisition date.

As of the acquisition date, PacifiCorp had $1,372.1 million of regulatory assets not included in rate base and, therefore, not earning a return. PacifiCorp evaluates the recovery of all regulatory assets periodically and as events occur. The evaluation includes the probability of recovery as well as changes in the regulatory environment. Regulatory and/or legislative action in Utah, Oregon, Wyoming, Washington, Idaho and California may require PacifiCorp to record regulatory asset write-offs and charges for impairment of long-lived assets in future periods.

The fair values of regulatory liabilities as of the acquisition date are as follows (in millions):

	Preliminary Fair Value
Asset retirement removal costs	$ 713.3
Deferred income taxes	43.7
Other	61.2
Total regulatory liabilities	$ 818.2

Derivative Instruments

In accordance with SFAS No. 133, ''Accounting for Derivative Instruments and Hedging Activities'' (''SFAS 133''), as amended, PacifiCorp records derivative instruments as assets or liabilities measured at estimated fair value, unless they qualify for the exemptions afforded by SFAS 133. PacifiCorp uses derivative instruments (primarily forward purchases and sales) to manage the commodity price risk inherent in its fuel and electricity obligations, as well as to optimize the value of power generation assets and related contracts. Changes in the fair value of derivatives are recognized in earnings during the period of change, except for contracts designated as a cash flow hedge or that are probable of recovery in retail rates. Changes in the fair value of contracts probable of recovery in retail rates are deferred as regulatory assets or liabilities pursuant to SFAS 71.

Unrealized gains and losses on derivative contracts not held for trading purposes are presented on a gross basis in the consolidated statements of operations as operating revenue for sales contracts and as cost of sales and operating expense for purchase contracts and financial swaps. Unrealized and realized gains and losses from all derivative contracts held for trading purposes, including those where physical delivery is required, are presented on a net basis in the consolidated statements of operations as operating revenue.

In order to reduce the impact of fluctuations in forward prices of electricity and natural gas on PacifiCorp's results of operations, PacifiCorp initiated cash flow hedging in April 2006 for a portion of its derivative contracts, primarily comprised of electricity sales and natural gas purchase contracts. Changes in fair value of derivative contracts designated as cash flow hedges are recorded as other comprehensive income to the extent the hedge is effective in offsetting changes in future cash flows for forecasted electricity and natural gas purchase and sales transactions. Amounts included in other

Table of Contents

comprehensive income are reclassified to operating revenue or cost of sales when the forecasted sale or purchase transaction affects earnings, or when it is probable that the forecasted transaction will not occur.

PacifiCorp has the following types of commodity transactions:

<u>Wholesale electricity purchase and sales contracts</u> – PacifiCorp makes continuing projections of future retail and wholesale loads and future resource availability to meet these loads based on a number of criteria, including historical load and forward market and other economic information and experience. Based on these projections, PacifiCorp purchases and sells electricity on a forward yearly, quarterly, monthly, daily and hourly basis to match actual resources to actual energy requirements and sells any surplus at the prevailing market price. This process involves hedging transactions, which include the purchase and sale of firm energy under long-term contracts, forward physical contracts or financial contracts for the purchase and sale of a specified amount of energy at a specified price over a given period of time.

<u>Natural gas and other fuel purchase contracts</u> – PacifiCorp manages its natural gas supply requirements by entering into forward commitments for physical delivery of natural gas. PacifiCorp also manages its exposure to increases in natural gas supply costs through forward commitments for the purchase of physical natural gas at fixed prices and financial swap contracts that settle in cash based on the difference between a fixed price that PacifiCorp pays and a floating market-based price that PacifiCorp receives.

The fair values of derivative instruments, primarily used for non-trading purposes, as of the acquisition date are as follows (in millions):

	Preliminary Fair Value
Maturity:	
Less than 1 year	$ 123.8
1-3 years	132.6
4-5 years	10.9
Excess of 5 years	(259.4)
Total	$ 7.9
Reflected as:	
Current asset	$ 221.7
Non-current asset	345.3
Current liability	(97.9)
Non-current liability	(461.2)
Total	$ 7.9

Short-Term and Long-Term Debt

The fair values of short-term and long-term debt as of the acquisition date are as follows (in millions):

	Average Interest Rate	Preliminary Fair Value
Short-term debt — notes payable and commercial paper	4.8%	$ 184.4
Long-term debt:		
First mortgage bonds —		
4.3% to 8.8%, due through 2011	6.0	$ 901.7
5.0% to 9.2%, due 2012 to 2016	6.5	1,040.4
8.5% to 8.6%, due 2017 to 2021	8.5	5.0
6.7% to 8.5%, due 2022 to 2026	7.4	424.0
5.3% to 7.7%, due 2032 to 2036	6.3	800.0
Guaranty of pollution-control revenue bonds —		
Variable rates, due 2014	3.1	40.7
Variable rates, due 2014 to 2026	3.2	325.2
Variable rates, due 2025	3.2	175.8
3.4% to 5.7%, due 2014 to 2026	4.5	184.0
6.2%, due 2031	6.2	12.7
Preferred stock subject to mandatory redemption	—	45.0
Other	11.7%	28.4
		3,982.9
Less current portion		(220.6)
Total long-term debt		$3,762.3

The annual repayments of the long-term debt are as follows: period from acquisition to December 31, 2006 – $214.7 million; 2007 – $167.7 million; 2008 – $410.4 million; 2009 – $142.2 million; 2010 – $15.8 million; and thereafter – $3,039.5 million. Unamortized debt discounts and funds held by trustees totaled $7.4 million at March 21, 2006.

Additionally, PacifiCorp has in place an $800.0 million committed bank revolving credit agreement expiring on July 6, 2011. The credit agreement carries an interest rate that is generally based on LIBOR plus a margin that varies based on PacifiCorp's credit ratings and requires that PacifiCorp's ratio of consolidated debt to total capitalization not exceed 0.65 to 1. PacifiCorp is in compliance with all covenants related to its revolving credit agreement.

Pension and Postretirement Obligations

PacifiCorp sponsors defined benefit pension plans that cover the majority of its employees. In addition, certain bargaining unit employees participate in a joint trust plan to which PacifiCorp contributes. Benefits under the main plan are based on final average pay formulas. Pension costs are funded annually by no more than the maximum amount that can be deducted for federal income tax purposes.

PacifiCorp also provides health care and life insurance benefits through various plans for eligible retirees. The cost of other postretirement benefits is accrued over the active service period of employees. PacifiCorp funds other postretirement benefits through a combination of funding vehicles.

The measurement date for plan assets and obligations for the pension and postretirement benefit plans is December 31 of each year. The weighted-average discount rate and rate of increase in compensation levels assumed in the actuarial calculations used to determine benefit obligations for the pension and postretirement benefit plans were 5.75% and 4.00%, respectively, as of the most recent measurement date.

The projected benefit obligation, value of plan assets and funded status of the pension and postretirement benefit plans as of the acquisition date are as follows:

	Pension	Post-Retirement
Projected benefit obligation	$(1,338.5)	$ (581.9)
Plan assets at fair value	824.9	292.1
Funded status	$ (513.6)	$ (289.8)

The pension plan aggregated accumulated benefit obligation was $1,170.9 million and the fair value of assets was $828.6 million, measured as of December 31, 2005, and included contributions prior to the acquisition date. Included in the pension plan obligations are the PacifiCorp Retirement Plan (the ''Retirement Plan'') and the Supplemental Executive Retirement Plan (the ''SERP''), which currently have assets with a fair value that is less than the accumulated benefit obligation under the Retirement Plan and the SERP, primarily due to declines in the equity markets and historically low interest rate levels. Through the purchase price allocation, the resulting minimum pension liabilities were adjusted to the funded status of each plan and represent the pension and postretirement obligations as of the acquisition date. PacifiCorp continues to recover substantially all of its pension and postretirement costs in rates based on actuarial calculations utilizing pre-acquisition values.

Although the SERP had no qualified assets as of the acquisition date, PacifiCorp has a Rabbi trust that holds corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERP. Because this plan is nonqualified, the assets in the Rabbi trust are not considered plan assets. The cash surrender value of all of the policies included in the Rabbi trust plus the fair market value of other Rabbi trust investments was $36.4 million at the acquisition date, net of amounts borrowed against the cash surrender value.

Deferred Income Taxes

The net deferred tax liability as of the acquisition date consists of the following (in millions):

Deferred tax assets:	
Regulatory liabilities	$ 317.5
Employee benefits	171.2
Other	178.6
Total deferred tax assets	667.3
Deferred tax liabilities:	
Property, plant and equipment	1,591.0
Regulatory assets	658.9
Other	115.2
Total deferred tax liabilities	2,365.1
Net deferred tax liability	$1,697.8
Reflected as:	
Current liability	$ 16.9
Non-current liability	1,680.9
	$1,697.8

Pro Forma Financial Information

The following pro forma condensed consolidated results of operations assume that the acquisition of PacifiCorp was completed as of January 1, 2006 and 2005, respectively (in millions):

	Six-Month Periods Ended June 30,	
	2006	**2005**
Operating revenue	$5,823.9	$4,911.5
Net income available to common and preferred stockholders	$ 536.7	$ 386.0

The pro forma financial information represents the historical operating results of the combined company with adjustments for purchase accounting and is not necessarily indicative of the results of operations that would have been achieved if the acquisition had taken place at the beginning of each period presented.

4. Stockholders' Equity and Related Party Transactions

On February 9, 2006, following the effective date of the repeal of the Public Utility Holding Company Act of 1935, Berkshire Hathaway converted its 41,263,395 shares of MEHC's no par zero-coupon convertible preferred stock into an equal number of shares of MEHC's common stock. As a consequence, Berkshire Hathaway now consolidates the Company in its financial statements as a majority-owned subsidiary and will include the Company in its consolidated federal U.S. income tax return.

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 common equity of MEHC upon any requests authorized from time to time by the Board of Directors of MEHC. 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 the Company's regulated subsidiaries. Berkshire Hathaway will have up to 180 days to fund any such request. The Berkshire Equity Commitment will expire on February 28, 2011, was not used for the PacifiCorp acquisition and will not be used for future acquisitions.

On March 2, 2006, MEHC amended its Articles of Incorporation to (i) increase the amount of its common stock authorized for issuance to 115.0 million shares and (ii) no longer provide for the authorization to issue any preferred stock of MEHC.

On March 6, 2006, Mr. David L. Sokol, Chairman and Chief Executive Officer of MEHC, exercised 450,000 common stock options having an exercise price of $29.01 per share. Additionally, Mr. Sokol put 344,274 shares of common stock to MEHC for a purchase price of $50.0 million.

On March 21, 2006, Berkshire Hathaway and certain other of MEHC's existing stockholders and related companies invested $5,109.5 million, in the aggregate, in 35,237,931 shares of MEHC's common stock in order to provide equity funding for the PacifiCorp acquisition (see Note 3). The per-share value assigned to the shares of common stock issued, which were effected pursuant to a private placement and were exempt from the registration requirements of the Securities Act of 1933, as amended, was based on an assumed fair market value as agreed to by MEHC's stockholders.

On March 28, 2006, MEHC repurchased 11,724,138 shares of common stock from Berkshire Hathaway for an aggregate purchase price of $1,700.0 million.

At June 30, 2006 and December 31, 2005, Berkshire Hathaway and its affiliates held 11% mandatory redeemable preferred securities due from certain wholly owned subsidiary trusts of MEHC of $1,222.2 million and $1,289.2 million, respectively. Interest expense on these securities totaled $35.1 million and $40.6 million, respectively, for the three-month periods ended June 30, 2006 and 2005, and $70.6 million and $81.3 million, respectively, for the six-month periods ended June 30, 2006 and 2005.

5. Properties, Plants and Equipment, Net

Properties, plants and equipment, net consist of the following (in millions):

	Ranges of Estimated Useful Life	As of June 30, 2006	As of December 31, 2005
Utility generation and distribution system	5-85 years	$ 26,431.9	$ 10,499.1
Interstate pipeline assets	3-67 years	5,243.6	5,321.8
Independent power plants	10-30 years	1,190.4	1,384.6
Other assets	3-30 years	526.5	476.5
Total operating assets		33,392.4	17,682.0
Accumulated depreciation and amortization		(12,343.0)	(6,614.2)
Net operating assets		21,049.4	11,067.8
Construction in progress		1,597.6	847.6
Properties, plants and equipment, net		$ 22,647.0	$ 11,915.4

The utility generation and distribution system and interstate pipeline assets are the regulated assets of PacifiCorp, MidAmerican Funding, Northern Natural Gas, Kern River and CE Electric UK. At June 30, 2006 and December 31, 2005, accumulated depreciation and amortization related to the Company's regulated assets totaled $11.6 billion and $5.7 billion, respectively. Additionally, substantially all of the construction in progress at June 30, 2006 and December 31, 2005 relates to the construction of regulated assets.

6. Recent Debt Transactions

On March 24, 2006, MEHC completed a $1,700 million offering of unsecured senior bonds due 2036 (the ''Bonds''). The Bonds were issued at an offering price of 99.957%, will accrue interest at a rate of 6.125% per annum and will mature on April 1, 2036. Accrued interest on the Bonds is payable on April 1 and October 1 of each year, commencing on October 1, 2006, until the principal amount of the Bonds is paid in full. The proceeds were used to fund MEHC's exercise of its right to repurchase shares of its common stock previously issued to Berkshire Hathaway.

On June 15, 2006, MidAmerican Energy's 6.375% series of notes, totaling $160.0 million, matured.

On July 6, 2006, MEHC entered into a $600.0 million credit facility pursuant to the terms and conditions of an amended and restated credit agreement. The amended and restated credit agreement remains unsecured, carries a variable interest rate based on LIBOR or a base rate, at MEHC's option, plus a margin, and the termination date was extended to July 6, 2011. The facility continues to support letters of credit for the benefit of certain subsidiaries and affiliates.

Table of Contents

7. Other Income and Other Expense

Other income consists of the following (in millions):

	Three-Month Periods Ended June 30, 2006	Three-Month Periods Ended June 30, 2005	Six-Month Periods Ended June 30, 2006	Six-Month Periods Ended June 30, 2005
Gain on Mirant bankruptcy claim	$ —	$ —	$ 89.3	$ —
Gains from non-strategic assets and investments	32.1	8.4	44.8	19.9
Allowance for equity funds used during construction	15.0	6.0	22.5	10.7
Other	4.6	3.6	18.0	8.4
Total other income	$51.7	$18.0	$174.6	$39.0

Mirant Americas Energy Marketing (''Mirant'') Bankruptcy Claim

Mirant was one of the shippers that entered into a 15-year, 2003 Expansion Project, firm gas transportation contract (90,000 Dth per day) with Kern River (the ''Mirant Agreement'') and provided a letter of credit equivalent to 12 months of reservation charges as security for its obligations thereunder. In July 2003, Mirant filed for Chapter 11 bankruptcy protection and Kern River subsequently drew on the letter of credit and held the proceeds thereof, $14.8 million, as cash collateral. Kern River claimed $210.2 million in damages due to the rejection of the Mirant Agreement. The bankruptcy court ultimately determined that Kern River was entitled to a general unsecured claim of $74.4 million in addition to the $14.8 million cash collateral. In January 2006, Mirant emerged from bankruptcy and on February 6, 2006, a stipulated judgment was entered that allowed Kern River to receive a pro rata amount of shares of new Mirant stock determined by Kern River's allowed claim amount plus interest in relation to the unsecured creditor class of over $6 billion. In February 2006, Kern River received an initial distribution of such shares in payment of the majority of its allowed claim. Kern River sold all of the shares of new Mirant stock received from its allowed claim amount plus interest in the first quarter of 2006 and recognized a gain from those sales of $89.3 million.

Non-Strategic Assets and Investments

Included in gains from non-strategic assets and investments are gains at MidAmerican Funding from the disposition of common shares held in an electronic energy and metals trading exchange. In the second quarter of 2006, MidAmerican Funding sold a majority of these common shares and realized a pre-tax gain of $27.6 million. MidAmerican Funding donated its remaining shares to a charitable foundation and recognized a pre-tax gain and donation expense of $4.5 million as MidAmerican Funding's equity investment in the common shares was carried at zero cost.

8. Regulatory Matters

The following are updates to regulatory matters based upon changes that occurred during the six-month period ended June 30, 2006:

PacifiCorp

Utah

In March 2006, PacifiCorp filed a general rate case with the Utah Public Service Commission (''UPSC'') related to increased investments in Utah due to growing demand for electricity. In April 2006, PacifiCorp filed a revised case reflecting the effects of PacifiCorp's sale to MEHC, which reduced the original increase requested from $197.2 million to $194.1 million. In July 2006, a stipulation was reached with several parties and was filed with the UPSC. The stipulation calls for an annual increase of $115.0 million, or 9.95%, with $85.0 million of the increase effective December 11, 2006 and the remaining $30.0 million effective June 1, 2007. Under the terms of the stipulation, PacifiCorp has agreed not to file another rate case until after December 11, 2007. Hearings before the UPSC are set for August 2006.

Oregon

In February 2006, PacifiCorp filed a general rate case request with the Oregon Public Utility Commission (''OPUC'') for $112.0 million, which represents a 13.2% overall increase. The request is related to investments in generation, transmission and distribution infrastructure and increases in fuel and general operating expenses, including power plant maintenance. In August 2006, a settlement agreement with all parties was filed with the OPUC. PacifiCorp will receive an increase of $43.0 million effective January 1, 2007, which reflects $33.0 million for non-power cost items and up to $10.0 million for power costs. PacifiCorp's power costs will be updated via the existing annual transition adjustment mechanism with new rates effective January 1, 2008. PacifiCorp has agreed not to file a new rate case prior to September 1, 2007.

In September 2005, Oregon's governor signed into law Senate Bill 408. This legislation is intended to address differences between income taxes collected by Oregon public utilities currently in retail rates and actual taxes paid by the utilities or consolidated groups in which utilities are included for income tax reporting purposes. This legislation authorizes an automatic adjustment to rates based on the taxes paid to governmental entities on or after January 1, 2006. In July 2006, the OPUC issued an interim order establishing a method to determine federal, state and local taxes that are ''properly attributed'' to the regulated utility of a consolidated group using the lesser of defined stand alone taxes paid or taxes paid calculated using an apportionment formula based on a ratio of sales, payroll and property located in Oregon compared to the defined group for federal and state tax purposes applied to the taxes paid by the defined group. Therefore, the ratio of these factors and the federal taxes paid by Berkshire Hathaway and the state taxes paid by the defined group may impact the amount ''properly attributed'' to PacifiCorp. PacifiCorp filed comments in July 2006 seeking modifications on the interim order. A final order from the OPUC establishing the permanent rule is expected in September 2006. PacifiCorp will evaluate its legal and legislative options after the permanent rule is established.

In September 2005, the OPUC issued an order granting a general rate increase of $25.9 million, or an average increase of 3.2%, effective October 2005. PacifiCorp filed its general rate case in November 2004, and following four partial stipulations with participating parties, PacifiCorp's requested revenue requirement increase was $52.5 million. The OPUC's order reduced PacifiCorp's revenue requirement by $26.6 million based on the OPUC's interpretation of Senate Bill 408. In October 2005, PacifiCorp filed with the OPUC a motion for reconsideration and rehearing of the rate order generally on the basis that the tax adjustment was not made in compliance with applicable law. With the motion, PacifiCorp also filed a deferred accounting application with the OPUC to track revenues related to the disallowed tax expenses. In July 2006, a final order was issued by the OPUC affirming its initial application of Senate Bill 408. The order also modified the tax adjustment, resulting in an additional annual increase in PacifiCorp's revenue of $6.1 million, effective July 2006 as well as granting deferred accounting from October 2005 to July 2006. PacifiCorp is reviewing its legal and regulatory options.

Wyoming

In March 2006, the Wyoming Public Service Commission approved an agreement that settled the general rate case filed by PacifiCorp in October 2005 and a separate request filed by PacifiCorp in December 2005 to recover increased costs of net wholesale purchased power used to serve Wyoming customers. The agreement provides for an annual rate increase of $15.0 million effective March 1, 2006, an additional annual rate increase of $10.0 million effective July 1, 2006, a power cost adjustment mechanism and an agreement by the parties to support a forecast test year in the next general rate case application.

Washington

In May 2005, PacifiCorp filed a general rate case request with the Washington Utilities and Transportation Commission (''WUTC'') for $39.2 million annually, which was later reduced to $30.0 million. In April 2006, the WUTC issued an order denying PacifiCorp's request to increase retail

rates. The WUTC determined that application of PacifiCorp's cost allocation methodology failed to satisfy the statutory requirements that resources must benefit Washington ratepayers. In April 2006, PacifiCorp filed a petition for reconsideration of the order and requested an increase of not less than $11.0 million. PacifiCorp also filed a limited rate request seeking a rate increase of $7.0 million, which represents a 2.99% increase in rates. In June 2006, the WUTC suspended PacifiCorp's limited rate request and consolidated the request with the general rate case. In July 2006, the WUTC issued an order denying PacifiCorp's request for reconsideration and rejecting the 2.99% limited rate request filing. PacifiCorp is evaluating its legal and regulatory options for obtaining appropriate regulatory treatment in Washington.

MidAmerican Funding

On April 18, 2006, the Iowa Utilities Board (''IUB'') approved a settlement agreement filed in conjunction with MidAmerican Energy's application for up to 545 MW, based on nameplate ratings, of additional wind-powered generation capacity in Iowa. The settlement agreement extends the current revenue sharing mechanism through 2012 and extends MidAmerican Energy's and the Iowa Office of Consumer Advocate's commitments not to seek or support a general increase or decrease, respectively, in electric base rates through December 31, 2012.

Kern River

Kern River's 2004 general rate case hearing concluded in August 2005. On March 2, 2006, Kern River received an initial decision on the case from the administrative law judge, which, among other things, proposed an authorized rate of return of 9.34%. Kern River is currently authorized to collect an authorized rate of return of 13.25%. Briefs on exceptions were filed on April 3, 2006, and briefs opposing exceptions were filed on April 24, 2006. The administrative law judge's initial decision is non-binding and after briefing, the FERC will issue its initial decision on the case. The initial FERC decision, which may result in rate refunds, typically becomes binding on all parties while rehearing requests on the FERC decision and/or court appeals are pending. The initial FERC decision is not expected until late 2006 or early 2007. The final resolution of the rate case is dependent on receiving a final, non-appealable decision on the case from the FERC, or approval of a settlement of the case by the FERC.

9. Commitments and Contingencies

Environmental Matters

PacifiCorp and MidAmerican Energy are subject to numerous environmental laws, including the federal Clean Air Act and various state air quality laws; the Endangered Species Act; the Comprehensive Environmental Response, Compensation and Liability Act and similar state laws relating to environmental cleanups; the Resource Conservation and Recovery Act and similar state laws relating to the storage and handling of hazardous materials; and the Clean Water Act and similar state laws relating to water quality. These laws have the potential for impacting the Company's operations. Specifically, the Clean Air Act will likely continue to impact the operation of PacifiCorp's and MidAmerican Energy's generating facilities and will likely require PacifiCorp and MidAmerican Energy to reduce emissions from those facilities through the installation of additional or improved emission controls, purchase additional emission allowances, or to implement some combination thereof.

Air Quality

PacifiCorp and MidAmerican Energy are subject to applicable provisions of the Clean Air Act and related air quality standards promulgated by the United States Environmental Protection Agency (''EPA''). The Clean Air Act provides the framework for regulation of certain air emissions and permitting and monitoring associated with those emissions. PacifiCorp and MidAmerican Energy believe they are in material compliance with current air quality requirements.

Table of Contents

The EPA has in recent years implemented more stringent national ambient air quality standards for ozone and new standards for fine particulate matter. These standards set the minimum level of air quality that must be met throughout the United States. Areas that achieve the standards, as determined by ambient air quality monitoring, are characterized as being in attainment of the standard. Areas that fail to meet the standard are designated as being nonattainment areas. Generally, once an area has been designated as a nonattainment area, sources of emissions that contribute to the failure to achieve the ambient air quality standards are required to make emissions reductions. The EPA has concluded that the counties in Washington, Idaho, Montana, Wyoming, Colorado, Utah and Arizona, where PacifiCorp's major emission sources are located, and the entire state of Iowa, where MidAmerican Energy's major emission sources are located, are in attainment of the ozone and the current fine particulate matter standards.

In December 2005, the EPA proposed a revision of the ambient air quality standards for fine particles that would maintain the current annual standard and set a new, more stringent 24-hour standard for concentration of fine particulate in the ambient air. The EPA is scheduled to issue final rules in September 2006.

In March 2005, the EPA released the final Clean Air Mercury Rule (''CAMR''). The CAMR utilizes a market-based cap and trade mechanism to reduce mercury emissions from coal-burning power plants from the 1999 nationwide level of 48 tons to 15 tons at full implementation. The CAMR's two-phase reduction program requires initial reductions of mercury emission in 2010 and an overall reduction in mercury emissions from coal-burning power plants of 70% by 2018. Individual states are required to implement the CAMR or alternative requirements to achieve equivalent or greater mercury emission reductions through their state implementation plans.

In March 2005, the EPA released the final Clean Air Interstate Rule (''CAIR''), calling for reductions of sulfur dioxide (''SO_2'') and nitrogen oxides (''NO_x'') emissions in the eastern United States through, at each state's option, a market-based cap and trade system, emission reductions, or both. The state of Iowa has implemented rules that exercise the option of the market-based cap and trade system. While the state of Iowa has been determined to be in attainment of the ozone and fine particulate standards, Iowa has been found to significantly contribute to nonattainment of the fine particulate standard in Cook County, Illinois; Lake County, Indiana; Madison County, Illinois; St. Clair County, Illinois; and Marion County, Indiana. The EPA has also concluded that emissions from Iowa significantly contribute to ozone nonattainment in Kenosha and Sheboygan counties in Wisconsin and Macomb County, Michigan. Under the final CAIR, the first phase reductions of SO_2 emissions are effective on January 1, 2010, with the second phase reductions effective January 1, 2015. For NO_x, the first phase emissions reductions are effective January 1, 2009, and the second phase reductions are effective January 1, 2015. The CAIR calls for overall reductions of SO_2 and NO_x in Iowa of 68% and 67%, respectively, from 2003 levels by 2015.

The CAMR or the CAIR could, in whole or in part, be superseded or made more stringent by one of a number of multi-pollutant emission reduction proposals currently under consideration at the federal level, including pending legislative proposals that contemplate 70% to 90% reductions of SO_2, NO_X and mercury, as well as possible new federal regulation of carbon dioxide and other gases that may affect global climate change. In addition to any federal legislation that could be enacted by Congress to supersede the CAMR and the CAIR, the rules could be changed or overturned as a result of litigation. The sufficiency of the standards established by both the CAMR and the CAIR has been legally challenged in the United States District Court for the District of Columbia.

The EPA has initiated a regional haze program intended to improve visibility at specific federally protected areas. Some of PacifiCorp's and MidAmerican Energy's plants meet the threshold applicability criteria under the Clean Air Visibility Rules. PacifiCorp and other stakeholders are participating in the Western Regional Air Partnership to help develop the technical and policy tools needed to comply with this program, while MidAmerican Energy and other stakeholders are participating in the Central States Regional Air Partnership to help develop the technical and policy tools needed to comply with this program.

As of June 30, 2006, PacifiCorp's environmental contingencies principally consist of air quality matters. Pending or proposed air regulations will require PacifiCorp to reduce the emissions of SO_2, NO_x and other pollutants at its generating facilities below current levels. The acquisition of PacifiCorp by MEHC includes a regulatory commitment to spend approximately $812 million to reduce emissions at PacifiCorp's generating facilities to address existing and future air quality requirements. These costs and any additional expenditures necessitated by air quality regulations are expected to be recoverable through the ratemaking process.

MidAmerican Energy has implemented a planning process that forecasts the site-specific controls and actions that may be required to meet emissions reductions as promulgated by the EPA. In accordance with an Iowa law passed in 2001, MidAmerican Energy has on file with the IUB its current multi-year plan and budget for managing SO_2 and NO_X from its generating facilities in a cost-effective manner. The plan, which is required to be updated every two years, provides specific actions to be taken at each coal-fired generating facility and the related costs and timing for each action. Pursuant to an unrelated rate settlement agreement approved by the IUB on October 17, 2003, if prior to January 1, 2011, capital and operating expenditures to comply with air quality requirements cumulatively exceed $325 million, then MidAmerican Energy may seek to recover the additional expenditures from customers.

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 (1) beginning construction of a new major stationary source of an NSR-regulated pollutant or (2) 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 are subject to 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 a Best Available Control Technology analysis and evaluate the most effective emissions controls. These controls must be installed in order to receive a permit. Violations of NSR regulations, which may be alleged by the EPA, states, and environmental groups, among others, potentially subject a utility to material expenses for fines and other sanctions and remedies including requiring installation of enhanced pollution controls and funding supplemental environmental projects.

The EPA has requested from several utilities information and supporting documentation regarding their capital projects for various generating plants. The requests were issued as part of an industry-wide investigation to assess compliance with the NSR and the New Source Performance Standards of the Clean Air Act. In 2001 and 2003, PacifiCorp received requests for information from the EPA relating to PacifiCorp's capital projects at seven of its generating plants; PacifiCorp submitted information responsive to the requests, and there are currently no outstanding data requests pending from the EPA. In December 2002 and April 2003, MidAmerican Energy received requests from the EPA to provide documentation related to its capital projects from January 1, 1980, to April 2003 for a number of its generating plants. MidAmerican Energy has submitted information to the EPA in responses to these requests, and there are currently no outstanding data requests pending from the EPA. PacifiCorp and MidAmerican Energy cannot predict the outcome of these requests at this time.

In 2002 and 2003, the EPA proposed various changes to its NSR rules that clarify what constitutes routine repair, maintenance and replacement for purposes of triggering NSR requirements. These changes have been subject to legal challenge and, until such time as the legal challenges are resolved and the rules are effective, PacifiCorp and MidAmerican Energy will continue to manage projects at its generating plants in accordance with the rules in effect prior to 2002. In October 2005, the EPA proposed a rule that would change or clarify how emission increases are to be calculated for purposes of determining the applicability of the NSR permitting program for existing power plants.

In February 2005, the Kyoto Protocol became effective, requiring 35 developed countries to reduce greenhouse gas emissions by approximately 5% between 2008 and

2012. While the United States did not ratify the protocol, the ratification and implementation of its requirements in other

countries has resulted in increased attention to climate change in the United States. In 2005, the Senate adopted a ‘‘sense of the Senate’’ resolution that puts the Senate on record that Congress should enact a comprehensive and effective national program of mandatory, market-based limits and incentives on emissions of greenhouse gases that slow, stop, and reverse the growth of such emissions at a rate and in a manner that will not significantly harm the United States economy; and will encourage comparable action by other nations that are major trading partners and key contributors to global emissions. It is anticipated that the resolution may be further addressed by Congress in 2006. While debate continues at the national level over the direction of domestic climate policy, several states are developing state-specific or regional legislative initiatives to reduce greenhouse gas emissions. In December 2005, the states of Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York and Vermont signed a mandatory regional pact to reduce greenhouse gas emissions that would become effective in 2009 and ultimately would require a reduction in greenhouse gas emissions of 10 percent from 1990 levels. An executive order signed by California’s governor in June 2005 would reduce greenhouse gas emissions in that state to 2000 levels by 2010, to 1990 levels by 2020 and 80 percent below 1990 levels by 2050. In addition, California is seeking to apply a greenhouse gas emission performance standard to all electricity generated within the state or delivered from outside the state that is no higher than the greenhouse gas emission levels of a state-of-the-art combined-cycle natural gas generation facility.

Litigation was filed in the federal district court for the southern district of New York seeking to require reductions of carbon dioxide emissions from generating facilities of five large electric utilities. The court dismissed the public nuisance suit, holding that such critical issues affecting the United States such as greenhouse gas emissions reductions are not the domain of the court and should be resolved by the Executive Branch and the U.S. Congress. This ruling has been appealed to the Second Circuit Court of Appeals. The outcome of climate change litigation and federal and state initiatives cannot be determined at this time; however, adoption of stringent limits on greenhouse gas emissions could significantly impact the Company’s fossil-fueled facilities and, therefore, its results of operations.

The EPA’s regulation of certain pollutants under the Clean Air Act, and its failure to regulate other pollutants, is being challenged by various lawsuits brought by both individual state attorney generals and environmental groups. To the extent that these actions may be successful in imposing additional and/or more stringent regulation of emissions on fossil-fueled facilities in general and PacifiCorp’s and MidAmerican Energy’s facilities in particular, such actions could significantly impact the Company’s fossil-fueled facilities and, therefore, its results of operations.

Hydroelectric Relicensing

PacifiCorp’s hydroelectric portfolio consists of 51 plants with an aggregate facility net owned capacity of 1,159.4 MW. The FERC regulates 93.9% of the installed capacity of this portfolio through 18 individual licenses. Several of PacifiCorp’s hydroelectric plants are in some stage of relicensing with the FERC. Hydroelectric relicensing and the related environmental compliance requirements are subject to uncertainties. PacifiCorp expects that future costs relating to these matters may be significant and will consist primarily of additional relicensing costs, operations and maintenance expense, and capital expenditures. Electricity generation reductions may result from the additional environmental requirements. PacifiCorp had incurred $73.5 million in costs as of June 30, 2006, for ongoing hydroelectric relicensing, which are reflected in properties, plants and equipment, net in the accompanying consolidated balance sheet. PacifiCorp expects that these and future costs will be included in rates and, as such, will not have a material adverse impact on PacifiCorp’s consolidated financial position or results of operations.

In February 2004, PacifiCorp filed with the FERC a final application for a new license to operate the 161.4 MW Klamath hydroelectric project. The FERC is scheduled to complete its required analysis by January 2007. The U.S. Departments of Interior and Commerce filed proposed licensing terms and conditions with the FERC in March 2006; PacifiCorp filed alternatives to the federal agencies’ proposal and challenges to its factual assumptions in April 2006. PacifiCorp continues to participate in the mediated settlement discussions with state and federal agencies, Native American tribes and other stakeholders in an effort to reach a comprehensive agreement on project relicensing. As of June 30,

2006, PacifiCorp has incurred costs of $38.1 million, which are reflected in properties, plants and equipment, net in the accompanying consolidated balance sheet, in the relicensing of the Klamath project. While the costs of implementing new license provisions cannot be determined until such time as a new license is issued, such costs could be significant.

Mine Reclamation

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. These obligations mandate that mine property be restored consistent with specific standards and the approved reclamation plan. PacifiCorp’s mining operations are subject to these reclamation and closure requirements. Significant expenditures are being incurred for both ongoing and final reclamation. PacifiCorp’s estimated mine and plant reclamation costs for its coal mines was $137.5 million at June 30, 2006 and is the asset retirement obligation for these mines, which is reflected in other long-term accrued liabilities in the accompanying consolidated balance sheet. PacifiCorp has established trusts for the investment of funds for mine and plant reclamation. The fair value of the assets held in trusts was $99.6 million at June 30, 2006, and is reflected in other investments in the accompanying consolidated balance sheet.

Nuclear Decommissioning

Expected nuclear decommissioning costs for Quad Cities Station have been developed based on a site-specific decommissioning study that includes decontamination, dismantling, site restoration, dry fuel storage cost and an assumed shutdown date. Quad Cities Station nuclear decommissioning costs are included in base rates in MidAmerican Energy's Iowa tariffs. MidAmerican Energy's share of estimated decommissioning costs for Quad Cities Station was $167.7 million and $163.0 million as of June 30, 2006 and December 31, 2005, respectively, and is the asset retirement obligation for Quad Cities Station, which is reflected in other long-term accrued liabilities in the accompanying consolidated balance sheets. MidAmerican Energy has established trusts for the investment of funds for decommissioning the Quad Cities Station. The fair value of the assets held in the trusts was $234.6 million and $228.1 million, respectively, as of June 30, 2006 and December 31, 2005, and is reflected in other investments in the accompanying consolidated balance sheets. MidAmerican Energy's depreciation and amortization includes costs for Quad Cities Station decommissioning. The regulatory provision charged to expense is equal to the funding that is being collected in Iowa rates.

Accrued Environmental Costs

The Company's policy is to accrue environmental clean-up costs of a non-capital nature when those costs are believed to be probable and can be reasonably estimated. The quantification of environmental exposures is based on assessments of many factors, including changing laws and regulations, advancements in environmental technologies, the quality of information available related to specific sites, the assessment stage of each site investigation, preliminary findings and the length of time involved in remediation or settlement. The liability recorded at June 30, 2006 and December 31, 2005 was $43.4 million and $7.5 million, respectively.

Legal Matters

In addition to the proceeding described below, the Company is currently party to various items of litigation or arbitration in the normal course of business, none of which are reasonably expected by the Company to have a material adverse effect on its financial position, results of operations or cash flows.

Table of Contents

CalEnergy Generation–Foreign

Pursuant to the share ownership adjustment mechanism in the CE Casecnan stockholder agreement, which is based upon pro forma financial projections of the Casecnan project prepared following commencement of commercial operations, in February 2002, MEHC's indirect wholly-owned subsidiary, CE Casecnan Ltd., advised the minority stockholder 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. On July 8, 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 On January 21, 2004, CE Casecnan Ltd., LPG and CE Casecnan entered into a status quo agreement pursuant to which the parties agreed to set aside certain distributions related to the shares subject to the LPG dispute and CE Casecnan agreed not to take any further actions with respect to such distributions without at least 15 days prior notice to LPG. Accordingly, 15% of the CE Casecnan dividend distributions declared in 2004, 2005 and 2006, totaling $26.0 million, was set aside in a separate bank account in the name of CE Casecnan and is shown as restricted cash and short-term investments and other current liabilities in the accompanying consolidated balance sheets.

On August 4, 2005, the court issued a decision, ruling in favor of LPG on five of the eight disputed issues in the first phase of the litigation. On September 12, 2005, LPG filed a motion seeking the release of the funds which have been set aside pursuant to the status quo agreement referred to above. MEHC and CE Casecnan Ltd. filed an opposition to the motion on October 3, 2005, and at the hearing on October 26, 2005, the court denied LPG's motion. On January 3, 2006, the court entered a judgment in favor of LPG against CE Casecnan Ltd. According to the judgment LPG would retain its ownership of 15% of the shares of CE Casecnan and distributions of the amounts deposited into escrow plus interest at 9% per annum. On February 28, 2006, CE Casecnan Ltd. filed an appeal of this judgment and the August 4, 2005 decision. Initial briefs and reply briefs were filed May 24, 2006 and August 1, 2006, respectively. The appeal is expected to be resolved sometime in 2007. The impact, if any, of this litigation on the Company cannot be determined at this time.

In February 2003, San Lorenzo Ruiz Builders and Developers Group, Inc. (''San Lorenzo''), an original shareholder substantially all of whose shares in CE Casecnan were purchased by MEHC in 1998, threatened to initiate legal action against the Company in the Philippines in connection with certain aspects of its option to repurchase such shares. On July 1, 2005, MEHC and CE Casecnan Ltd. commenced an action against San Lorenzo in the District Court of Douglas County, Nebraska, seeking a declaratory judgment as to MEHC's and CE Casecnan Ltd.'s rights vis-à-vis San Lorenzo in respect of such shares. San Lorenzo filed a motion to dismiss on September 19, 2005. Subsequently, San Lorenzo purported to exercise its option to repurchase such shares. On January 30, 2006, San Lorenzo filed a counterclaim against MEHC and CE Casecnan Ltd. seeking declaratory relief that it has effectively exercised its option to purchase 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. On March 9, 2006, the court granted San Lorenzo's motion to dismiss, but has since permitted MEHC and CE Casecnan Ltd. to file an amended complaint incorporating the purported exercise of the option. The impact, if any, of San Lorenzo's purported exercise of its option and the Nebraska litigation on the Company cannot be determined at this time. The Company intends to vigorously defend the counterclaims.

10. Comprehensive Income

The components of comprehensive income (loss) are as follows (in millions):

	Three-Month Periods Ended June 30, 2006	2005	Six-Month Periods Ended June 30, 2006	2005
Net income	$153.0	$ 99.7	$402.0	$ 252.1
Other comprehensive income (loss):				
Foreign currency translation	120.1	(91.6)	136.3	(116.0)
Cash flow hedges, net of tax of $(3.5); $(25.1); $21.6; and $(27.8), respectively	(4.8)	(37.5)	35.5	(43.5)
Minimum pension liability, net of tax of $(5.5); $5.0; $(6.4); and $4.5, respectively	(12.9)	11.6	(14.8)	12.1
Marketable securities, net of tax of $(1.4); $ —; $(0.8); and $—, respectively	(2.1)	—	(1.1)	—
Total comprehensive income (loss)	$253.3	$(17.8)	$557.9	$ 104.7

11. Retirement Plans

PacifiCorp

PacifiCorp sponsors noncontributory defined benefit pension plans that cover the majority of its employees. In addition, certain bargaining unit employees participate in a joint trust plan to which PacifiCorp contributes. PacifiCorp also maintains noncontributory, nonqualified defined benefit supplemental executive retirement plans for active and retired participants. PacifiCorp also provides health care and life insurance benefits through various plans for eligible retirees. Net periodic benefit cost for the three-month period ended June 30, 2006 and for the period from acquisition to June 30, 2006 for the pension, including supplemental retirement, and postretirement benefit plans included the following components for PacifiCorp (in millions):

	Three-Month Period Ended June 30, 2006		Period from Acquisition to June 30, 2006	
	Pension	Post-retirement	Pension	Post-retirement
Service cost	$ 7.5	$ 2.3	$ 8.6	$ 2.6
Interest cost	18.8	8.2	21.1	9.1
Expected return on plan assets	(18.1)	(6.5)	(20.5)	(7.3)
Amortization of net transition balance	0.7	3.0	1.0	3.4
Amortization of prior service cost	0.3	0.7	0.3	0.8
Amortization of prior year loss	6.7	1.5	7.4	1.5
Curtailment loss	0.7	—	0.7	—
Net periodic benefit cost	$ 16.6	$ 9.2	$ 18.6	$10.1

PacifiCorp expects to contribute $80.6 million and $56.7 million, respectively, to its pension and postretirement plans during the period from acquisition to December 31, 2006. For the period from acquisition to June 30, 2006, $73.7 million and $29.3 million, respectively, of contributions have been made to the pension and postretirement plans.

MidAmerican Funding

MidAmerican Energy sponsors a noncontributory defined benefit pension plan covering substantially all employees of MEHC and its domestic energy subsidiaries, except for PacifiCorp and its subsidiaries. MidAmerican Energy also sponsors certain postretirement health care and life insurance benefits covering substantially all retired employees of MEHC and its domestic energy subsidiaries, except for PacifiCorp and its subsidiaries. Non-union employees hired after June 30, 2004

and union employees hired after June 30, 2006, under contracts covering substantially all of MidAmerican Energy's union employees, are not eligible for postretirement benefits other than pensions. Net periodic benefit cost for the three-month and six-month periods ended June 30 for the pension, including supplemental retirement, and postretirement benefit plans included the following components for MEHC and the aforementioned subsidiaries (in millions):

	Three-Month Periods Ended June 30, 2006	2005	Six-Month Periods Ended June 30, 2006	2005
Pension:				
Service cost	$ 6.1	$ 6.7	$ 12.5	$ 13.4
Interest cost	9.2	9.2	18.7	18.4
Expected return on plan assets	(9.1)	(9.5)	(18.8)	(19.0)
Amortization of prior service cost	0.6	0.7	1.2	1.3
Amortization of prior year loss	0.3	0.3	0.6	0.7
Net periodic benefit cost	$ 7.1	$ 7.4	$ 14.2	$ 14.8

	Three-Month Periods Ended June 30, 2006	2005	Six-Month Periods Ended June 30, 2006	2005
Postretirement:				
Service cost	$ 1.7	$ 1.7	$ 3.4	$ 3.4
Interest cost	3.2	3.6	6.7	7.2
Expected return on plan assets	(2.3)	(2.3)	(4.8)	(4.6)
Amortization of net transition balance	0.1	0.6	0.7	1.2
Amortization of prior service cost	(0.1)	—	(0.1)	—

Amortization of prior year loss	0.9	0.3	1.3	0.7
Net periodic benefit cost	$ 3.5	$ 3.9	$ 7.2	$ 7.9

The Company expects to contribute $5.9 million and $15.6 million, respectively, in 2006 to its pension and postretirement plans. As of June 30, 2006, $3.0 million and $6.7 million, respectively, of contributions have been made to the pension and postretirement plans.

CE Electric UK

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 substantially all employees of CE Electric UK's certain wholly-owned subsidiaries. Net periodic benefit cost for the pension plan included the following components for CE Electric UK (in millions):

	Three-Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2006	2005	2006	2005
Service cost	$ 4.6	$ 3.9	$ 9.0	$ 7.9
Interest cost	19.3	19.5	37.8	39.4
Expected return on plan assets	(25.2)	(24.7)	(49.3)	(49.9)
Amortization of prior service cost	0.5	0.5	0.9	1.0
Amortization of prior year loss	8.0	5.6	16.1	11.2
Net periodic benefit cost	$ 7.2	$ 4.8	$ 14.5	$ 9.6

Employer contributions to the UK Plan, including £23.1 million for the existing funding deficiency, are expected to be £35.0 million for 2006. As of June 30, 2006, £17.5 million, or

Table of Contents

$31.3 million, of contributions have been made to the UK Plan, including £11.6 million, or $20.7 million, in respect of the existing funding deficiency.

12. Segment Information

The Company has identified eight reportable segments: PacifiCorp, MidAmerican Funding, Northern Natural Gas, Kern River, CE Electric UK, CalEnergy Generation-Foreign, CalEnergy Generation-Domestic, and HomeServices. The Company's determination of reportable segments considers the strategic units under which the Company is 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. The reportable segment financial information includes all necessary adjustments and eliminations needed to conform to the Company's significant accounting policies including the allocation of goodwill. Information related to the Company's reportable segments is shown below (in millions):

	Three-Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2006	2005	2006	2005
Operating revenue:				
PacifiCorp	$ 859.9	$ —	$ 936.4	$ —
MidAmerican Funding	761.6	619.7	1,803.3	1,476.0
Northern Natural Gas	103.0	61.9	316.7	263.1
Kern River	86.2	79.2	165.5	157.8
CE Electric UK	215.9	214.9	426.3	454.1
CalEnergy Generation — Foreign	73.8	72.1	159.1	144.3
CalEnergy Generation — Domestic	8.0	8.7	15.5	16.6
HomeServices	517.4	554.2	872.9	916.5
Total reportable segments	2,625.8	1,610.7	4,695.7	3,428.4
Corporate/other(1)	(8.3)	(6.3)	(23.6)	(19.8)
Total operating revenue	$2,617.5	$1,604.4	$4,672.1	$3,408.6
Depreciation and amortization:				
PacifiCorp	$ 115.8	$ —	$ 129.1	$ —
MidAmerican Funding	87.2	74.0	162.2	137.8
Northern Natural Gas(2)	14.2	(14.3)	28.4	2.9
Kern River	20.0	15.6	46.6	31.2
CE Electric UK	33.7	34.1	64.4	69.8
CalEnergy Generation — Foreign	22.5	22.7	45.1	45.4
CalEnergy Generation — Domestic	1.9	2.2	4.1	4.4
HomeServices	10.6	4.4	15.6	8.7
Total reportable segments	305.9	138.7	495.5	300.2
Corporate/other(1)	(1.9)	(1.3)	(3.5)	(3.2)
Total depreciation and amortization	$ 304.0	$ 137.4	$ 492.0	$ 297.0

Table of Contents

	Three-Month Periods Ended June 30,		Six-Month Periods Ended June 30,	
	2006	2005	2006	2005
Operating income:				
PacifiCorp	$ 130.8	$ —	$ 153.3	$ —
MidAmerican Funding	79.2	58.6	213.7	157.9

Northern Natural Gas	19.4	38.5	143.8	149.7
Kern River	52.0	47.9	92.2	97.0
CE Electric UK	117.3	114.9	231.3	240.6
CalEnergy Generation — Foreign	43.9	43.4	101.3	87.2
CalEnergy Generation — Domestic	3.5	5.2	6.5	9.5
HomeServices	34.9	50.8	34.7	58.9
Total reportable segments	481.0	359.3	976.8	800.8
Corporate/other(1)	(9.1)	(24.7)	(42.4)	(41.7)
Total operating income	471.9	334.6	934.4	759.1
Interest expense	(308.1)	(224.1)	(529.8)	(455.7)
Capitalized interest	10.3	4.6	14.9	8.2
Interest and dividend income	18.2	15.0	33.6	23.4
Other income	51.7	18.0	174.6	39.0
Other expense	(7.3)	(1.5)	(8.6)	(4.8)
Total income from continuing operations before income tax expense, minority interest and preferred dividends of subsidiaries and equity income	$ 236.7	$ 146.6	$ 619.1	$ 369.2
Interest expense:				
PacifiCorp	$ 69.2	$ —	$ 77.4	$ —
MidAmerican Funding	38.8	33.5	77.9	67.3
Northern Natural Gas	12.5	14.0	25.0	27.3
Kern River	17.8	18.3	35.8	36.8
CE Electric UK	53.6	53.1	103.2	112.7
CalEnergy Generation — Foreign	5.6	8.0	11.2	16.6
CalEnergy Generation — Domestic	4.4	4.6	8.9	9.2
HomeServices	0.5	0.6	1.0	1.2
Total reportable segments	202.4	132.1	340.4	271.1
Corporate/other(1)	105.7	92.0	189.4	184.6
Total interest expense	$ 308.1	$ 224.1	$ 529.8	$ 455.7

Table of Contents

	As of June 30, 2006	As of December 31, 2005
Total assets:		
PacifiCorp	$14,372.9	$ —
MidAmerican Funding	7,835.4	8,003.4
Northern Natural Gas	2,217.4	2,245.3
Kern River	2,021.3	2,099.6
CE Electric UK	6,353.4	5,742.7
CalEnergy Generation — Foreign	571.1	643.1
CalEnergy Generation — Domestic	536.0	555.1
HomeServices	813.3	814.3
Total reportable segments	34,720.8	20,103.5
Corporate/other(1)	277.1	267.2
Total assets	$34,997.9	$20,370.7

(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 (i) corporate functions, including administrative costs, interest expense, corporate cash and related interest income, (ii) intersegment eliminations and (iii) fair value adjustments relating to acquisitions.

(2) The negative depreciation and amortization at Northern Natural Gas for the three-month period ended June 30, 2005, is due to the settlement of its consolidated rate case in June 2005.

Goodwill is allocated to each reportable segment included in total assets above. Goodwill as of December 31, 2005 and the changes for the six-month period ended June 30, 2006 by reportable segment are as follows (in millions):

	PacifiCorp	MidAmerican Funding	Northern Natural Gas	Kern River	CE Electric UK	CalEnergy Generation Domestic	Home-Services	Total
Goodwill at December 31, 2005	$ —	$ 2,117.6	$ 327.1	$33.9	$1,207.2	$ 72.4	$ 398.0	$4,156.2
Goodwill from acquisitions	1,074.0	—	—	—	—	—	36.1	1,110.1
Reclassification of intangible assets(1)	—	—	—	—	—	—	(44.9)	(44.9)
Foreign currency transZlation	—	—	—	—	67.3	—	—	67.3
Other(2)	—	1.1	(13.3)	—	(0.7)	(0.2)	(0.2)	(13.3)
Goodwill at June 30, 2006	$1,074.0	$ 2,118.7	$ 313.8	$33.9	$1,273.8	$ 72.2	$ 389.0	$5,275.4

(1) During the three-month period ending June 30, 2006, the Company reclassified $44.9 million of identifiable intangible assets from goodwill that principally related to trade names at HomeServices that were determined to have finite lives.

(2) Other goodwill adjustments include primarily income tax adjustments.

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
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, 2005 and 2004, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2005. Our audits also included the financial statement schedules listed in the Index at Item 15. 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, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, 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 3, 2006

Table of Contents

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

	As of December 31,	
	2005	**2004**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 357,845	$ 837,353
Short-term investments	38,393	123,550
Restricted cash and short-term investments	102,900	129,316
Accounts receivable, net	802,599	695,761
Amounts held in trust	108,546	111,708
Inventories	128,184	125,079
Other current assets	194,131	141,194
Total current assets	1,732,598	2,163,961
Properties, plants and equipment, net	11,915,413	11,607,264
Goodwill	4,156,180	4,306,751
Regulatory assets	441,098	451,830
Other investments	798,683	261,575
Equity investments	236,209	216,935
Deferred charges and other assets	912,779	895,246
Total assets	$20,192,960	$19,903,562
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 523,602	$ 410,319
Accrued interest	198,263	197,813
Accrued property and other taxes	189,099	166,639
Amounts held in trust	108,546	111,708
Other liabilities	451,018	420,452
Short-term debt	70,066	9,090
Current portion of long-term debt	313,661	1,145,598
Current portion of parent company subordinated debt	234,021	188,543
Total current liabilities	2,088,276	2,650,162
Other long-term accrued liabilities	2,226,904	2,171,616
Parent company senior debt	2,776,211	2,771,957
Parent company subordinated debt	1,354,106	1,585,810
Subsidiary and project debt	6,836,626	6,304,923
Deferred income taxes	1,361,874	1,281,833
Total liabilities	16,643,997	16,766,301
Deferred income	53,931	62,443
Minority interest	21,419	14,119
Preferred securities of subsidiaries	88,362	89,540
Commitments and contingencies (Note 20)		
Stockholders' equity:		
Zero coupon convertible preferred stock − authorized 50,000 shares, no par value; 41,263 shares issued and outstanding	—	—
Common stock − authorized 60,000 shares, no par value; 9,281 and 9,081 shares issued and outstanding at December 31, 2005 and 2004, respectively	—	—
Additional paid-in capital	1,963,343	1,950,663
Retained earnings	1,719,497	1,156,843
Accumulated other comprehensive loss, net	(297,589)	(136,347)
Total stockholders' equity	3,385,251	2,971,159
Total liabilities and stockholders' equity	$20,192,960	$19,903,562

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

Table of Contents

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

	Year Ended December 31, 2005	2004	2003
Operating revenue	$7,115,539	$6,553,388	$5,965,630
Costs and expenses:			
Cost of sales	3,284,876	2,751,856	2,400,536
Operating expense	1,693,783	1,637,922	1,512,345
Depreciation and amortization	608,198	638,209	602,934
Total costs and expenses	5,586,857	5,027,987	4,515,815
Operating income	1,528,682	1,525,401	1,449,815
Other income (expense):			
Interest expense	(890,979)	(903,217)	(760,956)
Capitalized interest	16,716	20,040	30,494
Interest and dividend income	58,070	38,889	47,908
Other income	74,516	128,205	96,643
Other expense	(22,127)	(10,125)	(5,913)
Total other income (expense)	(763,804)	(726,208)	(591,824)
Income from continuing operations before income tax expense, minority interest and preferred dividends of subsidiaries and equity income	764,878	799,193	857,991
Income tax expense	244,709	264,986	270,276
Minority interest and preferred dividends of subsidiaries	15,962	13,301	183,203
Income from continuing operations before equity income	504,207	520,906	404,512
Equity income	53,313	16,861	38,224
Income from continuing operations	557,520	537,767	442,736
Income (loss) from discontinued operations, net of tax (Note 17)	5,134	(367,561)	(27,118)
Net income available to common and preferred stockholders	$ 562,654	$ 170,206	$ 415,618

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

Table of Contents

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
FOR THE THREE YEARS ENDED DECEMBER 31, 2005
(Amounts in thousands)

	Outstanding Common Shares	Additional Paid-in Capital	Common Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Total
Balance, January 1, 2003	9,281	$ —	$1,956,509	$ 584,009	$ (246,235)	$2,294,283
Net income	—	—	—	415,618	—	415,618
Other comprehensive income:						
Foreign currency translation adjustment	—	—	—	—	58,148	58,148
Fair value adjustment on cash flow hedges, net of tax of $7,202	—	—	—	—	16,769	16,769
Minimum pension liability adjustment, net of tax of $(6,425)	—	—	—	—	(14,989)	(14,989)
Unrealized gains on securities, net of tax of $566	—	—	—	—	848	848
Total comprehensive income						476,394
Other equity transactions	—	—	768	—	—	768
Balance, December 31, 2003	9,281	—	1,957,277	999,627	(185,459)	2,771,445
Net income	—	—	—	170,206	—	170,206
Other comprehensive income:						
Foreign currency translation adjustment	—	—	—	—	107,370	107,370
Fair value adjustment on cash flow hedges, net of tax of $(6,069)	—	—	—	—	(12,270)	(12,270)
Minimum pension liability adjustment, net of tax of $(19,898)	—	—	—	—	(46,429)	(46,429)
Unrealized gains on securities, net of tax of $294	—	—	—	—	441	441
Total comprehensive income						219,318
Common stock purchase	(200)	—	(7,010)	(12,990)	—	(20,000)
Other equity transactions	—	—	396	—	—	396
Balance, December 31, 2004	9,081	—	1,950,663	1,156,843	(136,347)	2,971,159
Net income	—	—	—	562,654	—	562,654
Other comprehensive income:						
Foreign currency translation adjustment	—	—	—	—	(186,156)	(186,156)
Fair value adjustment on cash flow hedges, net of tax of $(9,828)	—	—	—	—	(19,541)	(19,541)
Minimum pension liability						

adjustment, net of tax of $17,994	—	—	—	—	43,724	43,724
Unrealized gains on securities, net of tax of $487	—	—	—	—	731	731
Total comprehensive income						401,412
Exercise of common stock options	200	—	5,801	—	—	5,801
Tax benefit from exercise of common stock options	—	—	6,236	—	—	6,236
Other equity transactions	—	—	643	—	—	643
Balance, December 31, 2005	9,281	$ —	$1,963,343	$1,719,497	$ (297,589)	$3,385,251

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

Table of Contents

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

	Year Ended December 31,		
	2005	**2004**	**2003**
Cash flows from operating activities:			
Income from continuing operations	$ 557,520	$ 537,767	$ 442,736
Adjustments to reconcile income from continuing operations to cash flows from continuing operations:			
Distributions less income on equity investments	(18,927)	20,022	40,160
Gain on other items, net	(6,338)	(71,757)	(29,264)
Depreciation and amortization	608,198	638,209	602,934
Amortization of regulatory assets and liabilities	38,725	(1,586)	(14,363)
Amortization of deferred financing costs	16,110	20,875	27,748
Provision for deferred income taxes	129,964	176,591	220,136
Other	(37,690)	16,981	8,211
Changes in other items:			
Accounts receivable and other current assets	(136,013)	(43,600)	(25,900)
Accounts payable and other accrued liabilities	167,351	171,457	(17,835)
Deferred income	(7,832)	(6,465)	(9,344)
Net cash flows from continuing operations	1,311,068	1,458,494	1,245,219
Net cash flows from discontinued operations	(262)	(33,846)	(27,296)
Net cash flows from operating activities	1,310,806	1,424,648	1,217,923
Cash flows from investing activities:			
Capital expenditures relating to operating projects	(796,319)	(778,300)	(616,804)
Construction and other development costs	(399,918)	(401,090)	(602,564)
Purchases of available-for-sale securities	(2,842,392)	(2,819,701)	(1,937,834)
Proceeds from sale of available-for-sale securities	2,913,060	2,737,999	1,900,152
Purchase of other investments	(556,590)	—	—
Proceeds from sale of other investments	—	—	288,750
Acquisitions, net of cash acquired	(10,247)	(36,706)	(54,263)
Proceeds from sale of assets	102,825	8,602	13,113
Proceeds from notes receivable	—	169,210	—
Proceeds from (purchase of) affiliate notes	4,391	14,118	(32,406)
(Increase) decrease in restricted cash and investments	26,652	(18,455)	(60,426)
Other	775	25,257	19,976
Net cash flows from continuing operations	(1,557,763)	(1,099,066)	(1,082,306)
Net cash flows from discontinued operations	6,423	966	(11,666)
Net cash flows from investing activities	(1,551,340)	(1,098,100)	(1,093,972)
Cash flows from financing activities:			
Proceeds from subsidiary and project debt	1,050,578	375,351	1,157,649
Proceeds from parent company senior debt	—	249,765	449,295
Repayments of subsidiary and project debt	(875,433)	(368,417)	(1,490,986)
Repayments of parent company senior and subordinated debt	(448,544)	(100,000)	(412,551)
Net proceeds from (repayment of) subsidiary short-term debt	10,443	(43,949)	(31,750)
Net proceeds from parent company revolving credit facility	51,000	—	—
Purchase and retirement of common stock	—	(20,000)	—
Other	(7,193)	(60,868)	(28,306)
Net cash flows from continuing operations	(219,149)	31,882	(356,649)
Net cash flows from discontinued operations	—	(137,297)	(1,407)
Net cash flows from financing activities	(219,149)	(105,415)	(358,056)
Effect of exchange rate changes	(19,825)	28,531	27,364
Net change in cash and cash equivalents	(479,508)	249,664	(206,741)
Cash and cash equivalents at beginning of period	837,353	587,689	794,430
Cash and cash equivalents at end of period	$ 357,845	$ 837,353	$ 587,689

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

Table of Contents

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Operations

MidAmerican Energy Holdings Company (''MEHC'') and its subsidiaries (together with MEHC, the ''Company'') are organized and managed as seven distinct platforms: MidAmerican Funding, LLC (''MidAmerican Funding'') (which primarily includes MidAmerican Energy Company (''MidAmerican Energy'')), Kern River Gas Transmission Company (''Kern River''), Northern Natural Gas Company (''Northern Natural Gas''), 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 (the subsidiaries owning the Upper Mahiao, Malitbog and Mahanagdong Projects (collectively the ''Leyte Projects'') and the Casecnan Project), CalEnergy Generation-Domestic (the subsidiaries owning 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 a combined electric and natural gas utility company in the United States, two natural gas pipeline companies in the United States, two electricity distribution companies in Great Britain, a diversified portfolio of domestic and international independent power projects and the second largest residential real estate brokerage firm in the United States.

On March 14, 2000, MEHC and an investor group including Berkshire Hathaway Inc. (''Berkshire Hathaway''), Walter Scott, Jr., a director of MEHC, David L. Sokol, Chairman and Chief Executive Officer of MEHC, and Gregory E. Abel, President and Chief Operating Officer of MEHC, executed a definitive agreement and plan of merger whereby the investor group acquired all of the outstanding common stock of MEHC (the ''Teton Transaction''). As of December 31, 2005 Walter Scott, Jr. (including family members and related entities), Berkshire Hathaway, David L. Sokol and Gregory E. Abel owned 86.2%, 9.7%, 3.5% and 0.6%, respectively, of MEHC's voting common stock and held diluted ownership interests of 15.3%, 80.5%, 2.9% and 1.3%, respectively (see Note 3).

In connection with the Teton Transaction, MEHC issued 34.6 million shares of no par, zero-coupon convertible preferred stock valued at $1,211.4 million to Berkshire Hathaway. In connection with the Kern River acquisition and the purchase of $275.0 million of The Williams Companies, Inc. (''Williams'') preferred stock, MEHC issued 6.7 million shares of no par, zero-coupon convertible preferred stock valued at $402.0 million to Berkshire Hathaway. Each share of preferred stock was convertible at the option of the holder into one share of MEHC's common stock subject to certain adjustments as described in MEHC's Amended and Restated Articles of Incorporation.

The convertible preferred stock was convertible into common stock only upon the occurrence of specified events, including modification or elimination of the Public Utility Holding Company Act of 1935 (''PUHCA 1935'') so that holding company registration would not be triggered by conversion. Additionally, the prior approval of the holders of convertible preferred stock was required for certain fundamental transactions by MEHC. Such transactions include, among others: (a) significant asset sales or dispositions; (b) merger transactions; (c) significant business acquisitions or capital expenditures; (d) issuances or repurchases of equity securities; and (e) the removal or appointment of the Chief Executive Officer.

In these notes to consolidated financial statements, references to ''U.S. dollars,'' ''dollars,'' ''$'' or ''cents'' are to the currency of the United States, references to ''pounds sterling,'' ''£,'' ''sterling,'' ''pence'' or ''p'' are to the currency of Great Britain and references to ''pesos'' are to the currency of the Philippines. References to kW means kilowatts, MW means megawatts, GW means gigawatts, kWh means kilowatt hours, MWh means megawatt hours, GWh means gigawatts hours, kV means kilovolts, MMcf means million cubic feet, Bcf means billion cubic feet, Tcf means trillion cubic feet and Dth means decatherms or one million British thermal units.

Table of Contents

2. Summary of Significant Accounting Policies

Principles of Consolidation

The consolidated financial statements include the accounts of MEHC and its wholly-owned subsidiaries, except for certain trusts formed to hold trust preferred securities which were deconsolidated under Financial Accounting Standards Board (''FASB'') Interpretation No. 46R, ''Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51'' (''FIN 46R''). Subsidiaries which are less than 100% owned but greater than 50% owned are consolidated with a minority interest. Subsidiaries that are 50% owned or less, but where the Company has the ability to exercise significant influence, are accounted for under the equity method of accounting. Investments where the Company's ability to influence is limited are accounted for under the cost method of accounting. All inter-enterprise transactions and accounts have been eliminated. The results of operations of the Company include the Company's proportionate share of results of operations of entities acquired from the date of each acquisition for purchase business combinations.

For the Company's foreign operations whose functional currency is not the U.S. dollar, the assets and liabilities are translated into U.S. dollars at current exchange rates. Resulting translation adjustments are reflected as other comprehensive income in stockholders' equity. Revenue and expenses are translated at average exchange rates for the period. Transaction gains and losses that arise from exchange rate fluctuations on transactions denominated in a currency other than the functional currency are included in the results of operations as incurred.

Reclassifications

Certain amounts in the fiscal 2004 and 2003 consolidated financial statements and supporting note disclosures have been reclassified to conform to the fiscal 2005 presentation, including the reclassifications of changes in restricted cash and investments and auction rate securities. Such reclassifications did not impact previously reported net income or retained earnings.

The accompanying consolidated statements of cash flows for the years ended December 31, 2004 and 2003 reflect a reclassification of changes in restricted cash and investments from a financing activity to an investing activity. This reclassification resulted in an increase in cash used in investing activities and a corresponding decrease in cash used in financing activities totaling $17.4 million and $68.3 million for the years ended December 31, 2004 and 2003, respectively.

The accompanying consolidated balance sheet as of December 31, 2004, reflects a reclassification of instruments used in the Company's cash management program from cash and cash equivalents to short-term investments of $123.6 million. This reclassification is to present certain auction rate securities as short-term investments rather than as cash equivalents due to the stated maturities of these investments. Additionally, in the accompanying consolidated statements of cash flows, cash and cash equivalents were reduced by $123.6 million, $72.5 million and $50.0 million at December 31, 2004, 2003 and 2002, respectively, to reflect the reclassification of these instruments from cash and cash equivalents to short-term investments.

Use of Estimates

Preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenue and expenses during the period. Management believes the most complex and sensitive judgments, because of their significance to the consolidated financial statements, result primarily from the need to make estimates about the effects of matters that are inherently uncertain. Actual results could differ materially from management's estimates.

Accounting for the Effects of Certain Types of Regulation

MidAmerican Energy, Kern River and Northern Natural Gas prepare their financial statements in accordance with the provisions of Statement of Financial Accounting Standards (''SFAS'') No. 71,

Table of Contents

''Accounting for the Effects of Certain Types of Regulation'' (''SFAS 71''), which differs in certain respects from the application of generally accepted accounting principles by non-regulated businesses. In general, SFAS 71 recognizes that accounting for rate-regulated enterprises should reflect the economic effects of regulation. As a result, a regulated entity is required to defer the recognition of costs (a regulatory asset) or the recognition of obligations (a regulatory liability) if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, MidAmerican Energy, Kern River and Northern Natural Gas have deferred certain costs and accrued certain obligations, which will be amortized over various future periods. The Company periodically evaluates the applicability of SFAS 71 and considers factors such as regulatory changes and the impact of competition. If cost-based regulation ends or competition increases, the Company may have to reduce its asset balances to reflect a market basis less than cost and write-off the associated regulatory assets and liabilities.

Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes, recent rate orders received by other regulated entities, and the status of any pending or potential deregulation legislation. Based upon this continual assessment, management believes the existing regulatory assets are probable of recovery. If future recovery of costs ceases to be probable, the asset and liability write-offs would be required to be recognized in operating income.

Revenue Recognition

Electric and Natural Gas Retail Revenues and Electric Distribution Revenues

Revenue is recorded based upon services rendered and electricity and natural gas delivered, distributed or supplied to the end of the period. MidAmerican Energy records unbilled revenue representing the estimated amounts customers will be billed between the meter reading dates in a particular month and the end of that month. The distribution businesses in Great Britain record unbilled revenue representing the estimated amounts that customers will be billed for electricity distributed during the period based upon information received from the national settlement system.

In the distribution businesses in Great Britain, revenue is not recognized when billings for electric distribution services exceed the maximum related amounts available under the regulatory formula. This over recovered amount is deducted from revenue and included in other liabilities and is available to be earned throughout the remainder of the current or future regulatory periods. Where there is an under recovered position (billings are less than the maximum related amounts available under the regulatory formula), no anticipation of any potential future recovery is made and revenue is recognized based upon the estimated billed amounts.

Natural Gas Transportation and Storage

The majority of the pipelines' transportation and storage revenues are derived from firm reservation charges which are fixed based on contractual quantities and rates. The remaining revenue, consisting primarily of commodity charges, is based on contractual rates and actual or estimated usage based on scheduled quantities and is subject to estimates including estimates of meter reading and loss and unaccounted for volumes.

Kern River and Northern Natural Gas are subject to the Federal Energy Regulatory Commission's (''FERC'') regulations and, accordingly, certain revenue collected may be subject to possible refunds upon final orders in pending rate proceedings. Kern River and Northern Natural Gas may record revenue that is subject to refund based on their best estimates of the final outcomes of these proceedings and other third party regulatory proceedings, advice of counsel and estimated total exposure, as well as collection and other risks. Estimates of any refunds are recorded in other current liabilities in the accompanying consolidated balance sheets.

Philippine Contracts

The Company invoices its customers, which consist of the Philippine National Oil Company-Energy Development Corporation (''PNOC-EDC'') for the Leyte Projects and the

Table of Contents

Philippine National Irrigation Administration (''NIA'') for the Casecnan Project, on a monthly basis for the delivery of electricity and water pursuant to the provisions of their respective project agreements. The project agreements are accounted for as arrangements that contain both an operating lease and a service contract to operate the projects. The project agreements were classified as operating leases due to significant uncertainties that existed at the inception of the leases regarding both the collection of future amounts and the amount of unreimbursable costs yet to be incurred mainly due to the existence of political, economic and other uncertainties associated with the Philippines. The Leyte Projects' primary source of revenue is from capacity fees recognized on a straight-line basis over the cooperation periods and subject to semi-annual adjustment pursuant to changes in the United States producer price index.

Additionally, for the Casecnan Project, the annual water delivery revenue is recorded on the basis of the contractual minimum guaranteed water delivery threshold for the respective contract year. If and when actual cumulative deliveries within a contract year exceed the minimum threshold, additional revenue is recognized and calculated as the product of the water deliveries in excess of the minimum threshold and the applicable unit price up to the maximum contractually allowed water delivery volume. The Company defers revenue recognition on the difference between the actual water delivery fees earned and water delivery fees invoiced pursuant to the project agreement. Revenue from electricity consists of guaranteed energy fees, recognized on a straight-line basis over the cooperation period, and a variable energy fee. The variable energy fee is recognized when deliveries of energy exceed the guaranteed energy in any contract year.

Retail 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 the closing. Loan origination and commitment fees received in connection with the origination of mortgage loans and certain direct loan origination costs are deferred until such loans are sold to investors. Fees related to brokered loan originations are recognized at closing, which is when services have been provided.

Short-term Investments

As of December 31, 2005 and 2004, the Company had $38.4 million and $123.6 million, respectively, of short-term investments consisting primarily of auction rate securities. These instruments are classified as available-for-sale securities as management does not intend to hold them to maturity nor are they bought and sold with the objective of generating profits on short-term differences in price. The carrying value of these instruments approximates their fair value.

Restricted Cash and Investments

The restricted cash and investments balance recorded separately in restricted cash and short-term investments and in deferred charges and other assets, was $136.7 million and $164.5 million at December 31, 2005 and 2004, respectively, and includes commercial paper and money market securities. The balance is mainly composed of amounts deposited in restricted accounts relating to (i) the Company's debt service reserve requirements relating to certain projects, (ii) customer deposits held in escrow, (iii) custody deposits, and (iv) unpaid dividends declared obligations. The debt service funds are restricted by their respective project debt agreements to be used only for the related project.

Investments which the Company has the positive intent and ability to hold to maturity are classified as held-to-maturity and carried at amortized cost. The carrying amount of held-to-maturity investments approximates their fair value. Investments which the Company intends to hold indefinitely, but not necessarily to maturity, are classified as available-for-sale and carried at fair value. Unrealized gains and losses on available-for-sale securities are reported as a separate component of stockholders' equity, net of deferred taxes and reclassification adjustments, except for those available-for-sale securities that comprise MidAmerican Energy's nuclear decommissioning trust funds, which are reported as an adjustment to regulatory assets or regulatory liabilities.

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 outcome of pending disputes, arbitrations and the ability of customers to pay the amounts owed to the Company. At December 31, 2005 and 2004, the allowance for doubtful accounts totaled $21.4 million and $26.0 million, respectively.

Amounts Held in Trust

Amounts held in trust consist of separately designated trust accounts for homebuyers' earnest money and other deposits. The Company holds such funds until sold properties are closed and subsequently disburses amounts in accordance with the settlement instructions. The Company does not earn or pay interest on the amounts held in trust.

Inventories

Inventories consist mainly of materials and supplies, coal stocks, gas in storage and fuel oil, which are valued at the lower of cost, determined primarily using average cost, or market.

Properties, Plants and Equipment, Net

Properties, plants and equipment are recorded at historical cost. The Company capitalizes all construction related material and direct labor costs as well as indirect construction costs. Indirect construction costs include general engineering, taxes and costs of funds used during construction. The cost of major additions and betterments are capitalized, while replacements, maintenance, and repairs that do not improve or extend the lives of the respective assets are expensed. Depreciation is generally computed using the straight-line method based on economic lives or regulatorily mandated recovery periods. The Company believes the useful lives assigned to the depreciable assets, which generally range from 3 to 67 years, are reasonable.

When the Company retires its regulated properties, plant and equipment, it charges the original cost plus the cost of retirement, less salvage value, to the cost of removal accrued regulatory liability. When it sells entire regulated, or retires or sells non-regulated, properties, plant and equipment, the original cost is removed from the property accounts and the related accumulated depreciation and amortization accounts are reduced. Any gain or loss is recorded as income, unless otherwise required by the applicable regulatory body.

The Company recognizes an asset retirement obligation (''ARO'') in accordance with SFAS No. 143, ''Accounting for Asset Retirement Obligations'' (''SFAS 143''), for legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the assets. SFAS 143 requires that the fair value of a liability for an ARO be recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. The difference between the ARO liability, the corresponding ARO net asset and amounts recovered from regulated customers to satisfy such liabilities is recorded as a regulatory asset or liability.

Impairment of Long-Lived Assets

The Company periodically evaluates long-lived assets, including properties, plants and equipment, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. Upon the occurrence of a triggering event, the carrying amount of a long-lived asset is reviewed to assess whether the recoverable amount has declined below its carrying amount. The recoverable amount is the estimated net future cash flows that the Company expects to recover from the future use of the asset, undiscounted and without interest, plus the asset's residual value on disposal. Where the recoverable amount of the long-lived asset is less than the carrying value, an impairment loss is recognized to write down the asset to its fair value that is based on discounted estimated cash flows from the future use of the asset.

Table of Contents

Goodwill

The provisions of SFAS No. 142, ''Goodwill and Other Intangible Assets'' (''SFAS 142''), which establishes the accounting for acquired goodwill and other intangible assets, and provides that goodwill and indefinite-lived intangible assets will not be amortized, requires allocating goodwill to each reporting unit and testing for impairment using a two-step approach. The goodwill impairment test is performed annually or whenever an event has occurred that would more likely than not reduce the fair value of a reporting unit below its carrying amount. The Company completed its annual review pursuant to SFAS 142 for its reporting units as of October 31, 2005 primarily using a discounted cash flow methodology. No impairment was indicated as a result of these assessments.

The Company records goodwill adjustments for (i) changes in the estimates of or the settlement of tax bases of acquired assets, liabilities and carryforwards and items relating to acquired entities' prior income tax returns, (ii) the tax benefit associated with the excess of tax-deductible goodwill over the reported amount of goodwill, and (iii) changes to the purchase price allocation prior to the end of the allocation period, which is generally one year from the acquisition date.

Deferred Financing Costs

The Company capitalizes costs associated with financings, as deferred financing costs, and amortizes the amounts over the terms of the related financings using the effective interest method.

Accruals for Loss Contingencies

The Company establishes accruals for estimated loss contingencies, such as environmental, legal and regulatory matters, when it is management's assessment that a loss is probable and the amount of the loss can be reasonably estimated. If the information available indicates that the amount of loss can only be estimated as a range of possible amounts with some amount within the range appearing to be a better estimate than any other amount within the range, that amount is accrued. If no specific amount within the range represents the most likely amount of loss, the minimum amount of the range is accrued. Accruals for loss contingencies are recorded in the period in which different facts or information become known or circumstances change that affect the previous assumptions with respect to the likelihood or amount of loss. Accruals for loss contingencies and subsequent revisions are reflected in income when accruals are recorded or as regulatory treatment dictates. Accruals for loss contingencies are based upon management's assumptions and estimates, and advice of legal counsel or other third parties regarding the probable outcomes of the matter. Should the outcomes differ from the assumptions and estimates, revisions to the estimated accruals for loss contingencies would be required.

Risk Management and Hedging Activities

The Company employs a number of different derivative and non-derivative instruments in connection with its electric and natural gas, foreign currency exchange rate and interest rate risk management activities, including forward contracts, futures, swaps and options. All derivative instruments not designated and qualifying for the normal purchases and normal sales exceptions under SFAS 133, ''Accounting for Derivative Instruments and Hedging Activities'' (''SFAS 133''), as amended, are recorded on the consolidated balance sheet at their fair values as either assets or liabilities.

For all hedge contracts, the Company provides formal documentation of the hedge in accordance with SFAS 133. In addition, at inception and on a quarterly basis the Company formally assesses whether the hedge contract is highly effective in offsetting changes in cash flows or fair values of hedged items. The Company 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 in the consolidated statement of stockholders' equity and comprehensive income as accumulated other comprehensive income (''AOCI'') until the hedged item is realized. 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 income. Gains and losses related to discontinued hedges that were previously accumulated in AOCI will remain in AOCI until the hedged item is realized, unless it is no longer probable that the hedged forecasted transaction will occur at which time associated deferred amounts in AOCI are immediately recognized in current earnings.

Certain derivative electric and gas contracts utilized by the regulated operations of MidAmerican Energy are recoverable through retail rates. Accordingly, unrealized changes in fair value of these contracts are deferred as regulatory assets or liabilities pursuant to SFAS 71.

Derivative contracts for commodities used in the Company’s 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 pursuant to the exemption provided by SFAS 133. Recognition of these contracts in revenue or cost of sales in the consolidated statement of operations occurs when the contracts settle.

When available, quoted market prices or prices obtained through external sources are used to measure a contract’s fair value. For contracts without available quoted market prices, fair value is determined based on internally developed valuation techniques or models.

Fair Value of Financial Instruments

The fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between willing parties, other than in a forced sale or liquidation. Although management uses its best judgment in estimating the fair value of these financial instruments, there are inherent limitations in any estimation technique. Therefore, the fair value estimates presented herein are not necessarily indicative of the amounts that the Company could realize in a current transaction.

The methods and assumptions used to estimate fair value are as follows:

Investments – The fair value of all investments is primarily based on quoted market prices as provided by the third-party financial institution holding the investments.

Short-term debt – Due to the short-term nature of the short-term debt, the fair value approximates the carrying value.

Debt instruments – The fair value of all debt instruments has been estimated based upon quoted market prices as supplied by third-party broker dealers, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks.

Other financial instruments – All other financial instruments of a material nature are short-term and the fair value approximates the carrying amount.

Income Taxes

MEHC and its subsidiaries file a consolidated U.S. federal income tax return and other state and federal jurisdictional returns as required. Deferred tax assets and liabilities are recognized based on the difference between the financial statement and tax basis of assets and liabilities using estimated tax rates in effect for the year in which the differences are expected to reverse. Based on existing regulatory precedent, MidAmerican Energy is not allowed to recognize state deferred income tax expense related to certain temporary differences resulting from accelerated tax depreciation and other property related basis differences. For these differences, MidAmerican Energy establishes deferred tax liabilities and regulatory assets on the consolidated balance sheets since MidAmerican Energy is allowed to recover the increased tax expense when these differences turn around. Investment tax credits have been deferred and are being amortized over the estimated useful lives of the related properties.

The Company has not provided U.S. 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. These earnings related to ongoing operations and were approximately $600 million at December 31, 2005. Because of the availability of U.S. foreign tax credits, it is not practicable to determine the U.S. 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 preparing the Company’s tax returns, management is required to interpret complex tax laws and regulations. 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. The Internal Revenue Service has closed examination of the Company’s income tax returns through 1998. Although the ultimate resolution of the Company’s tax examinations is uncertain, the Company believes it has made adequate provisions for income tax payables and the aggregate amount of any additional tax liabilities that may result from these examinations, if any, will not have a material adverse affect on the Company’s financial condition, results of operations or cash flows. Tax contingency reserves are included in accrued property and other taxes and other long-term accrued liabilities, as appropriate, in the accompanying consolidated balance sheets.

Allowance for Funds Used During Construction

Allowance for funds used during construction (‘‘AFUDC’’) represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction. Although AFUDC increases both properties, plants and equipment and earnings, it is realized in cash through depreciation provisions included in rates for MidAmerican Energy, Kern River and Northern Natural Gas, the subsidiaries that apply

SFAS 71. AFUDC for subsidiaries that apply SFAS 71 are capitalized as a component of construction in progress and will be amortized over the assets' estimated useful lives.

Other Comprehensive Income

The differences between net income and total comprehensive income for the Company are due to foreign currency translation adjustments, minimum pension liability adjustments, unrealized holding gains and losses of marketable securities during the periods, and the effective portion of net gains and losses of derivative instruments classified as cash flow hedges. Reclassification adjustments resulting from gains and losses on sales of marketable securities and cash flow hedges included in net income for the years ended December 31, 2005, 2004 and 2003 were not material.

Consolidated Statements of Cash Flows

The Company considers all investment instruments purchased with an original maturity of three months or less to be cash equivalents. Investments other than restricted cash are primarily commercial paper and money market securities. Restricted cash is not considered a cash equivalent.

The supplemental disclosures to the accompanying consolidated statements of cash flows were as follows (in thousands):

	Year Ended December 31,		
	2005	2004	2003
Interest paid, net of interest capitalized	$844,719	$855,399	$656,152
Income taxes (refunded) paid	$ 60,483	$ (16,616)	$ 9,911
Non-cash transaction – ROP note received in NIA Arbitration Settlement	$ —	$ —	$ 97,000

Table of Contents

For the year ended December 31, 2003, $170.2 million of preferred dividends of subsidiaries was not included in cash paid for interest as the Company adopted and applied the provisions of FIN 46R, related to certain finance subsidiaries, as of October 1, 2003. The adoption required the deconsolidation of certain finance subsidiaries, which resulted in amounts that were previously recorded as minority interest and preferred dividends of subsidiaries being prospectively recorded as interest expense in the accompanying consolidated statements of operations. For the years ended December 31, 2005 and 2004, and the three-month period ended December 31, 2003, the Company has recorded $184.4 million, $196.9 million and $49.8 million, respectively, of interest expense related to these securities. In accordance with the requirements of FIN 46R, no amounts prior to adoption of FIN 46R on October 1, 2003 have been reclassified.

New Accounting Pronouncements

In December 2004, the FASB issued SFAS No. 123R, ''Share-Based Payment'' (''SFAS 123R''), which replaces SFAS No. 123, ''Accounting for Stock-Based Compensation,'' and supersedes Accounting Principles Board Opinion No. 25, ''Accounting for Stock Issued to Employees.'' SFAS 123R establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services, primarily focusing on the accounting for transactions in which an entity obtains employee services in share-based payment transactions. SFAS 123R requires entities to measure compensation costs for all share-based payments, including stock options, at fair value and expense such payments over the service period. Since MEHC is considered a nonpublic entity under the criteria of SFAS 123R, this standard is effective for annual period beginning after December 15, 2005. Adoption of this standard will not have an effect on the Company's financial position, results of operations or cash flows as all of the Company's outstanding stock options were fully vested at the date of issuance of SFAS 123R. Modifications to outstanding stock options after the effective date of the standard may result in additional compensation expense pursuant to the provisions of SFAS 123R.

3. Recent Developments Involving PacifiCorp and Berkshire Hathaway

In May 2005, MEHC reached a definitive agreement with Scottish Power plc (''ScottishPower'') and its subsidiary, PacifiCorp Holdings, Inc., to acquire 100% of the common stock of ScottishPower's wholly-owned indirect subsidiary, PacifiCorp, a regulated electric utility providing service to approximately 1.6 million customers in California, Idaho, Oregon, Utah, Washington and Wyoming. MEHC will purchase all of the outstanding shares of the PacifiCorp common stock for approximately $5.1 billion in cash. The long-term debt and preferred stock of PacifiCorp, which aggregated $4.3 billion at December 31, 2005, will remain outstanding. As of March 1, 2006, all state and federal approvals required for the acquisition were obtained, subject to completion of a ''most favored states'' process in Wyoming, Washington, Utah, Idaho and Oregon that allows each such state to make applicable to that state any acquisition commitments or conditions accepted in other PacifiCorp states. Subject to the most favored states process and other customary closing conditions, the transaction is expected to close in March 2006. MEHC expects to fund the acquisition of PacifiCorp with the proceeds from an investment by Berkshire Hathaway and other existing shareholders of approximately $3.4 billion in MEHC common stock and the issuance by MEHC of $1.7 billion of either additional common stock to Berkshire Hathaway or long-term senior notes to third parties.

On February 9, 2006, following the effective date of the repeal of PUHCA 1935, Berkshire Hathaway converted its 41,263,395 shares of MEHC's no par zero-coupon convertible preferred stock into an equal number of shares of MEHC's common stock. As a consequence, Berkshire Hathaway owns 83.4% (80.5% on a diluted basis) of the outstanding common stock of MEHC, will consolidate the Company in its financial statements as a majority-owned subsidiary, and will include the Company in its consolidated federal U.S. income tax return.

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 common equity of MEHC upon any requests authorized from time to time by the Board of Directors of MEHC. 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 the Company's regulated subsidiaries. Berkshire Hathaway will have up to 180 days to fund any such request. The Berkshire Equity Commitment will expire on February 28, 2011, and will not be used for the PacifiCorp acquisition or for other future acquisitions.

On March 2, 2006, MEHC amended its Articles of Incorporation to (i) increase the amount of its common stock authorized for issuance to 115.0 million shares and (ii) no longer provide for the authorization to issue any preferred stock of MEHC.

4. Properties, Plants and Equipment, Net

Properties, plants and equipment, net comprise the following at December 31 (in thousands):

	Depreciation Life	2005	2004
Utility generation and distribution system	10-50 years	$10,499,120	$10,230,628
Interstate pipelines' assets	3-67 years	3,700,073	3,566,578
Independent power plants	10-30 years	1,384,553	1,384,660
Other assets	3-30 years	476,488	472,744
Total operating assets		16,060,234	15,654,610
Accumulated depreciation and amortization		(4,992,431)	(4,620,007)
Net operating assets		11,067,803	11,034,603
Construction in progress		847,610	572,661
Properties, plants and equipment, net		$11,915,413	$11,607,264

The utility generation and distribution system and interstate pipelines' assets are the regulated assets of MidAmerican Energy, Kern River, Northern Natural Gas and CE Electric UK. At December 31, 2005 and 2004, accumulated depreciation and amortization related to the Company's regulated assets totaled $4.1 billion and $3.8 billion, respectively. Additionally, substantially all of the construction in progress at December 31, 2005 and 2004 relates to the construction of regulated assets.

Northern Natural Gas entered into a purchase and sale agreement (''PSA'') relative to the West Hugoton non-strategic section of its interstate pipeline system in the fourth quarter of 2005. As a result of entering into the PSA, Northern Natural Gas recognized a non-cash impairment charge of $29.0 million ($17.5 million after-tax), in accordance with SFAS No. 144, ''Accounting for the Impairment of Long-Lived Assets'' (''SFAS 144''), to write down the carrying value of the West Hugoton pipeline to its fair value. The fair value was determined based on the sale price agreed to in the PSA. The impairment charge is recorded in operating expense in the accompanying consolidated statement of operations for the year ended December 31, 2005.

5. Regulatory Assets and Liabilities

The components of the Company's regulatory assets consist of the following as of December 31 (in thousands):

	As of December 31,		
	Weighted Average Remaining Life	2005	2004
Deferred income taxes, net	27 years	$173,864	$160,662
Computer systems development costs(1) (2)	6 years	54,446	63,637
Unrealized loss on regulated hedges	1 year	45,431	36,794
System levelized account(1) (2)	2 years	26,543	53,576
Pipe recoating and reconditioning costs(1)	67 years	23,256	22,406
Asset retirement obligations	8 years	20,979	20,875
Postretirement benefit costs	7 years	20,066	22,933
Debt refinancing costs	8 years	11,998	15,365
Minimum pension liability adjustment	17 years	11,694	18,203
Migration and pipeline system upgrade costs(1)	9 years	10,508	10,480
Nuclear generation assets(1)	14 years	6,487	6,727
Environmental costs	1 year	4,907	9,284
Other	Various	30,919	10,888
Total		$441,098	$451,830

(1) These regulatory assets are included in rate base and earn a return.

(2) The return earned on these regulatory assets is less than the stipulated return.

The components of the Company's regulatory liabilities, which are included in other long-term accrued liabilities in the accompanying consolidated balance sheets, consist of the following as of December 31 (in thousands):

	As of December 31,		
	Weighted Average		

	Remaining Life	2005	2004
Cost of removal accrual(1)	27 years	$448,493	$428,719
Iowa electric settlement accrual(1)	2 years	213,135	181,188
Asset retirement obligations(1)	32 years	65,966	53,259
Unrealized gain on regulated hedges	1 year	29,648	7,462
Other	Various	16,616	12,139
Total		$773,858	$682,767

(1) These regulatory liabilities are deducted from rate base or otherwise accrue a carrying cost.

Refer to Note 12 for a discussion of the cost of removal accrual and asset retirement obligations and to Note 19 regarding the Iowa electric settlement accrual.

Table of Contents

6. Other Investments

Other investments are classified as non-current in the accompanying consolidated balance sheets as management does not intend to use them in current operations. Gross unrealized gains and losses of other investments are not material at December 31, 2005 and 2004. Other investments consist of the following (in thousands):

	2005	2004
Guaranteed investment contracts	$516,330	$ —
Nuclear decommissioning trust fund	228,070	207,464
CE Generation, LLC (''CE Generation'') and Salton Sea Funding Corporation bonds	23,244	27,641
Other	31,039	26,470
Total other investments	$798,683	$261,575

In May 2005, certain indirect wholly-owned subsidiaries of CE Electric UK purchased £300.0 million of fixed rate guaranteed investment contracts (£100.0 million at 4.75% and £200.0 million at 4.73%) with a portion of the proceeds of the issuance of £350.0 million of 5.125% bonds due in 2035. These guaranteed investment contracts mature in December 2007 (£100.0 million) and February 2008 (£200.0 million), respectively, the proceeds of which will be used to repay certain long-term debt of subsidiaries of CE Electric UK. The guaranteed investment contracts are reported at cost.

MidAmerican Energy has established trusts for the investment of funds for decommissioning the Quad Cities Station. These investments in debt and equity securities are classified as available-for-sale and are reported at fair value. An amount equal to the net unrealized gains and losses on those investments is recorded as an adjustment to regulatory assets or regulatory liabilities in the accompanying consolidated balance sheets. Funds are invested in the trust in accordance with applicable federal investment guidelines and are restricted for use as reimbursement for costs of decommissioning MidAmerican Energy's Quad Cities Station. As of December 31, 2005, approximately 55.5% of the fair value of the trusts' funds was invested in domestic common equity securities, 12.3% in domestic corporate debt and the remainder in investment grade municipal and U.S. Treasury bonds. As of December 31, 2004, approximately 55.3% of the fair value of the trusts' funds was invested in domestic common equity securities, 14.4% in domestic corporate debt and the remainder in investment grade municipal and U.S. Treasury bonds.

Table of Contents

7. Equity Investments

Equity investments consist mainly of MEHC's 50% investment in CE Generation and HomeServices' equity investments in various entities that generally conduct title and mortgage activities primarily related to the real estate brokerage business. Equity investments and related equity income consist of the following (in thousands):

	As of December 31,	
	2005	2004
MEHC's investment in CE Generation	$207,794	$188,670
HomeServices' equity investments	18,739	19,047
Other	9,676	9,218
Total equity investments	$236,209	$216,935

	Year Ended December 31,		
	2005	2004	2003
MEHC's investment in CE Generation	$32,313	$ (1,542)	$17,437
HomeServices' equity investments	19,971	17,858	23,138
Other	1,029	545	(2,351)
Total equity income	$53,313	$16,861	$38,224

The following is summarized financial information for CE Generation as of and for the years ended December 31 (in thousands):

	2005	2004	2003
Operating revenue	$ 483,956	$ 439,866	$483,397

Income (loss) before cumulative effect of change in accounting principle	64,626	(3,084)	37,341
Net income (loss)	64,626	(3,084)	34,874
Current assets	151,363	127,853	
Total assets	1,418,099	1,450,507	
Current liabilities	120,888	118,623	
Long-term debt, including current portion	653,037	722,650	

CE Generation determined on December 9, 2004 that a portion of the carrying value of the Power Resources project’s long-lived assets was no longer recoverable. As a result, CE Generation recognized a non-cash impairment charge of $54.5 million ($33.5 million after-tax), in accordance with SFAS 144, to write down the long-lived assets to their fair value. The fair value was determined based on discounted estimated cash flows from the future use of the long-lived assets. The impairment charge will not result in any current or future cash expenditures. MEHC’s $16.8 million after-tax portion of the Power Resources impairment is reflected in income on equity investments in the accompanying consolidated statement of operations for the year ended December 31, 2004.

The following is summarized financial information for HomeServices’ equity investees as of and for the years ended December 31 (in thousands):

	2005	2004	2003
Revenue	$167,247	$156,959	$168,446
Operating expense	88,311	80,997	83,284
Net income	40,347	36,473	46,719
Current assets	52,749	35,957	
Total assets	134,146	170,888	
Current liabilities	44,317	27,444	
Total liabilities	101,034	137,207	

8. Short-Term Debt

Short-term debt consists of the following at December 31 (in thousands):

	2005	2004
MEHC	$51,000	$ —
CE Electric UK	10,361	38
HomeServices	8,705	9,052
Total short-term debt	$70,066	$9,090

Parent Company Revolving Credit Facilities

In the second quarter of 2005, the Company terminated its $100.0 million credit facility. On August 26, 2005, the Company closed on a new unsecured $400.0 million revolving credit facility which expires on August 26, 2010. The facility supports letters of credit for the benefit of certain subsidiaries and affiliates of which $41.9 million were outstanding at December 31, 2005. Borrowings of $51.0 million were outstanding at December 31, 2005, and no borrowings were outstanding on the prior facility at December 31, 2004. The facility carries a variable interest rate based on LIBOR or a base rate, at MEHC’s option, plus a margin. The interest rate on the balance outstanding under the facility at December 31, 2005 was 4.85%. The prior facility was not drawn on during 2004. As of December 31, 2005, MEHC was in compliance with all covenants related to its revolving credit facility.

MidAmerican Energy Revolving Credit Facilities and Short-Term Debt

As of December 31, 2005, MidAmerican Energy has in place a $425.0 million revolving credit facility expiring on November 18, 2009, which supports its $304.6 million commercial paper program and its variable rate pollution control revenue obligations. The related credit agreement requires that MidAmerican Energy’s ratio of consolidated debt to total capitalization, including current maturities, not exceed 0.65 to 1 as of the last day of any quarter. In addition, MidAmerican Energy has a $5.0 million line of credit, which expires July 1, 2006. As of December 31, 2005 and 2004, MidAmerican Energy had no commercial paper or bank notes outstanding, and the full amount of the revolving credit facility and line of credit was available. As of December 31, 2005, MidAmerican Energy was in compliance with all covenants related to its short-term borrowings. At December 31, 2005, the credit facility had a variable interest rate based on LIBOR plus 0.40% and the line of credit had a variable interest rate based on LIBOR plus 0.25%.

CE Electric UK Revolving Credit Facilities

On April 4, 2005, CE Electric UK closed on a new £100.0 million revolving credit facility which expires on April 4, 2010. The facility carries a variable interest rate based on sterling LIBOR plus a margin. Borrowings of $10.4 million were outstanding at December 31, 2005, at an interest rate of 5.14%. CE Electric UK also has a total of £35.0 million in uncommitted, variable rate, lines of credit, none of which were drawn on, at December 31, 2005.

HomeServices Revolving Credit Facilities and Short-Term Debt

HomeServices entered into a new $125.0 million senior revolving credit facility in December 2005, which expires in December 2010. This credit facility replaced the existing

$125.0 million facility, which expired in November 2005. Amounts outstanding under the new revolving credit facility are unsecured and bear interest, at HomeServices' option, at the prime lending rate or LIBOR plus a fixed spread of 0.5% to 1.125%, which varies based on HomeServices' total debt ratio. The spread was 0.5% at December 31, 2005. No borrowings were outstanding at December 31, 2005 or, under the prior facility, at December 31, 2004.

Additionally, in 2005, HomeServices has in place a mortgage warehouse line of credit totaling $25.0 million, which expires in April 2006 and bears interest at LIBOR plus a margin ranging from 1.75% to 2.00% depending on the type of mortgage loan funded. The balance outstanding on this mortgage warehouse line of credit at December 31, 2005 was $8.7 million at a weighted average interest rate of 6.14%. In 2004, HomeServices had in place two mortgage warehouse lines of credit totaling $20.0 million, which expired in 2005. The balance outstanding on these mortgage warehouse lines of credit at December 31, 2004, totaled $9.1 million at weighted average interest rates of 4.54% and 4.21%, respectively.

9. Parent Company Senior Debt

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

	Par Value	2005	2004
7.23% Senior Notes, due 2005	$ —	$ —	$ 258,797
4.625% Senior Notes, due 2007	200,000	199,622	199,403
7.63% Senior Notes, due 2007	350,000	347,354	346,000
3.50% Senior Notes, due 2008	450,000	449,638	449,497
7.52% Senior Notes, due 2008	450,000	444,539	442,828
7.52% Senior Notes, due 2008 (Series B)	100,000	100,789	101,037
5.875% Senior Notes, due 2012	500,000	499,915	499,906
5.00% Senior Notes, due 2014	250,000	249,800	249,797
8.48% Senior Notes, due 2028	475,000	484,554	484,692
Total Parent Company Senior Debt	$2,775,000	$2,776,211	$3,031,957

10. Parent Company Subordinated Debt

MEHC has organized special purpose Delaware business trusts (collectively, the ''Trusts'') pursuant to their respective amended and restated declarations of trusts (collectively, the ''Declarations'').

The financial terms of MEHC's various subordinated debentures held by such Trusts are essentially identical to the corresponding terms of the mandatorily redeemable preferred securities issued by such Trusts (the ''Trust Securities'').

Pursuant to Preferred Securities Guarantee Agreements (collectively, the ''Guarantees''), between MEHC and a trustee, MEHC has agreed irrevocably to pay to the holders of the Trust 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 Securities. MEHC owns all of the common securities of the Trusts. The CalEnergy Capital and MidAmerican Capital Trust Securities have liquidation preferences of $50 and $25 each, respectively, (plus accrued and unpaid dividends thereon to the date of payment) and represent undivided beneficial ownership interests in each of the Trusts. The assets of the Trusts consist solely of Subordinated Debentures of MEHC (collectively, the ''Junior Debentures'') issued pursuant to their respective indentures. The indentures

Table of Contents

include agreements by MEHC to pay expenses and obligations incurred by the Trusts. Considered together, the undertakings contained in the Declarations, Junior Debentures, Indentures and Guarantees constitute full and unconditional guarantees on a subordinated basis by MEHC of the Trusts' obligations under the Trust Securities.

Parent company subordinated debt consists of the following, including fair value adjustments, at December 31 (in thousands):

	Par Value	2005	2004
CalEnergy Capital Trust II – 6.25%, due 2012	$ 104,645	$ 92,724	$ 91,328
CalEnergy Capital Trust III – 6.5%, due 2027	269,980	206,175	205,253
MidAmerican Capital Trust I – 11%, due 2010	409,295	409,295	454,772
MidAmerican Capital Trust II – 11%, due 2011	600,000	600,000	700,000
MidAmerican Capital Trust III – 11%, due 2012	279,933	279,933	323,000
Total Parent Company Subordinated Debt	$1,663,853	$1,588,127	$1,774,353

Prior to the Teton Transaction, each Trust Security issued by CalEnergy Capital Trust II and III with a par value of $50 was convertible at the option of the holder at any time into shares of MEHC's common stock based on a specified conversion rate. As a result of the Teton Transaction, in lieu of shares of MEHC's common stock, upon any conversion, holders of Trust Securities will receive $35.05 for each share of common stock it would have been entitled to receive on conversion.

Distributions on the Trust Securities (and Junior Debentures) are cumulative, accrue from the date of initial issuance and are payable quarterly in arrears. The Junior Debentures are subordinated in right of payment to all senior indebtedness of the Company and the Junior Debentures are subject to certain covenants, events of default and optional and mandatory redemption provisions, all as described in the Junior Debenture indentures.

The indentures relating to the CalEnergy Trusts II and III Trust Securities give MEHC the option to defer the interest payments due on the respective Junior Debentures for up to 20 consecutive quarters during which time the corresponding distributions on the respective Trust Securities are deferred (but continue to accumulate and accrue interest). The indentures relating to the MidAmerican Capital Trust I, II and III Trust Securities give MEHC the option to defer the interest payment on the respective Junior Debentures for up to 10 consecutive semi-annual periods during which time the corresponding 11% distributions on the respective Trust Securities are deferred (but continue to accumulate and accrue interest at the rate of 13% per annum). In addition, each declaration of trust establishing the MidAmerican Capital Trusts I, II and III Trust Securities and each of the related subscription agreements contains a provision prohibiting Berkshire Hathaway and its affiliates, who are the holders of all of the respective Trust Securities issued by such Trusts, from transferring such Trust Securities to a non-affiliated person absent an event of default.

11. Subsidiary and Project Debt

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 project financing agreements, all or substantially all of the assets of each subsidiary are or may be pledged or encumbered to support or otherwise provide the security for their own project or subsidiary debt. It should not be assumed that any asset of any such subsidiary will be available to satisfy the obligations of MEHC or any of its other such subsidiaries; provided, however, that unrestricted cash or other assets which are available for distribution may, subject to applicable law and the terms of financing arrangements of such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to MEHC or affiliates thereof.

The restrictions on distributions at these separate legal entities include various covenants including, but not limited to, leverage ratios, interest coverage ratios and debt service coverage ratios. As of December 31, 2005, the separate legal entities were in compliance with all applicable covenants. However, Cordova Energy's 537 MW gas-fired power plant in the Quad Cities, Illinois area is

Table of Contents

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 and projects consists of the following, including fair value adjustments and unamortized premiums and discounts, at December 31 (in thousands):

	Par Value	2005	2004
MidAmerican Funding	$ 700,000	$ 648,390	$ 645,926
MidAmerican Energy	1,637,118	1,631,760	1,422,527
CE Electric UK	2,346,459	2,507,533	2,571,889
Kern River	1,157,256	1,157,256	1,214,808
Northern Natural Gas	800,000	799,560	799,614
CE Casecnan	142,345	140,635	194,660
Leyte Projects	42,630	42,630	105,664
Cordova Funding	198,787	196,210	203,995
HomeServices	27,788	26,313	31,438
Total Subsidiary and Project Debt	$7,052,383	$7,150,287	$7,190,521

MidAmerican Funding

The components of MidAmerican Funding's senior notes and bonds consist of the following, including fair value adjustments, at December 31 (in thousands):

	Par Value	2005	2004
6.339% Senior Notes, due 2009	$175,000	$167,903	$166,053
6.75% Senior Notes, due 2011	200,000	200,000	200,000
6.927% Senior Bonds, due 2029	325,000	280,487	279,873
Total MidAmerican Funding	$700,000	$648,390	$645,926

The subsidiaries of MidAmerican Funding must make payments on their own indebtedness before making distributions to MidAmerican Funding. The distributions are also subject to utility regulatory restrictions agreed to by MidAmerican Energy in March 1999, whereby it 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 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 equity level decreases to below 39%, even if the decrease is due to circumstances beyond the control of MidAmerican Energy.

Table of Contents

MidAmerican Energy

The components of MidAmerican Energy's mortgage bonds, pollution control revenue obligations and notes consist of the following, including unamortized premiums and discounts, at December 31 (in thousands):

	Par Value	2005	2004
Mortgage bonds, 7% Series, due 2005	$ —	$ —	$ 90,497
Pollution control revenue obligations:			

6.1% Series, due 2007	1,000	1,000	1,000
5.95% Series, due 2023, secured by general mortgage bonds	29,030	29,030	29,030
Variable rate series:			
Due 2016 and 2017, 3.59% and 2.05%	37,600	37,600	37,600
Due 2023, secured by general mortgage bonds, 3.59% and 2.05%	28,295	28,295	28,295
Due 2023, 3.59% and 2.05%	6,850	6,850	6,850
Due 2024, 3.59% and 2.05%	34,900	34,900	34,900
Due 2025, 3.59% and 2.05%	12,750	12,750	12,750
Notes:			
6.375% Series, due 2006	160,000	159,969	159,893
5.125% Series, due 2013	275,000	274,581	274,521
4.65% Series, due 2014	350,000	349,721	349,689
6.75% Series, due 2031	400,000	395,628	395,459
5.75% Series, due 2035	300,000	299,743	—
Other	1,693	1,693	2,043
Total MidAmerican Energy	$1,637,118	$1,631,760	$1,422,527

On November 1, 2005, MidAmerican Energy issued $300.0 million of 5.75% medium-term notes due in 2035. The proceeds are being used to support construction of its electric generation projects and for general corporate purposes.

CE Electric UK

The components of CE Electric UK and its subsidiaries' long-term debt consist of the following, including fair value adjustments and unamortized premiums and discounts, at December 31 (in thousands):

	Par Value	2005	2004
Variable Rate Reset Trust Securities, due 2020, 5.88%	$ —	$ —	$ 308,361
8.625% Bearer Bonds, due 2005	—	—	193,688
6.995% Senior Notes, due 2007	237,000	232,547	230,572
6.496% Yankee Bonds, due 2008	281,000	281,061	281,113
8.875% Bearer Bonds, due 2020(1)	172,110	208,912	230,215
9.25% Eurobonds, due 2020(1)	344,220	429,501	485,654
7.25% Sterling Bonds, due 2022(1)	344,220	371,457	411,287
7.25% Eurobonds, due 2028(1)	319,264	338,370	378,202
5.125% Bonds, due 2035(1)	344,220	342,528	—
5.125% Bonds, due 2035(1)	258,165	256,897	—
CE Gas Credit Facility, 6.86% and 6.36%(1)	46,260	46,260	52,797
Total CE Electric UK	$2,346,459	$2,507,533	$2,571,889

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

Table of Contents

Pursuant to a call option exercised in February 2005, at a cost of $17.5 million, a subsidiary of CE Electric UK purchased, and then cancelled, its variable rate reset trust securities, due in 2020, at a par value of £155.0 million. Accordingly, the Company included the entire principal amount of these securities in its current portion of long-term debt in the accompanying consolidated balance sheet at December 31, 2004.

On May 5, 2005, Northern Electric Finance plc, an indirect wholly-owned subsidiary of CE Electric UK, issued £150.0 million of 5.125% bonds due 2035, guaranteed by Northern Electric and guaranteed as to scheduled payments of principal and interest by Ambac Assurance UK Limited (''Ambac''). Additionally, on May 5, 2005, Yorkshire Electricity, an indirect wholly-owned subsidiary of CE Electric UK, issued £200.0 million of 5.125% bonds due 2035, guaranteed as to scheduled payments of principal and interest by Ambac. The proceeds from the offerings are being invested and used for general corporate purposes. Investments include a £100.0 million 4.75% fixed rate guaranteed investment contract maturing December 2007 and a £200.0 million 4.73% fixed rate guaranteed investment contract maturing February 2008.

Kern River

The components of Kern River's term notes consist of the following at December 31 (in thousands):

	Par Value	2005	2004
6.676% Senior Notes, due 2016	$ 415,167	$ 415,167	$ 439,000
4.893% Senior Notes, due 2018	742,089	742,089	775,808
Total Kern River	$1,157,256	$1,157,256	$1,214,808

Northern Natural Gas

The components of Northern Natural Gas' senior notes consist of the following, including unamortized premiums and discounts, at December 31 (in thousands):

	Par Value	2005	2004
6.875% Senior Notes, due 2005	$ —	$ —	$ 99,963
6.75% Senior Notes, due 2008	150,000	150,000	150,000
7.00% Senior Notes, due 2011	250,000	250,000	250,000
5.375% Senior Notes, due 2012	300,000	299,688	299,651
5.125% Senior Notes, due 2015	100,000	99,872	—
Total Northern Natural Gas	$800,000	$799,560	$799,614

On April 14, 2005, Northern Natural Gas issued $100.0 million of 5.125% senior notes due May 1, 2015. The proceeds were used by Northern Natural Gas to repay its outstanding $100.0 million 6.875% senior notes due May 1, 2005.

CE Casecnan

CE Casecnan Water and Energy Company, Inc.'s (''CE Casecnan'') term notes and bonds consist of the following, including fair value adjustments, at December 31 (in thousands):

	Par Value	2005	2004
11.45% Senior Secured Series A Notes, due in 2005	$ —	$ —	$ 47,432
11.95% Senior Secured Series B Bonds, due in 2010	142,345	140,635	147,228
Total CE Casecnan	$142,345	$140,635	$194,660

Table of Contents

Leyte Projects

The Leyte Projects' term loans consist of the following at December 31 (in thousands):

	Par Value	2005	2004
Mahanagdong Project 6.92% Term Loan, due 2007	$30,922	$30,922	$ 51,537
Mahanagdong Project 7.60% Term Loan, due 2007	6,857	6,857	11,428
Malitbog Project 4.99% and 3.67%, due 2005	—	—	11,866
Malitbog Project 9.176% Term Loan, due 2005	—	—	6,580
Upper Mahiao Project 5.95% Term Loan, due 2006	4,851	4,851	24,253
Total Leyte Projects	$42,630	$42,630	$105,664

MEHC provides debt service reserve letters of credit in amounts equal to the next semi-annual principal and interest payments due on the loans which were equal to $18.8 million and $44.6 million at December 31, 2005 and 2004, respectively.

Cordova Funding

Cordova Funding Corporation's (''Cordova Funding'') senior secured bonds are due in semi-annual installments and consist of the following, including fair value adjustments, at December 31 (in thousands):

	Par Value	2005	2004
8.48% Senior Secured Bonds, due 2019	$ 11,269	$ 11,269	$ 11,716
8.64% Senior Secured Bonds, due 2019	82,620	80,457	83,655
8.79% Senior Secured Bonds, due 2019	27,661	27,247	28,328
8.82% Senior Secured Bonds, due 2019	51,350	51,350	53,384
9.07% Senior Secured Bonds, due 2019	25,887	25,887	26,912
Total Cordova Funding	$198,787	$196,210	$203,995

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 $37.0 million. MEHC has also issued a debt service reserve guarantee, the maximum amount of which is equal at any given time to the difference between the next succeeding debt service payment ($11.0 million as of December 31, 2005) and the amount then on deposit in the debt service reserve fund ($9.0 million at December 31, 2005).

As of December 31, 2005, Cordova Funding is currently prohibited from making distributions by the terms of its indenture due to its failure to meet its debt service coverage ratio requirement.

HomeServices

The components of HomeServices' long-term debt consist of the following, including fair value adjustments, at December 31 (in thousands):

	Par Value	2005	2004
7.12% Senior Notes, due 2010	$25,000	$23,525	$28,475
Other	2,788	2,788	2,963
Total HomeServices	$27,788	$26,313	$31,438

Annual Repayments of Long-Term Debt

The annual repayments of parent company and subsidiary and project debt for the years beginning January 1, 2006 and thereafter, excluding fair value adjustments and unamortized premiums and discounts, are as follows (in thousands):

Table of Contents

	2006	2007	2008	2009	2010	Thereafter	Total
Parent company senior debt	$ —	$ 550,000	$1,000,000	$ —	$ —	$1,225,000	$ 2,775,000

Parent company subordinated debt	234,021	234,021	234,021	234,021	188,543	539,226	1,663,853
MidAmerican Funding	—	—	—	175,000	—	525,000	700,000
MidAmerican Energy	160,509	1,651	448	32	32	1,474,446	1,637,118
CE Electric UK	5,190	251,481	291,326	8,208	5,763	1,784,491	2,346,459
Kern River	71,360	69,472	72,816	74,906	78,668	790,034	1,157,256
Northern Natural Gas	—	—	150,000	—	—	650,000	800,000
CE Casecnan	36,015	37,730	37,730	13,720	17,150	—	142,345
Leyte Projects	30,037	12,593	—	—	—	—	42,630
Cordova Funding	4,500	4,163	4,725	6,412	9,000	169,987	198,787
HomeServices	6,050	5,855	5,409	5,156	5,152	166	27,788
Totals	$547,682	$1,166,966	$1,796,475	$517,455	$304,308	$7,158,350	$11,491,236

Fair Value

At December 31, 2005, the Company had fixed-rate long-term debt of $11,348.0 million in principal amount and having a fair value of $12,066.0 million. In addition, at December 31, 2005, the Company had floating-rate obligations of $166.7 million that expose the Company to the risk of increased interest expense in the event of increases in short-term interest rates. The fair value of the floating-rate obligations and the short-term debt approximates their carrying amounts.

At December 31, 2004, the Company had fixed-rate long-term debt of $11,503.4 million in principal amount and having a fair value of $12,416.2 million. In addition, at December 31, 2004, the Company had floating-rate obligations of $493.4 million. The fair value of the floating-rate obligations and the short-term debt approximates their carrying amounts.

12. Asset Retirement Obligations

On December 31, 2005, the Company adopted FASB Interpretation No. 47, ''Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143'' (''FIN 47''). FIN 47 clarifies that the term *conditional asset retirement obligation* as used in SFAS 143 refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Accordingly, the Company is required to recognize a liability for the fair value of a conditional ARO if the fair value of the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO should be factored into the measurement of the liability when sufficient information exists.

In conjunction with the adoption of FIN 47, the Company recorded $11.4 million of ARO liabilities; $0.8 million of associated ARO assets, net of accumulated depreciation; and a $10.6 million reduction of regulatory liabilities. Adoption of FIN 47 did not impact net income.

The change in the balance of the ARO liability, which is included in other long-term accrued liabilities in the accompanying consolidated balance sheets, for the years ended December 31 is summarized as follows (in thousands):

	2005	2004
Balance, January 1	$185,781	$ 284,377
Adoption of FIN 47	11,422	—
Revisions	1,120	(120,098)
Additions	3,897	5,602
Retirements	(4,331)	—
Accretion	10,659	15,900
Balance, December 31	$208,548	$ 185,781

Table of Contents

At December 31, 2005, $163.0 million of the total ARO liability pertained to the decommissioning of Quad Cities Station. Assets of $228.1 million, reflected in other investments in the accompanying consolidated balance sheet, are restricted for satisfying the Quad Cities Station ARO liability.

Revisions for the year ended December 31, 2004 include a revision to the nuclear decommissioning ARO liability as a result of a change in the assumed life of Quad Cities Station pursuant to a 20-year extension to the operating license of the plant by the NRC in October 2004 and its impact on the timing of related cash flows.

The total ARO liability, computed on a pro forma basis as if FIN 47 had been applied during each of the periods presented in the consolidated financial statements, would have been as follows (in millions):

As of January 1, 2003	$300.4
As of December 31, 2003	295.2
As of December 31, 2004	197.0

In addition to the ARO liabilities, MidAmerican Energy has accrued for the cost of removing other electric and natural gas assets through its depreciation rates, in accordance with accepted regulatory practices. These accruals, totaling $448.5 million and $428.7 million at December 31, 2005 and 2004, respectively, are reflected as regulatory liabilities and included in other long-term accrued liabilities in the accompanying consolidated balance sheets.

13. Preferred Securities of Subsidiaries

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 $31.1 million. The aggregate total the holders of all preferred securities outstanding at December 31, 2005, are entitled to upon involuntary bankruptcy is $30.3 million plus accrued dividends. The total annual dividend requirements for all preferred securities outstanding at December 31, 2005 were $1.2 million.

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 $56.0 million as of December 31, 2005 and 2004, respectively.

14. Risk Management and Hedging Activities

The Company is directly exposed to the impact of market fluctuations in the prices of natural gas and electricity as a result of its ownership of MidAmerican Energy, Northern Natural Gas and CE Electric UK. Exposure to foreign currency risk exists from investment in businesses, primarily CE Electric UK, operated in foreign countries. The Company is exposed to interest rate risk as a result of the issuance of fixed rate debt. The Company employs established policies and procedures to manage its risks associated with these market fluctuations using various commodity and financial derivative instruments, including forward contracts, futures, swaps and options. The risk management process established by each business platform is designed to identify, assess, monitor, report, manage, and mitigate each of the various types of risk involved in its business. The Company does not engage in a material amount of proprietary trading activities.

Table of Contents

As of December 31, 2005, the Company held derivative instruments with the following fair values (in millions):

	Commodity					
	MidAmerican Energy	Northern Natural Gas	Other	Foreign Exchange Swaps	Interest Rate Locks	Total
Maturity:						
2006	$ (9.0)	$ 1.2	$ (6.0)	$ —	$ —	$ (13.8)
2007 – 2009	(5.2)	(6.7)	(4.8)	(77.5)	—	(94.2)
After 2009	—	(0.6)	—	—	—	(0.6)
Total	$ (14.2)	$ (6.1)	$(10.8)	$ (77.5)	$ —	$(108.6)

Commodity Cash Flow Hedges

Some of MEHC's subsidiaries are exposed to market price fluctuations of various commodities related to their ongoing power generation and natural gas gathering, distribution, processing and marketing activities. The Company closely monitors the potential impacts of commodity price changes and, where appropriate, enters into contracts to lock-in prices for a portion of the future sales, generation revenue and fuel expenses.

Certain derivative electric and gas contracts utilized by the regulated operations of MidAmerican Energy are recoverable through retail rates. Accordingly, unrealized changes in fair value of these contracts are deferred as regulatory assets or liabilities pursuant to SFAS 71. At December 31, 2005, $32.7 million of derivative assets and $47.6 million of derivative liabilities were used for regulated purposes.

Other MEHC subsidiaries use derivative instruments such as swaps, futures, forwards and options as cash flow hedges for natural gas and other transactions.

Currency Exchange Rate Risk

CE Electric UK has entered into certain currency rate swap agreements for its senior notes and Yankee bonds with large multi-national financial institutions. The swap agreements effectively convert the U.S. dollar fixed interest rate to a fixed rate in sterling for $237.0 million of 6.995% senior notes and $281.0 million of 6.496% Yankee bonds outstanding at December 31, 2005. The agreements extend until December 30, 2007 and February 25, 2008, respectively. The estimated fair value of these swap agreements at December 31, 2005 and 2004, was $77.5 million and $131.8 million, respectively, based on quotes from the counterparties to these instruments and represents the estimated amount that the Company would expect to pay if these agreements were terminated.

Interest Rate Hedges

The Company may enter into contractual agreements to hedge exposure to interest rate risk. Changes in fair value of interest rate ''locks'' used as cash flow hedges are reported in accumulated other comprehensive income to the extent the hedge is effective until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense over the term of the related debt issuance. In May 2005, MEHC entered into a treasury rate lock agreement in the notional amount of $1.6 billion to protect against a rise in interest rates related to the anticipated financing of the PacifiCorp acquisition. For the year ended December 31, 2005, the amount of the deferred gain included in other comprehensive income was $ – million.

Credit Risk

Domestic Regulated Operations

MidAmerican Energy's utility operations grant unsecured credit to its retail electric and gas customers, substantially all of whom are local businesses and residents, which totaled $186.0 million at December 31, 2005. MidAmerican Energy also extends unsecured credit to other utilities, energy

Table of Contents

marketers, financial institutions and certain commercial and industrial end-users in conjunction with wholesale energy marketing activities. MidAmerican Energy analyzes the financial condition of each significant counterparty before entering into any transactions, establishes limits on the amount of unsecured credit to be extended to each counterparty, and evaluates the appropriateness of unsecured credit limits on a daily basis. MidAmerican Energy seeks to negotiate contractual arrangements with wholesale counterparties to provide for net settlement of monthly accounts receivable and accounts payable and net settlement of contracts for future performance in the event of default. At December 31, 2005, 84.4% of MidAmerican Energy's credit exposure, net of collateral, from wholesale operations was with counterparties having ''investment grade'' credit ratings from Moody's or Standard & Poor's, while an additional 7.4% of MidAmerican Energy's credit exposure, net of collateral, from wholesale operations was with counterparties having financial characteristics deemed equivalent to ''investment grade'' by MidAmerican Energy based on internal review.

Northern Natural Gas' primary customers include regulated local distribution companies in the upper Midwest. Kern River's primary customers are electric generating companies and energy marketing and trading companies in the western United States. 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 an industry standard ''Distribution Use of System Agreement,'' which Northern Electric and Yorkshire Electricity separately entered into with the various suppliers of electricity in their respective distribution service areas. 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 44% of distribution revenues in 2005. The Office of Gas and Electricity Markets (''Ofgem'') has determined a framework which sets credit limits for each supply business 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 cover must be 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

PNOC-EDC's and NIA's obligations under the project agreements are the Leyte Projects' and Casecnan Project'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 agreements 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 CalEnergy Generation-Foreign was $312.3 million for the year ended December 31, 2005. The Leyte Projects' agreements expire in June 2006 and July 2007, respectively, while the Casecnan Project's agreement expires in December 2021.

Table of Contents

15. Income Taxes

Income tax expense on continuing operations consists of the following (in thousands):

	Year Ended December 31,		
	2005	**2004**	**2003**
Current:			
Federal	$ 35,535	$ 18,794	$ (48,911)
State	5,366	(9,862)	10,901
Foreign	73,844	79,463	88,150
	114,745	88,395	50,140
Deferred:			
Federal	52,944	112,719	141,795
State	9,959	607	10,833
Foreign	67,061	63,265	67,508
	129,964	176,591	220,136
Total	$244,709	$264,986	$270,276

A reconciliation of the federal statutory tax rate to the effective tax rate on continuing operations applicable to income before income tax expense follows:

	2005	**2004**	**2003**
Federal statutory rate	35.0%	35.0%	35.0%
General business tax credits	(2.0)	(0.6)	(0.5)
State taxes, net of federal tax effect	1.5	2.2	1.8
Equity income	2.4	0.7	1.6
Dividends on preferred securities of subsidiaries	—	—	(6.9)
Tax effect of foreign income	(2.0)	0.3	0.5
Dividends received deduction	(1.3)	—	(1.1)
Effects of ratemaking	(0.8)	(0.9)	0.9
Other items, net	(0.8)	(3.5)	0.2
Effective tax rate	32.0%	33.2%	31.5%

The net deferred tax liability consists of the following at December 31 (in thousands):

	2005	2004
Deferred tax assets:		
Minimum pension liability adjustment	$ 145,767	$ 163,761
Revenue sharing accruals	92,040	80,220
Accruals not currently deductible for tax purposes	80,798	54,402
Deferred income	20,050	34,458
Nuclear reserve and decommissioning	14,962	27,112
Net operating loss (''NOL'') and credit carryforwards	265,408	267,051
Other	4,551	16,569
Total deferred tax assets	623,576	643,573
Deferred tax liabilities:		
Properties, plants and equipment, net	1,756,340	1,700,884
Income taxes recoverable through future rates	176,108	163,108
Employee benefits	40,632	51,509
Fuel cost recoveries	9,897	6,028
Reacquired debt	2,473	3,877
Total deferred tax liabilities	1,985,450	1,925,406
Net deferred tax liability	$1,361,874	$1,281,833

At December 31, 2005, the Company has available unused NOL and credit carryforwards that may be applied against future taxable income and that expire at various intervals between 2007 and 2026.

16. Other Income and Expense

Other income for the years ending December 31 consists of the following (in thousands):

	2005	2004	2003
Allowance for equity funds used during construction	$26,170	$ 20,476	$26,708
Gains on sales of non-strategic assets and investments	23,298	3,609	4,183
Gains on Enron note receivable and other claims	6,358	72,210	—
Corporate-owned life insurance income	5,150	5,447	6,317
Gain on Mirant bankruptcy claim	—	14,750	—
Gain on CE Casecnan settlement	—	—	31,889
Gain on Williams preferred stock	—	—	13,750
Other	13,540	11,713	13,796
Total other income	$74,516	$128,205	$96,643

Non-Strategic Assets and Investments

Included in gains on sales of non-strategic assets and investments for the year ended December 31, 2005, are gains from sales of certain non-strategic, passive investments at MidAmerican Funding of $13.4 million and CE Electric UK of $8.4 million.

Enron Note Receivable and Other Claims

Northern Natural Gas had a note receivable of approximately $259.0 million (the ''Enron Note Receivable'') with Enron. As a result of Enron filing for bankruptcy on December 2, 2001, Northern Natural Gas filed a bankruptcy claim against Enron seeking to recover payment of the Enron Note

Receivable. As of December 31, 2001, Northern Natural Gas had written-off the note. By stipulation, Enron and Northern Natural Gas agreed to a value of $249.0 million for the claim and received approval of the stipulation from Enron's Bankruptcy Court on August 26, 2004. On November 23, 2004, Northern Natural Gas sold its stipulated general, unsecured claim against Enron of $249.0 million to a third party investor for $72.2 million.

Mirant Americas Energy Marketing (''Mirant'') Claim

Mirant was one of the shippers that entered into a 15-year, 2003 Expansion Project, firm gas transportation contract (90,000 Dth per day) with Kern River and provided a letter of credit equivalent to 12 months of reservation charges as security for its obligations thereunder. In July 2003, Mirant filed for Chapter 11 bankruptcy protection and Kern River subsequently drew on the letter of credit and held the proceeds thereof, $14.8 million, as cash collateral. The bankruptcy court ultimately determined that Kern River was entitled to the $14.8 million cash collateral which resulted in Kern River recognizing such amount as other income.

CE Casecnan Arbitration Settlement

On October 15, 2003, CE Casecnan, an indirect, majority-owned subsidiary of the Company, closed a transaction settling the arbitration, which arose from a Statement of Claim made on August 19, 2002, by CE Casecnan against the Republic of the Philippines (''ROP'') NIA. As a result of the agreement, CE Casecnan recorded $31.9 million of other income and $24.4 million of associated income taxes. In connection with the settlement, the NIA delivered to CE Casecnan a $97.0 million 8.375% ROP Note due 2013 (the ''ROP

Note''), which contained a put provision granting CE Casecnan the right to put the ROP Note to the ROP for a price of par plus accrued interest for a 30-day period commencing on January 14, 2004. On January 14, 2004, CE Casecnan exercised its right to put the ROP Note to the ROP and, in accordance with the terms of the put, CE Casecnan received $99.2 million (representing $97.0 million par value plus accrued interest) from the ROP on January 21, 2004.

Williams Preferred Stock

On March 27, 2002, the Company invested $275.0 million in Williams in exchange for shares of 9.875% cumulative convertible preferred stock of Williams. Dividends on the Williams preferred stock were received quarterly, commencing July 1, 2002. On June 10, 2003, Williams repurchased, for $288.8 million, plus accrued dividends, all of the shares of its 9.875% Cumulative Convertible Preferred Stock originally acquired by the Company in March 2002 for $275.0 million. The Company recorded a pre-tax gain of $13.8 million on the transaction.

Other Expense

The Company's other expense totaled $22.1 million, $10.1 million and $5.9 million, respectively, for the years ended December 31, 2005, 2004 and 2003. MidAmerican Funding has investments in commercial passenger aircraft leased to major domestic airlines, which are accounted for as leveraged leases. During 2005, the airline industry continued to deteriorate and two major airline carriers filed for bankruptcy. MidAmerican Funding evaluated its investments in commercial passenger aircraft and recognized losses totaling $15.6 million for other-than-temporary impairments of those investments.

17. Discontinued Operations – Zinc Recovery Project and Mineral Assets

Indirect wholly-owned subsidiaries of MEHC own the rights to commercial quantities of extractable minerals from elements in solution in the geothermal brine and fluids utilized at certain geothermal energy generation facilities located in the Imperial Valley of California and a zinc recovery plant constructed near the geothermal energy generation facilities designed to recover zinc from the geothermal brine through an ion exchange, solvent extraction, electrowinning and casting process (the ''Zinc Recovery Project'').

The Zinc Recovery Project began limited production during December 2002 and continued limited production until September 10, 2004. On September 10, 2004, management made the decision to cease operations of the Zinc Recovery Project. Based on this decision, a non-cash, after-tax impairment charge of $340.3 million was recorded to write-off the Zinc Recovery Project, rights to quantities of extractable minerals, and allocated goodwill (collectively, the ''Mineral Assets''). The charge and the related activity of the Mineral Assets are classified separately as discontinued operations in the accompanying consolidated statements of operations and include the following (in thousands):

	Year Ended December 31.		
	2005	2004	2003
Operating revenue	$ —	$ 3,401	$ 659
Losses from discontinued operations	$ —	$ (42,695)	$(46,423)
Proceeds from (costs of) disposal activities, net	7,634	(4,134)	—
Asset impairment charges	—	(479,233)	—
Goodwill impairment charges	—	(52,776)	—
Income tax (expense) benefit	(2,500)	211,277	19,305
Income (loss) from discontinued operations, net of tax	$ 5,134	$(367,561)	$(27,118)

In connection with ceasing operations, the Zinc Recovery Project's assets have been dismantled and sold and certain employees of the operator of the Zinc Recovery Project were paid one-time termination benefits. Implementation of the decommissioning plan began in September 2004 and, as of December 31, 2005, the dismantling, decommissioning, and sale of remaining assets of the Zinc Recovery Project was completed. Proceeds from the sale of the Zinc Recovery Project's assets exceeded the cost of disposal activities during the year ended December 31, 2005. Salvage proceeds were recognized in the period earned. Costs were recognized in the period in which the related liability was incurred. Cash expenditures of approximately $4.1 million, consisting of pre-tax disposal costs, termination benefit costs and property taxes, were made through December 31, 2004.

18. Stock Transactions

On January 6, 2004, the Company purchased a portion of the shares of common stock owned by Mr. Sokol for an aggregate purchase price of $20.0 million.

There were no common stock options granted, forfeited or allowed to expire during each of the three years in the period ended December 31, 2005. Common stock options exercised during each of the three years in the period ended December 31, 2005 consisted solely of 200,000 in 2005 held by Mr. Sokol having an exercise price of $29.01 per share. There were 1,848,329 common stock options outstanding and exercisable with a weighted-average exercise price of $30.75 per share at December 31, 2005. 1,145,000 of the outstanding and exercisable common stock options have exercise prices ranging from $15.94 to $34.69 per share, a weighted-average exercise price of $28.11 per share and a remaining contractual life of 2.25 years. The remaining 703,329 outstanding and exercisable common stock options have an exercise price of $35.05 per share and a remaining contractual life of 4.25 years. There were 2,048,329 common stock options outstanding and exercisable with a weighted-average exercise price of $30.58 per share at December 31, 2004, 2003 and 2002.

19. Regulatory Matters

MidAmerican Energy

Under a series of settlement agreements between MidAmerican Energy, the Iowa Office of Consumer Advocate (''OCA'') and other interveners approved by the IUB, MidAmerican Energy has agreed not to seek a general increase in electric rates to become effective prior to January 1, 2012 unless its Iowa jurisdictional electric return on equity for any year falls below 10%. 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 such rates. As a party to the settlement agreements, the OCA has agreed not to seek any decrease in MidAmerican Energy's Iowa electric rates prior to January 1, 2012. 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 revenues for MidAmerican Energy. The settlement agreements also each provide that portions of revenues associated with Iowa retail electric returns on equity within specified ranges will be recorded as a regulatory liability.

Under a settlement agreement approved by the IUB on December 31, 2001, which was effective through December 31, 2005, an amount equal to 50% of revenues associated with returns on equity between 12% and 14%, and 83.33% of revenues associated with returns on equity above 14%, in each year was recorded as a regulatory liability. A settlement agreement, which was filed in conjunction with MidAmerican Energy's application for ratemaking principles on its 2004/2005 wind power project and approved by the IUB on October 17, 2003, provided that during the period January 1, 2006 through December 31, 2010, an amount equal to 40% of revenues associated with returns on equity between 11.75% and 13%, 50% of revenues associated with returns on equity between 13% and 14%, and 83.3% of revenues associated with returns on equity above 14%, in each year will be recorded as a regulatory liability.

A settlement agreement approved by the IUB on January 31, 2005, in conjunction with MidAmerican Energy's 2005 expansion of its wind power project extended through 2011 MidAmerican Energy's commitment not to seek a general increase in electric rates unless its Iowa jurisdictional electric return on equity falls below 10%. It also extended the revenue sharing mechanism through 2011, and the OCA agreed not to seek any decrease in Iowa electric base rates to become effective before January 1, 2012.

On December 16, 2005, MidAmerican Energy filed with the IUB a settlement agreement between MidAmerican Energy and the OCA regarding ratemaking principles for up to 545 MW of additional wind generation capacity in Iowa, based on nameplate ratings. The settlement agreement, which is subject to IUB approval, extends through 2012 MidAmerican Energy's commitment not to seek a general increase in electric rates unless its Iowa jurisdictional electric return on equity for the calendar year 2011 falls below 10%. Additionally, the revenue sharing mechanism is extended through 2012, and the OCA agrees not to seek any decrease in Iowa electric base rates to become effective prior to January 1, 2013.

The regulatory liabilities created by the settlement agreements are recorded as a regulatory charge in depreciation and amortization expense when the liability is accrued. Additionally, interest expense is accrued on the portion of the regulatory liability balance recorded in prior years. The regulatory liabilities created for the years through 2010 are expected to be reduced as they are credited against plant in service associated with generating plant additions. As a result of the credit applied to generating plant balances from the reduction of the regulatory liabilities, future depreciation will be reduced. The regulatory liability accrued for 2011 and 2012, if any, will be credited to customer bills in 2012 and 2013, respectively.

Kern River

Kern River's tariff rates are designed to give it an opportunity to recover all actually and prudently incurred operations and maintenance costs of its pipeline system, taxes, interest, depreciation and amortization and a regulated equity return. 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; however, rate design is the subject of Kern River's current rate case before the FERC and may be subject to change as a result of the rate case outcome. This levelized cost of service has been achieved by using a FERC-approved depreciation schedule in which depreciation increases as interest expense decreases. If the Kern River system is converted to a traditional rate design as a result of the 2004 general rate case, the depreciation of Kern River's transmission system would be calculated on a

straight-line basis over the expected economic life of its facilities. Under the traditional methodology, transportation rates do not remain constant over the lives of the shipper contracts, but rather are adjusted in each rate case to reflect current operating costs, updated depreciation rates and the rate base investment then in effect.

Kern River was required to file its 2004 general rate case no later than May 1, 2004 pursuant to the terms of its 1998 FERC Docket No. RP99-274 rate case settlement. Kern River filed its rate case on April 30, 2004, which supports an annual revenue increase of $40.1 million representing a 13% increase from its existing cost of service and a proposed overall cost of service of $347.4 million. The rate increase became effective on November 1, 2004, subject to refund. Since its previous rate case, Kern River increased the capacity of its system from 724,500 Dth per day to 1,755,575 Dth per day at a cost of approximately $1.2 billion. The filing employed the levelized rate methodology.

The Kern River 2004 general rate case hearing concluded in August 2005. On March 2, 2006, Kern River received an initial decision on the case from the administrative law judge. Briefs on exceptions will be due on April 3, 2006, and briefs opposing exceptions are due April 26, 2006. The administrative law judge's initial decision is non-binding and after briefing, the FERC will issue its initial decision on the case. The initial FERC decision, which may result in rate refunds, typically becomes binding on all parties while rehearing requests on the FERC decision and/or court appeals are pending. The initial FERC decision is not expected until late 2006 or early 2007. The final resolution of the rate case is dependent on receiving a final, non-appealable decision on the case from the FERC, or approval of a settlement of the case by the FERC.

Northern Natural Gas

Northern Natural Gas continues to use a straight fixed variable rate design which provides that all fixed costs assignable to firm capacity customers, including a return on equity, are to be recovered through fixed monthly demand or capacity reservation charges which are not a function of throughput volumes.

On May 1, 2003, Northern Natural Gas filed a general rate case proceeding for increased rates with the FERC and filed an additional rate case proceeding on January 30, 2004 to reflect further cost increases. The FERC consolidated the 2003 and 2004 rate cases due to the similarity of issues in both cases and the updated costs. On March 25, 2005, as modified on April 22, 2005, Northern Natural Gas filed a stipulation and agreement with the FERC (the ''Settlement'') resolving the consolidated rate cases. On June 20, 2005, the FERC approved the Settlement without modification. The Settlement represents the agreement Northern Natural Gas reached with its customers to settle the base tariff rates and related tariff issues in the consolidated cases. The Settlement provided for, among other things, rates designed to generate revenues on an annual basis above the base rates which were in effect as of October 31, 2003, as follows: $48 million for the period November 1, 2003 through October 31, 2004, $53 million for the period November 1, 2004 through October 31, 2005, $58 million for the period November 1, 2005 through October 31, 2006, and $62 million beginning November 1, 2006. Northern Natural Gas provided refunds including interest of $71.5 million to its customers in the third quarter of 2005 consistent with the terms of the Settlement, generally reflecting the difference between the rate increases implemented on November 1, 2003 and November 1, 2004 and the revenue generated using the Settlement rates.

In April 2004, Northern Natural Gas also filed tariff sheets with the FERC in relation to its system levelized account (''SLA'') (an imbalance recovery mechanism) with the new rates going into effect on June 1, 2004, subject to refund. On February 14, 2005, Northern Natural Gas received FERC approval of the SLA settlement. The SLA settlement provides for recovery of the final SLA balance as of December 31, 2004, over a forty-eight month period beginning November 1, 2003. Under the SLA settlement, Northern Natural Gas is responsible for the financial impacts of managing operational storage volumes.

CE Electric UK

Most of the revenue of the DLHs in Great Britain is controlled by a distribution price control formula which is set out in the license of each DLH. It has been the practice of Ofgem (and its

Table of Contents

predecessor body, the Office of Electricity Regulation), to review and reset the formula at five-year intervals, although the formula has been, and may be, further reviewed at other times at the discretion of the regulator. Any such resetting of the formula requires the consent of the DLH. If the DLH does not consent to the formula reset, it is reviewed by the British competition commission, whose recommendations can then be given effect by license modifications made by Ofgem.

The current formula requires that regulated distribution income per unit is increased or decreased each year by RPI-Xd where RPI means the Retail Prices Index, reflecting the average of the 12-month inflation rates recorded for each month in the previous July to December period. The Xd factor in the formula was established by Ofgem at the price control review effective in April 2005 (and through March 31, 2010, is expected to continue to be set) at 0%. The formula also takes account of a variety of other factors including the changes in system electrical losses, the number of customers connected and the voltage at which customers receive the units of electricity distributed. The distribution price control formula determines the maximum average price per unit of electricity distributed (in pence per kWh) which a DLH is entitled to charge. The distribution price control formula permits DLHs to receive additional revenue due to increased distribution of units and the increase in the number of end users. The price control does not seek to constrain the profits of a DLH from year to year. It is a control on revenue that operates independently of most of the DLH's costs. During the term of the price control, cost savings or additional costs have a direct impact on income and cash flow.

The procedure and methodology adopted at a price control review are at the reasonable discretion of Ofgem. Generally, Ofgem's judgment of the future allowed revenue of licensees has been based upon, among other things:

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

As a result of the review concluded in 2004, the allowed revenue of Northern Electric's distribution business was reduced by 4%, in real terms, and the allowed revenue of Yorkshire Electricity's distribution business was reduced by 9%, in real terms, with effect from April 1, 2005. Ofgem indicated that during the period 2005 to 2010, the retention of the benefits of any out-performance from the operating cost assumptions made by Ofgem in setting the new price control might depend on the successful implementation of revised cost reporting guidelines prescribed by Ofgem and to be applied by all DLHs.

The triennial process of valuing the UK pension plan's assets and liabilities, which valued the plan assets and liabilities as of March 31, 2004, was completed in 2005. This valuation set a revised level of contributions for the next three years. The report of the actuaries conducting the valuation showed a funding deficiency of £190.3 million. Based on this valuation, CE Electric UK will contribute £23.1 million to the pension plan each year in respect of the existing funding deficiency. The amount in respect of the funding deficiency has been calculated based on eliminating the funding deficiency over 12 years commencing April 1, 2005. In setting the allowed revenue of Northern Electric and Yorkshire Electricity (and all other DLHs) with effect from April 1, 2005, Ofgem made a specific allowance for an amount in respect of each DLH's pension costs, which reflects recovery of a significant portion of the deficiency payments.

With effect from April 1, 2005, a number of incentive schemes operate to encourage DLHs to provide an appropriate quality of service. Payments in respect of each failure to meet a prescribed standard of service are set out in regulations. The aggregate of payments that may be due is uncapped, although payments are excused in certain force majeure circumstances. In storm conditions the obligations relating to the period within which supplies should be restored are relaxed and the overall, annual exposure under the restoration standard in storm conditions is limited to 2% of a DLH's allowed revenue. There also is a discretionary reward scheme of up to £1 million per annum, and other incentive schemes pursuant to which a DLH's allowed revenue may increase by up to 3.3% or decrease by up to 3.5% in any year.

20. Commitments and Contingencies

MidAmerican Energy, Kern River, Northern Natural Gas, CE Electric UK, CalEnergy Generation-Domestic and HomeServices have non-cancelable operating leases primarily for computer equipment, office space and rail cars. Rental payments on non-cancelable operating leases totaled $77.4 million for 2005, $71.1 million for 2004, and $65.8 million for 2003. The minimum payments under these leases are $74.8 million, $67.8 million, $57.0 million, $45.7 million, and $35.3 million for the years 2006 through 2010, respectively, and $96.2 million for the total of the years thereafter.

MidAmerican Energy

Fuel and Energy Commitments

MidAmerican Energy has coal supply and related transportation contracts for its fossil-fueled generating stations. As of December 31, 2005, the contracts, with expiration dates ranging from 2006 to 2010, require minimum payments of $87.4 million, $70.0 million, $35.6 million, $35.2 million and $16.1 million for the years 2006 through 2010, respectively. MidAmerican Energy expects to supplement these coal contracts with additional contracts and spot market purchases to fulfill its future fossil fuel needs. Additionally, MidAmerican Energy has a transportation contract for a natural gas-fired generating plant. The contract, which expires in 2012, requires minimum annual payments of $6.0 million.

MidAmerican Energy also has contracts to purchase electric capacity. As of December 31, 2005, the contracts, with expiration dates ranging from 2006 to 2028, require minimum payments of $26.2 million, $27.5 million, $35.7 million, $28.9 million and $9.4 million for the years 2006 through 2010, respectively, and $165.3 million for the total of the years thereafter.

MidAmerican Energy has various natural gas supply and transportation contracts for its gas operations. As of December 31, 2005, the contracts, with expiration dates ranging from 2006 to 2017, require minimum payments of $61.5 million, $51.0 million, $16.7 million, $10.9 million and $5.7 million for the years 2006 through 2010, respectively, and $16.9 million for the total of the years thereafter.

MidAmerican Energy is the lessee on operating leases for coal railcars that contain guarantees of the residual value of such equipment throughout the term of the leases. Events triggering the residual guarantees include termination of the lease, loss of the equipment or purchase of the equipment. Lease terms are for five years with provisions for extensions. As of December 31, 2005, the maximum amount of such guarantees specified in these leases totaled $29.4 million. These guarantees are not reflected in the accompanying consolidated balance sheets.

On February 12, 2003, MidAmerican Energy executed a contract with Mitsui & Co. Energy Development, Inc. (''Mitsui'') for engineering, procurement and construction of a 790 MW (based on expected accreditation) coal-fired generating plant expected to be completed in the summer of 2007. MidAmerican Energy currently holds a 60.67% individual ownership interest as a tenant in common with the other owners of the plant. Under the contract, MidAmerican Energy is allowed to defer payments, including the other owners' shares, for up to $200.0 million of billed construction costs through the end of the project. Deferred payments as of December 31, 2005 and 2004, totaled $200.0 million and $152.3 million, respectively, and are reflected in other long-term accrued liabilities in the accompanying consolidated balance sheets.

An asset representing the other owners' share of the deferred payments is reflected in deferred charges and other assets in the accompanying consolidated balance sheets and totaled $78.7 million and $59.9 million, respectively, as of December 31, 2005 and 2004. MidAmerican Energy will bill each of the other owners for its share of the deferred payments when payment is made to Mitsui.

Air Quality

MidAmerican Energy is subject to applicable provisions of the Clean Air Act and related air quality standards promulgated by the United States Environmental Protection Agency (''EPA''). The Clean Air Act provides the framework for regulation of certain air emissions and permitting and monitoring associated with those emissions. MidAmerican Energy believes it is in material compliance with current air quality requirements.

The EPA has in recent years implemented more stringent national ambient air quality standards for ozone and new standards for fine particulate matter. These standards set the minimum level of air quality that must be met throughout the United States. Areas that achieve the standards, as determined by ambient air quality monitoring, are characterized as being in attainment of the standard. Areas that fail to meet the standard are designated as being nonattainment areas. Generally, once an area has been designated as a nonattainment area, sources of emissions that contribute to the failure to achieve the ambient air quality standards are required to make emissions reductions. The EPA has concluded that the entire state of Iowa, where MidAmerican Energy's major emission sources are located, is in attainment of the ozone standards and the fine particulate matter standards.

On December 20, 2005, the EPA proposed strengthening the ambient air quality standard for fine particulates, suggesting a range of prospective new levels for fine particulate matter and suggesting maintaining the annual standard at the current level while reducing the 24-hour standard. The EPA established a 90-day public comment period on its plan, which closes on April 17, 2006, and final rules are anticipated to be issued in September 2006. Until the public comment period closes and the EPA takes final action on the proposal, the impact of the proposed rules on MidAmerican Energy cannot be determined.

On March 10, 2005, the EPA released the final Clean Air Interstate Rule (''CAIR''), calling for reductions of sulfur dioxide (''SO_2'') and nitrogen oxides (''NO_x'') emissions in the eastern United States through, at each state's option, a market-based cap and trade system, emission reductions, or both. The state of Iowa is implementing rules that exercise the option of the market-based cap and trade system. While the state of Iowa has been determined to be in attainment of the ozone and fine particulate standards, Iowa has been found to significantly contribute to nonattainment of the fine particulate standard in Cook County, Illinois; Lake County, Indiana; Madison County, Illinois; St. Clair County, Illinois; and Marion County, Indiana. The EPA has also concluded that emissions from Iowa significantly contribute to ozone nonattainment in Kenosha and Sheboygan counties in Wisconsin and Macomb County, Michigan. Under the final CAIR, the first phase reductions of SO_2 emissions are effective on January 1, 2010, with the second phase reductions effective January 1, 2015. For NO_x, the first phase emissions reductions are effective January 1, 2009, and the second phase reductions are effective January 1, 2015. The CAIR calls for overall reductions of SO_2 and NO_x in Iowa of 68% and 67%, respectively, by 2015. The CAIR will impact the operation of MidAmerican Energy's generating facilities and will require MidAmerican Energy to either reduce emissions from those facilities through the installation of emission controls or purchase additional emission allowances, or some combination thereof.

On March 15, 2005, the EPA released the final Clean Air Mercury Rule (''CAMR''). The CAMR utilizes a market-based cap and trade mechanism to reduce mercury emissions from coal-burning power plants from the current nationwide level of 48 tons to 15 tons at full implementation. The CAMR's two-phase reduction program requires initial reductions of mercury emission in 2010 and an overall reduction in mercury emissions from coal-burning power plants of 70% by 2018. The CAMR will impact MidAmerican Energy's coal-burning generating facilities and will require MidAmerican Energy to either reduce emissions from those facilities through the installation of emission controls or purchase additional emission allowances, or some combination thereof.

Table of Contents

The CAIR or the CAMR could, in whole or in part, be superseded or made more stringent by one of a number of multi-pollutant emission reduction proposals currently under consideration at the federal level, including pending legislative proposals that contemplate 70% to 90% reductions of SO_2, NO_X and mercury, as well as possible new federal regulation of carbon dioxide and other gases that may affect global climate change. In addition to any federal legislation that could be enacted by Congress to supersede the CAIR and the CAMR, the rules could be changed or overturned as a result of litigation. The sufficiency of the standards established by both the CAIR and the CAMR has been legally challenged in the United States District Court for the District of Columbia. Until the court makes a determination regarding the merits of the challenges to the CAIR and the CAMR, the full impact of the rules on MidAmerican Energy cannot be determined.

MidAmerican Energy has implemented a planning process that forecasts the site-specific controls and actions that may be required to meet emissions reductions as promulgated by the EPA. In accordance with an Iowa law passed in 2001, MidAmerican Energy has on file with the IUB its current multi-year plan and budget for managing SO_2 and NO_X from its generating facilities in a cost-effective manner. The plan, which is required to be updated every two years, provides specific actions to be taken at each coal-fired generating facility and the related costs and timing for each action. On July 17, 2003, the IUB issued an order that affirmed an administrative law judge's approval of the initial plan filed on April 1, 2002, as amended. On October 4, 2004, the IUB issued an order approving MidAmerican Energy's second biennial plan as revised in a settlement MidAmerican Energy entered into with the OCA. That plan covers the time period from April 1, 2004 through December 31, 2006. Neither IUB order resulted in any changes to electric rates for MidAmerican Energy. The effect of the orders is to approve the prudence of expenditures made consistent with the plans. Pursuant to an unrelated rate settlement agreement approved by the IUB on October 17, 2003, if, prior to January 1, 2011, capital and operating expenditures to comply with environmental requirements cumulatively exceed $325 million, then MidAmerican Energy may seek to recover the additional expenditures from customers.

Under the existing New Source Review (''NSR'') provisions of the Clean Air Act, a utility is required to obtain a permit from the EPA or a state regulatory agency prior to (1) beginning construction of a new major stationary source of an NSR-regulated pollutant or

(2) making a physical or operational change to an existing facility that potentially increases emissions, unless the changes are exempt under the regulations (including routine maintenance, repair and replacement of equipment). In general, projects subject to NSR regulations are subject to 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 a Best Available Control Technology analysis and evaluate the most effective emissions controls. These controls must be installed in order to receive a permit. Violations of NSR regulations, which may be alleged by the EPA, states and environmental groups, among others, potentially subject a utility to material expenses for fines and other sanctions and remedies including requiring installation of enhanced pollution controls and funding supplemental environmental projects.

In recent years, the EPA has requested from several utilities information and supporting documentation regarding their capital projects for various generating plants. The requests were issued as part of an industry-wide investigation to assess compliance with the NSR and the New Source Performance Standards of the Clean Air Act. In December 2002 and April 2003, MidAmerican Energy received requests from the EPA to provide documentation related to its capital projects from January 1, 1980, to April 2003 for a number of its generating plants. MidAmerican Energy has submitted information to the EPA in responses to these requests, and there are currently no outstanding data requests pending from the EPA. MidAmerican Energy cannot predict the outcome of these requests at this time.

In 2002 and 2003, the EPA proposed various changes to its NSR rules that clarify what constitutes routine repair, maintenance and replacement for purposes of triggering NSR requirements. These changes have been subject to legal challenge and, until such time as the legal challenges are resolved and the rules are effective, MidAmerican Energy will continue to manage projects at its generating plants in accordance with the rules in effect prior to 2002. On June 24, 2005, the Washington D.C.

Table of Contents

Circuit Court upheld portions of the EPA's 2002 NSR rule but invalidated other portions. On October 13, 2005, the EPA proposed a rule that would change or clarify how emission increases are to be calculated for purposes of determining the applicability of the NSR permitting program for modifications to existing power plants and opened a public comment period, which ended on February 17, 2006. The impact of these proposed changes on MidAmerican Energy cannot be determined until after the rule is finalized and implemented.

Nuclear Decommissioning Costs

Expected nuclear decommissioning costs for Quad Cities Station have been developed based on a site-specific decommissioning study that includes decontamination, dismantling, site restoration, dry fuel storage cost and an assumed shutdown date. Quad Cities Station nuclear decommissioning costs are included in base rates in Iowa tariffs.

MidAmerican Energy's share of estimated decommissioning costs for Quad Cities Station as of December 31, 2005, was $163.0 million and is the ARO liability for Quad Cities Station. MidAmerican Energy has established trusts for the investment of funds for decommissioning the Quad Cities Station. The fair value of the assets held in the trusts was $228.1 million at December 31, 2005 and is reflected in other investments in the accompanying consolidated balance sheets.

Nuclear Insurance

MidAmerican Energy maintains financial protection against catastrophic loss associated with its interest in Quad Cities Station through a combination of insurance purchased by Exelon Generation Company, LLC (''Exelon Generation'') (the operator and joint owner of 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. The general types of coverage are: nuclear liability, property coverage and nuclear worker liability.

Exelon Generation purchases private market nuclear liability insurance for Quad Cities Station in the maximum available amount of $300.0 million, which includes coverage for MidAmerican Energy's ownership. In accordance with the Price-Anderson Amendments Act of 1988, as amended and extended by the Energy Policy Act, excess liability protection above that amount is provided by a mandatory industry-wide Secondary Financial Protection program under which the licensees of nuclear generating facilities could be assessed for liability incurred due to a serious nuclear incident at any commercial nuclear reactor in the United States. Currently, MidAmerican Energy's aggregate maximum potential share of an assessment for Quad Cities Station is approximately $50.3 million per incident, payable in installments not to exceed $7.5 million annually.

The property insurance covers property damage, stabilization and decontamination of the facility, disposal of the decontaminated material and premature decommissioning arising out of a covered loss. For Quad Cities Station, Exelon Generation purchases primary and excess property insurance protection for the combined interests in Quad Cities Station, with coverage limits totaling $2.1 billion. MidAmerican Energy also directly purchases extra expense coverage for its share of replacement power and other extra expenses in the event of a covered accidental outage at Quad Cities Station. The property and related coverages purchased directly by MidAmerican Energy and by Exelon Generation, which includes the interests of MidAmerican Energy, are underwritten by an industry mutual insurance company and contain provisions for retrospective premium assessments should two or more full policy-limit losses occur in one policy year. Currently, the maximum retrospective amounts that could be assessed against MidAmerican Energy from industry mutual policies for its obligations associated with Quad Cities Station total $9.0 million.

The master nuclear worker liability coverage, which is purchased by Exelon Generation for Quad Cities Station, is an industry-wide guaranteed-cost policy with an aggregate limit of $300.0 million for the nuclear industry as a whole, which is in effect to cover tort claims of workers in nuclear-related industries.

Legal Matters

In addition to the proceedings described below, the Company is currently party to various items of litigation or arbitration in the normal course of business, none of which are reasonably expected by the Company to have a material adverse effect on its financial position, results of operations or cash flows.

CalEnergy Generation-Foreign

Pursuant to the share ownership adjustment mechanism in the CE Casecnan stockholder agreement, which is based upon pro forma financial projections of the Casecnan project prepared following commencement of commercial operations, in February 2002, MEHC's indirect wholly-owned subsidiary, CE Casecnan Ltd., advised the minority stockholder 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. On July 8, 2002, LPG filed a complaint in the Superior Court of the State of California, City and County of San Francisco against CE Casecnan Ltd., KEIL Casecnan Ltd. (''KE''), a former stockholder, 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 On January 21, 2004, CE Casecnan Ltd., LPG and CE Casecnan entered into a status quo agreement pursuant to which the parties agreed to set aside certain distributions related to the shares subject to the LPG dispute and CE Casecnan agreed not to take any further actions with respect to such distributions without at least 15 days prior notice to LPG. Accordingly, 15% of the CE Casecnan dividend distributions declared in 2004 and 2005, totaling $17.6 million, was set aside in a separate bank account in the name of CE Casecnan and is shown as restricted cash and short-term investments and other current liabilities in the accompanying consolidated balance sheets.

On August 4, 2005, the court issued a decision, ruling in favor of LPG on five of the eight disputed issues in the first phase of the litigation. On September 12, 2005, LPG filed a motion seeking the release of the funds which have been set aside pursuant to the status quo agreement referred to above. MEHC and CE Casecnan Ltd. filed an opposition to the motion on October 3, 2005, and at the hearing on October 26, 2005, the court denied LPG's motion. On January 3, 2006, the court entered a judgment in favor of LPG against CE Casecnan Ltd. and KE. According to the judgment LPG would retain its ownership of 15% of the shares of CE Casecnan and distributions of the amounts deposited into escrow plus interest at 9% per annum. On February 28, 2006, CE Casecnan Ltd. and KE filed an appeal of this judgment and the August 4, 2005 decision. The appeal is expected to be resolved sometime in 2007. The impact, if any, of this litigation on the Company cannot be determined at this time.

In February 2003, San Lorenzo Ruiz Builders and Developers Group, Inc. (''San Lorenzo''), an original shareholder substantially all of whose shares in CE Casecnan were purchased by MEHC in 1998, threatened to initiate legal action against the Company in the Philippines in connection with certain aspects of its option to repurchase such shares. On July 1, 2005, MEHC and CE Casecnan Ltd. commenced an action against San Lorenzo in the District Court of Douglas County, Nebraska, seeking a declaratory judgment as to MEHC's and CE Casecnan Ltd.'s rights vis-à-vis San Lorenzo in respect of such shares. San Lorenzo filed a motion to dismiss on September 19, 2005. The motion was heard on October 21, 2005, and the court took the matter under advisement. Subsequently, San Lorenzo purported to exercise its option to repurchase such shares. On January 30, 2006, San Lorenzo filed a counterclaim against MEHC and CE Casecnan Ltd. seeking declaratory relief that it has effectively exercised its option to purchase 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 impact, if any, of San Lorenzo's purported exercise of its option and the Nebraska litigation on the Company cannot be determined at this time. The Company intends to vigorously defend the counterclaims.

21. Pension and Postretirement Commitments

Domestic Operations

MidAmerican Energy sponsors a noncontributory defined benefit pension plan covering substantially all employees of MEHC and its domestic energy subsidiaries. Benefit obligations under the plan are based on a cash balance arrangement for salaried employees and certain union employees and final average pay formulas for most union employees. Funding to the established trust is based upon the actuarially determined costs of the plan and the requirements of the Internal Revenue Code and the Employee Retirement Income Security Act. The Company also maintains noncontributory, nonqualified defined benefit supplemental executive retirement plans for active and retired participants.

MidAmerican Energy also sponsors certain postretirement health care and life insurance benefits covering substantially all retired employees of MEHC and its domestic energy subsidiaries. Under the plans, covered employees may become eligible for these benefits if they reach retirement age while working for the Company. On July 1, 2004, the postretirement benefit plan was amended for non-union participants. As a result, non-union employees hired July 1, 2004, and after are no longer eligible for postretirement benefits other than pensions. The plan, as amended, establishes retiree medical accounts for participants to which the Company makes fixed contributions until the employee's retirement. Participants will use such accounts to pay a portion of their medical premiums during retirement. The Company retains the right to change these benefits anytime, subject to provisions in its collective bargaining agreements.

For purposes of calculating the expected return on pension plan assets, a market-related value is used. Market-related value is equal to fair value except for gains and losses on equity investments which are amortized into market-related value on a straight-line basis over five years. Net periodic pension benefit cost, including supplemental retirement, and postretirement benefit cost included the following components for MEHC and its domestic energy subsidiaries for the years ended December 31:

	Pension Cost			Postretirement Cost		
	2005	2004	2003	2005	2004	2003
	(in thousands)					
Service cost	$ 25,840	$ 25,568	$ 24,693	$ 6,669	$ 7,842	$ 8,175
Interest cost	36,518	35,159	34,533	13,455	15,716	16,065
Expected return on plan assets	(38,188)	(38,258)	(38,396)	(9,611)	(8,437)	(6,008)
Amortization of net transition obligation	—	(792)	(2,591)	2,403	3,283	4,110
Amortization of prior service cost	2,766	2,758	2,761	—	296	593
Amortization of prior year (gain) loss	1,271	1,569	1,483	1,554	3,299	3,716
Regulatory expense	—	—	3,320	—	—	—
Net periodic benefit cost	$ 28,207	$ 26,004	$ 25,803	$14,470	$21,999	$26,651

Weighted-average assumptions used to determine benefit obligations at December 31:

	2005	2004	2003	2005	2004	2003
Discount rate	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%
Rate of compensation increase	5.00%	5.00%	5.00%		Not applicable	

Table of Contents

Weighted-average assumptions used to determine net benefit cost for the years ended December 31:

	2005	2004	2003	2005	2004	2003
Discount rate	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%
Expected return on plan assets	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Rate of compensation increase	5.00%	5.00%	5.00%		Not applicable	

Assumed health care cost trend rates at December 31:

	2005	2004
Health care cost trend rate assumed for next year	9.00%	10.00%
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	2010	2010

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects (in thousands):

	Increase (Decrease) in Expense	
	One Percentage-Point Increase	One Percentage-Point Decrease
Effect on total service and interest cost	$ 2,418	$ (1,891)
Effect on postretirement benefit obligation	$26,434	$(21,350)

Table of Contents

The following table presents a reconciliation of the beginning and ending balances of the benefit obligation, fair value of plan assets and the funded status of the aforementioned plans to the net amounts measured and recognized in the accompanying consolidated balance sheets as of December 31 (in thousands):

	Pension Benefits		Postretirement Benefits	
	2005	2004	2005	2004
Reconciliation of the fair value of plan assets:				
Fair value of plan assets at beginning of year	$ 591,628	$ 551,568	$179,375	$157,849
Employer contributions	5,786	5,083	16,615	23,782
Participant contributions	—	—	9,096	7,733
Actual return on plan assets	46,966	63,151	5,958	9,698
Benefits paid	(31,551)	(28,174)	(20,144)	(19,687)
Fair value of plan assets at end of year	612,829	591,628	190,900	179,375
Reconciliation of benefit obligation:				
Benefit obligation at beginning of year	657,406	620,048	256,044	297,433
Service cost	25,840	25,568	6,669	7,841
Interest cost	36,518	35,159	13,455	15,716
Participant contributions	—	—	9,096	7,733
Plan amendments	(3,184)	—	(421)	(19,219)
Actuarial (gain) loss	(6,917)	4,805	(15,141)	(33,773)

Benefits paid	(31,551)	(28,174)	(20,144)	(19,687)
Benefit obligation at end of year	678,112	657,406	249,558	256,044
Funded status	(65,283)	(65,778)	(58,658)	(76,669)
Amounts not recognized in consolidated balance sheets:				
Unrecognized net (gain) loss	(51,285)	(34,319)	29,725	42,768
Unrecognized prior service cost	9,207	15,157	—	—
Unrecognized net transition obligation (asset)	—	—	16,820	19,641
Net amount recognized in the consolidated balance sheets	$(107,361)	$ (84,940)	$ (12,113)	$ (14,260)
Net amount recognized in the consolidated balance sheets consists of:				
Accrued benefit liability	$(135,506)	$(117,357)	$ (12,113)	$ (14,260)
Intangible assets	11,939	14,653	—	—
Regulatory assets	11,694	17,764	—	—
Accumulated other comprehensive income	4,512	—	—	—
Net amount recognized	$(107,361)	$ (84,940)	$ (12,113)	$ (14,260)

The portion of the pension projected benefit obligation, included in the table above, related to the supplemental executive retirement plan was $105.7 million and $106.5 million as of December 31, 2005 and 2004, respectively. The supplemental executive retirement plan has no assets, and accordingly, the fair value of its plan assets was zero as of December 31, 2005 and 2004. The accumulated benefit obligation for all defined benefit pension plans was $608.4 million and $585.4 million at December 31, 2005 and 2004, respectively. Of these amounts, the supplemental executive retirement plan accumulated benefit obligation totaled $102.2 million and $102.3 million for 2005 and 2004, respectively.

Although the supplemental executive retirement plan had no assets as of December 31, 2005, the Company has Rabbi trusts that hold corporate-owned life insurance and other investments to provide funding for the future cash requirements. Because this plan is nonqualified, the assets in the Rabbi

Table of Contents

trusts are not considered plan assets. The cash surrender value of the policies included in the Rabbi trusts plus the fair market value of other Rabbi trust investments was $102.9 million and $98.8 million at December 31, 2005 and 2004, respectively.

Plan Assets

The Company’s investment policy for its domestic pension and postretirement plans is to balance risk and return through a diversified portfolio of high-quality equity and fixed income securities. Equity targets for the pension and postretirement plans are as indicated in the tables below. Maturities for fixed income securities are managed to targets consistent with prudent risk tolerances. Sufficient liquidity is maintained to meet near-term benefit payment obligations. The plans retain outside investment advisors to manage plan investments within the parameters outlined by the Company’s Pension and Employee Benefits Plans Administrative Committee. The weighted average return on assets assumption is based on historical performance for the types of assets in which the plans invest.

The Company’s pension plan asset allocations at December 31, 2005 and 2004 are as follows:

	Percentage of Plan Assets at December 31		
Asset Category	**2005**	**2004**	**Target Range**
Equity securities	66%	71%	65-75%
Debt securities	26%	22%	20-30%
Real estate	6%	6%	0-10%
Other	2%	1%	0-5%
Total	100%	100%	

The Company’s postretirement benefit plan asset allocations at December 31, 2005 and 2004 are as follows:

	Percentage of Plan Assets at December 31		
Asset Category	**2005**	**2004**	**Target Range**
Equity securities	50%	49%	45-55%
Debt securities	48%	47%	45-55%
Other	2%	4%	0-10%
Total	100%	100%	

Cash Flows

The Company’s expected benefit payments to participants for its pension and postretirement plans for 2006 through 2010 and for the five years thereafter are summarized below (in thousands):

	Pension Benefits	Postretirement Benefits Gross	Medicare Subsidy	Net of Subsidy
2006	$ 32,545	$ 14,054	$ 2,350	$11,704
2007	34,771	15,336	2,533	12,803
2008	37,347	16,434	2,719	13,715
2009	41,125	17,419	2,888	14,531
2010	45,030	18,525	3,032	15,493
2011-2015	275,118	107,131	17,728	89,403

Employer contributions to the domestic pension and postretirement plans are currently expected to be $6.7 million and $14.5 million, respectively, for 2006. The Company’s policy is to contribute the minimum required amount to the pension plan and the amount expensed to its postretirement plans.

The Company sponsors defined contribution pension plans (401(k) plans) covering substantially all domestic 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. The Company’s total contributions were $17.3 million, $17.1 million and $15.5 million for 2005, 2004 and 2003, respectively.

In December 2003, the President signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (‘‘Medicare Act’’). The Medicare Act introduces a prescription drug benefit under Medicare as well as a subsidy to sponsors of retiree health care plans that provide a benefit to participants that is at least actuarially equivalent to Medicare Part D. Detailed regulations pertaining to the Medicare Act were promulgated in 2004 resulting in a $23.8 million subsidy to the Company to be used for any valid business purpose. The subsidy is reflected as an actuarial gain in benefit obligation in 2004 in the table above. The impact of the Medicare Act on the net periodic postretirement benefit expense is reflected in 2005.

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 substantially all employees of CE Electric UK’s certain wholly-owned subsidiaries.

For purposes of calculating the expected return on pension plan assets, a market-related value is used. Market-related value is equal to fair value except for gains and losses on equity investments which are amortized into market-related value on a straight-line basis over five years. Net periodic pension benefit cost included the following components for CE Electric UK for the years ended December 31:

	2005	2004	2003
Service cost	$ 15,292	$ 12,100	$ 9,485
Interest cost	76,460	73,515	62,632
Expected return on plan assets	(96,849)	(98,448)	(89,124)
Amortization of prior service cost	1,890	1,915	1,472
Amortization of loss	22,761	12,742	537
Net periodic expense (benefit)	$ 19,554	$ 1,824	$(14,998)

Weighted-average assumptions used to determine benefit obligations at December 31:

	2005	2004	2003
Discount rate	4.75%	5.25%	5.50%
Rate of compensation increase	2.75%	2.75%	2.75%

Weighted-average assumptions used to determine net benefit cost for years ended December 31:

	2005	2004	2003
Discount rate	5.25%	5.50%	5.75%
Expected return on plan assets	7.00%	7.00%	7.00%
Rate of compensation increase	2.75%	2.75%	2.50%

The following table presents a reconciliation of the beginning and ending balances of the benefit obligation, fair value of plan assets and the funded status of the UK Plan to the net amounts measured and recognized in the accompanying consolidated balance sheets as of December 31 (in thousands):

	2005	2004
Reconciliation of the fair value of plan assets:		
Fair value of plan assets at beginning of year	$1,364,722	$1,206,216
Employer contributions	55,663	17,600
Participant contributions	6,190	6,417
Actual return on plan assets	211,723	106,515
Benefits paid	(67,176)	(65,265)
Foreign currency exchange rate changes	(151,559)	93,239
Fair value of plan assets at end of year	1,419,563	1,364,722

Reconciliation of benefit obligation:		
Benefit obligation at beginning of year	1,571,579	1,334,587
Service cost	15,292	12,100
Interest cost	76,460	73,515
Participant contributions	6,190	6,417
Benefits paid	(67,176)	(65,265)
Experience loss and change of assumptions	127,617	104,315
Foreign currency exchange rate changes	(170,645)	105,910
Benefit obligation at end of year	1,559,317	1,571,579
Funded status	(139,754)	(206,857)
Unrecognized net loss	561,050	614,182
Net amount recognized in the consolidated balance sheets	$ 421,296	$ 407,325
Amounts recognized in the consolidated balance sheets consist of:		
Prepaid benefit cost	$ 421,296	$ 407,325
Accrued benefit liability	(492,550)	(561,988)
Intangible assets	12,908	16,119
Accumulated other comprehensive income	479,642	545,869
Net amount recognized	$ 421,296	$ 407,325

The accumulated benefit obligation for the defined benefit pension plan was $1.5 billion at December 31, 2005 and 2004, respectively.

The Company recorded a minimum pension liability as of December 31, 2005 and 2004 in the amount of $479.6 million and $545.9 million, respectively. The pension liability is primarily due to the decline in market value of the pension plan assets during 2002 combined with the effects of lower discount rates and higher rates of compensation increases used to value the plan's liabilities in 2005 and 2004, as well as, mortality assumption changes which increased the liability. As of December 31, 2005 and 2004, the minimum pension liability is measured as the amount of the plan's accumulated benefit obligation that is in excess of the plan's market value of assets at December 31, 2005 and 2004 plus the prepaid asset balance. A charge equal to the excess was recorded to the Company's stockholders' equity, net of income tax benefits, as a component of comprehensive loss in the amount of $(46.4) million and $46.4 million in 2005 and 2004, respectively. This adjustment does not impact current year earnings, or the funding requirements of the plan.

Table of Contents

Plan Assets

CE Electric UK's investment policy for its pension and postretirement plans is to balance risk and return through a diversified portfolio of high-quality equity and fixed income securities. Maturities for fixed income securities are managed such that sufficient liquidity exists to meet near-term benefit payment obligations. The plans retain outside investment advisors to manage plan investments within the parameters outlined by the Benefits Committee of subsidiaries of CE Electric UK. The weighted average return on assets assumption is based on historical performance for the types of assets in which the plans invest.

CE Electric UK's pension plan asset allocation consists of the following at December 31:

	Percentage of Plan Assets at December 31,		
	2005	**2004**	**Target**
Asset Category			
Equity securities	51%	49%	50%
Debt securities	37%	39%	40%
Real estate	11%	11%	10%
Other	1%	1%	—%
Total	100%	100%	100%

Cash Flows

CE Electric UK's expected benefit payments relative to the UK Plan for 2006 through 2010 and for the five years thereafter are summarized below (in millions):

2006	$ 66.2
2007	67.1
2008	67.7
2009	70.2
2010	70.7
2011-2015	378.9

The triennial process of valuing the UK Plan's assets and liabilities, which valued the plan assets and liabilities as of March 31, 2004, was completed in 2005. This valuation set a revised level of contributions for the next three years. The report of the actuaries conducting the valuation showed a funding deficiency of £190.3 million. Based on this valuation, CE Electric UK will contribute £23.1 million to the UK Plan each year in respect of the existing funding deficiency. The amount in respect of the funding deficiency has been calculated based on eliminating the funding deficiency over 12 years commencing April 1, 2005. Employer contributions to the UK Plan for the year ended December 31, 2005 totaled $55.7 million and consisted of $24.6 million to fund ongoing liabilities and $31.1 million in respect of the existing funding deficiency. Employer contributions to the UK Plan, including the £23.1 million deficiency funding, are currently expected to be £35.0 million for 2006.

Table of Contents

22. Segment Information

The Company has identified seven reportable segments: MidAmerican Energy, Kern River, Northern Natural Gas, CE Electric UK, CalEnergy Generation-Foreign, CalEnergy Generation-Domestic and HomeServices. The Company's determination of reportable segments considers the strategic units under which the Company is 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. The reportable segment financial information includes all necessary adjustments and eliminations needed to conform to the Company's significant accounting policies including the allocation of goodwill. Additionally, the activity of the Company's Mineral Assets, which was previously reported in the CalEnergy Generation-Domestic reportable segment, is presented as discontinued operations within the accompanying consolidated financial statements. Information related to the Company's reportable segments is shown below (in thousands):

	Year Ended December 31,		
	2005	2004	2003
Operating revenue:			
MidAmerican Energy	$3,166,084	$2,701,700	$2,600,239
Kern River	323,561	316,131	260,182
Northern Natural Gas	569,055	544,822	486,878
CE Electric UK	884,115	936,364	829,993
CalEnergy Generation — Foreign	312,346	307,395	326,454
CalEnergy Generation — Domestic	33,825	38,960	45,154
HomeServices	1,868,495	1,756,454	1,476,569
Total reportable segments	7,157,481	6,601,826	6,025,469
Corporate/other(1)	(41,942)	(48,438)	(59,839)
Total operating revenue	$7,115,539	$6,553,388	$5,965,630
Depreciation and amortization:			
MidAmerican Energy	$ 269,142	$ 266,409	$ 281,001
Kern River	62,365	53,250	36,771
Northern Natural Gas	30,351	67,913	52,716
CE Electric UK	135,731	137,746	125,000
CalEnergy Generation — Foreign	90,391	90,328	87,928
CalEnergy Generation — Domestic	8,748	8,721	8,882
HomeServices	17,774	20,827	17,560
Total reportable segments	614,502	645,194	609,858
Corporate/other(1)	(6,304)	(6,985)	(6,924)
Total depreciation and amortization	$ 608,198	$ 638,209	$ 602,934
Interest expense:			
MidAmerican Energy	$ 137,658	$ 125,189	$ 123,395
Kern River	73,158	76,671	79,272
Northern Natural Gas	52,590	53,100	56,008
CE Electric UK	217,909	202,067	180,207
CalEnergy Generation — Foreign	31,302	42,696	59,603
CalEnergy Generation — Domestic	18,266	18,971	19,736
HomeServices	2,442	2,837	3,864
Total reportable segments	533,325	521,531	522,085
Corporate/other(1)	173,210	184,811	189,083
Parent company subordinated debt(2)	184,444	196,875	49,788
Total interest expense	$ 890,979	$ 903,217	$ 760,956

Table of Contents

	Year Ended December 31,		
	2005	2004	2003
Operating income:			
MidAmerican Energy	$ 381,084	$ 355,947	$ 367,868
Kern River	204,488	204,776	180,978
Northern Natural Gas	208,848	190,337	175,770
CE Electric UK	483,935	497,358	445,803
CalEnergy Generation — Foreign	184,986	188,529	197,527
CalEnergy Generation — Domestic	15,059	21,468	21,403
HomeServices	125,321	112,928	92,874
Total reportable segments	1,603,721	1,571,343	1,482,223
Corporate/other(1)	(75,039)	(45,942)	(32,408)
Total operating income	1,528,682	1,525,401	1,449,815
Interest expense	(890,979)	(903,217)	(760,956)
Capitalized interest	16,716	20,040	30,494
Interest and dividend income	58,070	38,889	47,908
Other income	74,516	128,205	96,643
Other expense	(22,127)	(10,125)	(5,913)
Total income from continuing operations before income tax expense, minority interest and preferred dividends of subsidiaries and equity income	$ 764,878	$ 799,193	$ 857,991
Income tax expense:			
MidAmerican Energy	$ 91,371	$ 87,336	$ 110,078
Kern River	50,421	54,148	51,319
Northern Natural Gas	70,549	84,423	50,599
CE Electric UK	92,766	80,211	91,539
CalEnergy Generation — Foreign	55,855	62,548	62,130

CalEnergy Generation — Domestic	(995)	1,217	1,078
HomeServices	56,359	52,996	43,587
Total reportable segments	416,326	422,879	410,330
Corporate/other(1)	(171,617)	(157,893)	(140,054)
Total income tax expense	$ 244,709	$ 264,986	$ 270,276
Capital expenditures:			
MidAmerican Energy	$ 700,954	$ 633,807	$ 346,449
Kern River	7,367	26,936	433,125
Northern Natural Gas	124,739	138,747	104,400
CE Electric UK	342,585	334,458	301,896
CalEnergy Generation — Foreign	562	4,633	8,497
CalEnergy Generation — Domestic	574	1,341	6,619
HomeServices	18,874	20,786	18,311
Total reportable segments	1,195,655	1,160,708	1,219,297
Corporate/other(1)	582	18,682	71
Total capital expenditures	$1,196,237	$1,179,390	$1,219,368

Table of Contents

	As of December 31,		
	2005	2004	2003
Total assets:			
MidAmerican Energy	$ 8,003,423	$ 7,274,999	$ 6,596,849
Kern River	2,099,625	2,135,265	2,200,201
Northern Natural Gas	2,245,308	2,200,846	2,167,621
CE Electric UK	5,742,718	5,794,887	5,038,880
CalEnergy Generation — Foreign	643,130	767,465	951,155
CalEnergy Generation — Domestic	555,078	553,741	1,113,172
HomeServices	814,280	737,085	567,736
Total reportable segments	20,103,562	19,464,288	18,635,614
Corporate/other(1)	89,398	439,274	509,338
Total assets	$20,192,960	$19,903,562	$19,144,952
Long-lived assets:			
MidAmerican Energy	$ 4,447,509	$ 3,892,031	$ 3,385,056
Kern River	1,891,027	1,945,094	1,976,213
Northern Natural Gas	1,585,029	1,491,428	1,430,475
CE Electric UK	3,501,218	3,691,459	3,227,723
CalEnergy Generation — Foreign	430,590	520,406	621,674
CalEnergy Generation — Domestic	241,701	256,429	738,296
HomeServices	62,292	59,827	53,518
Total reportable segments	12,159,366	11,856,674	11,432,955
Corporate/other(1)	(243,953)	(249,410)	(251,976)
Total long-lived assets	$11,915,413	$11,607,264	$11,180,979

(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 (i) corporate functions, including administrative costs, interest expense, corporate cash and related interest income, (ii) intersegment eliminations and (iii) fair value adjustments relating to acquisitions.

(2) The Company adopted and applied the provisions of FIN 46R, related to certain finance subsidiaries, as of October 1, 2003. The adoption required the deconsolidation of certain finance subsidiaries, which resulted in amounts that were previously recorded as minority interest and preferred dividends of subsidiaries being prospectively recorded as interest expense in the accompanying consolidated statements of operations. For the years ended December 31, 2005 and 2004, and the three-month period ended December 31, 2003, the Company has recorded $184.4 million, $196.9 million and $49.8 million, respectively, of interest expense related to these securities. In accordance with the requirements of FIN 46R, no amounts prior to adoption of FIN 46R on October 1, 2003 have been reclassified. The amount included in minority interest and preferred dividends of subsidiaries related to these securities for the nine-month period ended September 30, 2003 was $170.2 million.

Table of Contents

The following table shows the change in the carrying amount of goodwill by reportable segment for the years ended December 31, 2005 and 2004 (in thousands):

	MidAmerican Energy	Kern River	Northern Natural Gas	CE Electric UK	CalEnergy Generation Domestic	Home-Services	Total
Balance, January 1, 2004	$2,139,223	$33,900	$379,148	$1,261,583	$126,308	$365,481	$4,305,643
Goodwill from acquisitions during the year	—	—	—	—	—	32,120	32,120
Foreign currency translation adjustment	—	—	—	72,218	—	—	72,218
Impairment losses(1)	—	—	—	—	(52,776)	—	(52,776)
Other goodwill adjustments(2)	(18,098)	—	(24,236)	(4,010)	(1,038)	(3,072)	(50,454)
Balance, December 31, 2004	2,121,125	33,900	354,912	1,329,791	72,494	394,529	4,306,751
Goodwill from acquisitions during the year	—	—	—	—	—	3,630	3,630
Foreign currency translation adjustment	—	—	—	(106,354)	—	—	(106,354)

Other goodwill adjustments(2)	(3,489)	—	(27,808)	(16,229)	(151)	(170)	(47,847)
Balance, December 31, 2005	$2,117,636	$33,900	$327,104	$1,207,208	$ 72,343	$397,989	$4,156,180

(1) Impairment losses relate to the write-off of the Mineral Assets – see Note 17.

(2) Other goodwill adjustments include primarily income tax adjustments.

Table of Contents

PART I. — FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of PacifiCorp:

We have reviewed the accompanying condensed consolidated balance sheet of PacifiCorp and its subsidiaries as of June 30, 2006, and the related condensed consolidated statements of income and retained earnings, and of cash flows for the three-month period then ended. These interim financial statements are the responsibility of PacifiCorp's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to such condensed consolidated interim financial statements as of June 30, 2006, and for the three-month period then ended for them to be in conformity with accounting principles generally accepted in the United States of America.

The accompanying condensed consolidated financial information as of March 31, 2006, and for the three-month period ended June 30, 2005, were not audited or reviewed by us and, accordingly, we do not express an opinion or any form of assurance on them.

/s/ DELOITTE & TOUCHE LLP
Portland, Oregon

August 4, 2006

Table of Contents

PACIFICORP AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME AND RETAINED EARNINGS
(Unaudited)

(Millions of dollars)	Three Months Ended June 30,	
	2006	2005
Revenues	$859.9	$881.4
Operating expenses:		
Energy costs	336.0	352.4
Operations and maintenance	259.6	257.7
Depreciation and amortization	115.7	110.9
Taxes, other than income taxes	26.2	24.5
Total	737.5	745.5
Income from operations	122.4	135.9
Interest expense and other (income) expense:		
Interest expense	69.2	69.3
Interest income	(1.6)	(2.7)
Allowance for borrowed funds	(4.8)	(4.4)
Allowance for equity funds	(6.0)	(2.6)
Other	(0.4)	(2.0)
Total	56.4	57.6
Income from operations before income tax expense	66.0	78.3
Income tax expense	23.4	31.9
Net income	42.6	46.4
Preferred dividend requirement	(0.5)	(0.5)
Earnings on common stock	$ 42.1	$ 45.9
RETAINED EARNINGS AT BEGINNING OF PERIOD	$630.0	$446.4
Net income	42.6	46.4
Cash dividends declared:		
Preferred stock	(0.5)	(0.5)
Common stock	—	(50.8)
RETAINED EARNINGS AT END OF PERIOD	$672.1	$441.5

The accompanying notes are an integral part of these Condensed Consolidated

Financial Statements.

PACIFICORP AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

(Millions of dollars or shares)	June 30, 2006	March 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 73.1	$ 119.6
Accounts receivable	280.9	266.8
Unbilled revenue	173.8	148.2
Inventories at average costs:		
Materials and supplies	128.7	131.2
Fuel	98.3	80.9
Current derivative contract asset	205.0	221.7
Other	95.3	46.9
Total current assets	1,055.1	1,015.3
Property, plant and equipment	15,289.5	15,102.4
Accumulated depreciation and amortization	(5,702.4)	(5,611.5)
	9,587.1	9,490.9
Construction work-in-progress	665.1	618.3
Total property, plant and equipment, net	10,252.2	10,109.2
Other assets:		
Regulatory assets	875.8	884.3
Derivative contract regulatory asset	69.5	94.7
Non-current derivative contract asset	321.1	345.3
Deferred charges and other	283.0	282.5
Total other assets	1,549.4	1,606.8
Total assets	$12,856.7	$12,731.3

The accompanying notes are an integral part of these Condensed Consolidated

Financial Statements.

PACIFICORP AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS, continued
(Unaudited)

(Millions of dollars or shares)	June 30, 2006	March 31, 2006
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 349.8	$ 361.3
Accrued employee expenses	73.2	118.0
Taxes payable	43.1	47.0
Interest payable	50.4	63.0
Current derivative contract liability	97.6	97.9
Deferred income taxes	16.2	16.9
Long-term debt and capital lease obligations, currently maturing	316.9	216.9
Preferred stock subject to mandatory redemption, currently maturing	37.5	3.7
Notes payable and commercial paper	304.2	184.4
Other	119.9	107.0
Total current liabilities	1,408.8	1,216.1
Deferred credits:		
Deferred income taxes	1,604.2	1,621.2
Investment tax credits	65.6	67.6
Regulatory liabilities	814.5	804.7
Non-current derivative contract liability	433.8	461.2
Pension and other post employment liabilities	378.3	385.0
Other	369.2	361.4
Total deferred credits	3,665.6	3,701.1
Long-term debt and capital lease obligations, net of current maturities	3,619.7	3,721.0
Preferred stock subject to mandatory redemption, net of current maturities	—	41.3
Total liabilities	8,694.1	8,679.5
Commitments and contingencies (See Note 4)		
Shareholders' equity:		
Preferred stock	41.3	41.3
Common equity:		
Common shareholder's capital (357.1 no par shares issued and outstanding)	3,456.9	3,381.9

Retained earnings	672.1	630.0
Accumulated other comprehensive (loss) income:		
Unrealized loss on derivative contracts, net of tax of $(2.6)/June	(4.2)	—
Unrealized gain on available-for-sale securities, net of tax of $0.4/June and $1.7/March	0.6	2.7
Minimum pension liability, net of tax of ($2.5)/June and March	(4.1)	(4.1)
Total common equity	4,121.3	4,010.5
Total shareholders' equity	4,162.6	4,051.8
Total liabilities and shareholders' equity	$12,856.7	$12,731.3

The accompanying notes are an integral part of these Condensed Consolidated Financial Statements.

Table of Contents

PACIFICORP AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(Millions of dollars)	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005
Cash flows from operating activities:		
Net income	$ 42.6	$ 46.4
Adjustments to reconcile net income to net cash provided by operating activities:		
Unrealized loss (gain) on derivative contracts, net	31.6	(12.2)
Depreciation and amortization	115.7	110.9
Deferred income taxes and investment tax credits, net	(12.7)	6.2
Regulatory asset/liability establishment and amortization	12.8	26.2
Other	13.7	11.2
Changes in:		
Accounts and other receivables	(39.9)	89.5
Inventories	(14.9)	(11.2)
Amounts due to/from affiliates — MidAmerican, net	(1.2)	—
Amounts due to/from affiliates — ScottishPower, net	—	14.5
Accounts payable and accrued liabilities	(39.2)	(113.9)
Pension and post employment liabilities and other	(46.5)	(27.5)
Net cash provided by operating activities	62.0	140.1
Cash flows from investing activities:		
Capital expenditures	(289.6)	(230.6)
Proceeds from sales of assets	0.1	0.4
Proceeds from available-for-sale securities	39.2	12.3
Purchases of available-for-sale securities	(58.0)	(8.9)
Other	13.6	(3.3)
Net cash used in investing activities	(294.7)	(230.1)
Cash flows from financing activities:		
Changes in short-term debt	119.8	(154.2)
Proceeds from long-term debt, net of issuance costs	—	296.2
Proceeds from equity contribution	73.6	125.0
Dividends paid	(0.5)	(51.3)
Repayments of long-term debt and capital lease obligations	(0.1)	(150.0)
Redemptions of preferred stock	(7.5)	(7.5)
Other	0.9	—
Net cash provided by financing activities	186.2	58.2
Change in cash and cash equivalents	(46.5)	(31.8)
Cash and cash equivalents at beginning of period	119.6	199.3
Cash and cash equivalents at end of period	$ 73.1	$ 167.5

The accompanying notes are an integral part of these Condensed Consolidated Financial Statements.

Table of Contents

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Note 1 — Basis of Presentation and Summary of Significant Accounting Policies

PacifiCorp (which includes PacifiCorp and its subsidiaries) is a United States electric utility company serving retail customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp generates electricity and also engages in electricity sales and purchases on a wholesale basis. The subsidiaries of PacifiCorp support its electric utility operations by providing coal mining and other fuel-related services, as well as environmental remediation. The Condensed Consolidated Financial Statements of PacifiCorp include its integrated electric utility operations and its wholly owned and majority-owned subsidiaries. Intercompany transactions and balances have been eliminated upon consolidation. PacifiCorp is an indirect subsidiary of MidAmerican Energy Holdings Company (‘‘MEHC’’), which is 88.2% owned by Berkshire Hathaway Inc.

The accompanying unaudited Condensed Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America for interim financial information and the instructions for the United States Securities and Exchange Commission (the ''SEC'') Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the disclosures required by accounting principles generally accepted in the United States of America for annual financial statements. In the opinion of management, the unaudited consolidated financial statements include all adjustments, including normal recurring adjustments, considered necessary for a fair presentation of the financial position as of June 30, 2006 and the results of operations and of cash flows for the three-month periods ended June 30, 2006 and 2005. The March 31, 2006 Condensed Consolidated Balance Sheet data was derived from audited financial statements. Certain information and footnote disclosures made in PacifiCorp's Annual Report on Form 10-K for the year ended March 31, 2006, have been condensed or omitted from the interim statements. A portion of the business of PacifiCorp is of a seasonal nature and, therefore, results of operations for the three months ended June 30, 2006 and 2005, are not necessarily indicative of the results for a full year. These Condensed Consolidated Financial Statements should be read in conjunction with the financial statements and related notes in PacifiCorp's Annual Report on Form 10-K for the year ended March 31, 2006.

These interim statements have been prepared using accounting policies consistent with those applied at March 31, 2006, except in relation to new accounting standards and cash flow hedge accounting implemented in April 2006 as described in Note 2 — Derivative Instruments.

On May 10, 2006, the PacifiCorp Board of Directors elected to change PacifiCorp's fiscal year-end from March 31 to December 31. PacifiCorp's report covering the transition period beginning April 1, 2006 and ending December 31, 2006 will be filed on Form 10-K.

New Accounting Standards

FIN 48

In July 2006, the FASB issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes (''*FIN 48*'') — an interpretation of FASB Statement No. 109*, *Accounting for Income Taxes (''*SFAS No. 109*'')*. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in accordance with SFAS No. 109 and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a return. Guidance is also provided on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006. PacifiCorp is currently evaluating the impact of adopting FIN 48 on its consolidated financial position and results of operations.

Note 2 — Derivative Instruments

PacifiCorp's derivative instruments are recorded on the Condensed Consolidated Balance Sheets as assets or liabilities measured at estimated fair value, unless they qualify for the exemptions afforded

Table of Contents

by SFAS No. 133. Changes in the fair value of derivatives are recognized in earnings during the period of change, except for contracts designated as a cash flow hedge or that are probable of recovery in retail rates. Changes in the fair value of contracts probable of recovery in retail rates are deferred as regulatory assets or liabilities pursuant to SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*.

Unrealized gains and losses on derivative contracts not held for trading purposes are presented in the Condensed Consolidated Statements of Income and Retained Earnings as Revenues for sales contracts and as Energy costs and Operations and maintenance expense for purchase contracts and financial swaps. Unrealized and realized gains and losses from all derivative contracts held for trading purposes, including those where physical delivery is required, are recorded on a net basis in the Condensed Consolidated Statements of Income and Retained Earnings as Revenues.

The following table summarizes the amount of the pre-tax unrealized gains and losses included within the Condensed Consolidated Statements of Income and Retained Earnings associated with changes in the fair value of PacifiCorp's derivative contracts that are not included in retail rates or designated as cash flow hedges.

	Three Months Ended June 30,	
(Millions of dollars)	**2006**	**2005**
Revenues	$(26.2)	$ 68.5
Operating expenses:		
Energy costs	(6.8)	(54.7)
Operations and maintenance	1.4	(1.6)
Total unrealized gain (loss) on derivative contracts	$(31.6)	$ 12.2

The following table summarizes the changes in fair value of PacifiCorp's derivative contracts from March 31, 2006 to June 30, 2006, as well as the changes in fair value of those derivative contracts that have been recognized as a regulatory net asset (liability) because the contracts are receiving recovery in retail rates.

(Millions of dollars)	**Net Derivative Asset (Liability)**	**Regulatory Net Asset (Liability)**
Fair value of contracts outstanding at March 31, 2006	$ 7.9	$ 94.7
Contracts realized or otherwise settled during the period	(14.9)	(6.1)
Other changes in fair values (a)	1.7	(19.1)
Fair value of contracts outstanding at June 30, 2006	$ (5.3)	$ 69.5

(a) Other changes in fair values include the effects of changes in market prices, inflation rates and interest rates, including those based on models, on new and existing contracts.

The following table summarizes pre-tax changes in the fair value of derivative contracts:

	Three Months Ended June 30,	
(Millions of dollars)	2006	2005
Change in net derivative asset (liability)	$(13.2)	$66.1
Change in net derivative asset (liability) included in:		
Income from operations	$(31.6)	$12.2
Change in Regulatory net asset/liability	25.2	53.9
Other comprehensive loss	(6.8)	—
Change in net derivative asset (liability)	$(13.2)	$66.1

Table of Contents

Cash Flow Hedging

In order to reduce the impact of fluctuations in forward prices of electricity and natural gas on PacifiCorp's results of operations, PacifiCorp initiated cash flow hedging in April 2006 for a portion of its derivative contracts, primarily comprised of electricity sales and natural gas purchase contracts. Changes in the fair value of derivative contracts designated as cash flow hedges are recorded as other comprehensive income to the extent the hedge is effective in offsetting changes in future cash flows for forecasted electricity and natural gas purchase and sales transactions. Amounts included in other comprehensive income are reclassified to revenues or energy costs when the forecasted sale or purchase transaction affects earnings, or when it is probable that the forecasted transaction will not occur.

At June 30, 2006, PacifiCorp had cash flow hedges with expiration dates through December 2010. During the three months ended June 30, 2006, hedge ineffectiveness was insignificant and no component of the derivatives' gain or loss was excluded from the assessment of effectiveness. At June 30, 2006, $12.6 million of pre-tax net unrealized gains are forecasted to be reclassified from other comprehensive income into earnings over the next twelve months as contracts settle. However, the actual amount reclassified into earnings may vary from the amounts recorded as of June 30, 2006 due to future price changes. Hedge ineffectiveness and reclassifications from other comprehensive income to earnings are presented in Revenues for sales contracts and for contracts held for trading purposes and in Energy costs for purchase contracts and financial swaps.

Weather Derivatives

PacifiCorp estimates and records an asset or liability corresponding to the total expected future cash flows from its non-exchange traded streamflow weather derivative contract in accordance with Emerging Issues Task Force (''EITF'') No. 99-2, *Accounting for Weather Derivatives*. The net liability recorded for this contract was $9.3 million at June 30, 2006 and $2.1 million at March 31, 2006. PacifiCorp recognized a loss on this contract of $9.3 million for the three months ended June 30, 2006 and a loss on this contract of $12.2 million for the three months ended June 30, 2005.

Note 3 — Financing Arrangements

PacifiCorp amended and restated its existing $800.0 million committed bank revolving credit agreement in July 2006. Changes included the extension of the termination date from August 29, 2010 to July 6, 2011.

Note 4 — Commitments and Contingencies

PacifiCorp follows SFAS No. 5, *Accounting for Contingencies*, to determine accounting and disclosure requirements for contingencies. PacifiCorp operates in a highly regulated environment. Governmental bodies such as the Federal Energy Regulatory Commission (the ''FERC''), state regulatory commissions, the SEC, the Internal Revenue Service, the Department of Labor, the United States Environmental Protection Agency (the ''EPA'') and others have authority over various aspects of PacifiCorp's business operations and public reporting. Reserves are established when required, in management's judgment, and disclosures regarding litigation, assessments and creditworthiness of customers or counterparties, among others, are made when appropriate. The evaluation of these contingencies is performed by various specialists inside and outside of PacifiCorp.

From time to time, PacifiCorp is also a party to various legal claims, actions, complaints and disputes, certain of which involve material amounts. PacifiCorp has recorded $12.3 million in reserves as of June 30, 2006 related to various outstanding legal actions and disputes, excluding those discussed below. This amount represents PacifiCorp's best estimate of probable losses related to these matters. PacifiCorp currently believes that disposition of these matters will not have a material adverse effect on PacifiCorp's consolidated financial position, results of operations or liquidity.

Environmental Matters

PacifiCorp is subject to numerous environmental laws, including the Federal Clean Air Act and various state air quality laws; the Endangered Species Act, particularly as it relates to certain

Table of Contents

endangered species of fish; the Comprehensive Environmental Response, Compensation and Liability Act, and similar state laws relating to environmental cleanups; the Resource Conservation and Recovery Act and similar state laws relating to the storage and handling of hazardous materials; and the Clean Water Act, and similar state laws relating to water quality. These laws could potentially impact future operations. Environmental contingencies identified at June 30, 2006, principally consist of air quality matters. Pending or proposed air regulations would, if enacted, require PacifiCorp to reduce its electricity plant emissions of sulfur dioxide, nitrogen oxides and other pollutants below current levels. These reductions would be required to address regional haze programs, mercury emissions regulations and possible re-interpretations and changes to the federal Clean Air Act. In the future, PacifiCorp may incur significant costs to comply with various stricter air emissions requirements. These potential costs are expected to consist primarily of capital expenditures. PacifiCorp expects these costs would be included in rates and, as such, would not have a material adverse impact on PacifiCorp's consolidated financial position or results of operations. Environmental remediation liabilities recorded at June 30, 2006 totaled $40.1 million.

Hydroelectric Relicensing

PacifiCorp's hydroelectric portfolio consists of 51 plants with an aggregate plant net capability of 1,159.4 megawatts. The FERC regulates 93.9% of the installed capability of this portfolio through 18 individual licenses. Several of PacifiCorp's hydroelectric projects are in some stage of relicensing under the Federal Power Act. Hydroelectric relicensing and the related environmental compliance requirements are subject to uncertainties. PacifiCorp expects that future costs relating to these matters may be significant and consist primarily of additional relicensing costs, operations and maintenance expense and capital expenditures. Electricity generation reductions may result from the additional environmental requirements. PacifiCorp had incurred $73.5 million in costs as of June 30, 2006, for ongoing hydroelectric relicensing, which are reflected in Construction work-in-progress on the Condensed Consolidated Balance Sheet. PacifiCorp expects that these and future costs will be included in rates and, as such, will not have a material adverse impact on PacifiCorp's consolidated financial position or results of operations.

FERC Matters

California Refund Case – PacifiCorp is a party to a FERC proceeding that is investigating potential refunds for energy transactions in the California Independent System Operator and the California Power Exchange markets during past periods of high energy prices. PacifiCorp has a reserve of $17.7 million for these potential refunds. PacifiCorp's ultimate exposure to refunds is dependent upon any order issued by the FERC in this proceeding. In addition, beginning in summer 2000, California market conditions resulted in defaults of amounts due to PacifiCorp from certain counterparties resulting from transactions with the California Independent System Operator and California Power Exchange. PacifiCorp has reserved $5.0 million for these receivables.

FERC Market Power Analysis – Pursuant to the FERC's orders granting PacifiCorp authority to sell capacity and energy at market-based rates, PacifiCorp and certain of its former affiliates had been required to submit a joint market power analysis every three years. In February 2005, PacifiCorp submitted a joint triennial market power analysis, which indicated that PacifiCorp failed to pass one of the generation market power screens. In May 2005, the FERC issued an order instituting a proceeding pursuant to Section 206 of the Federal Power Act to determine whether PacifiCorp may continue to charge market-based rates for sales of wholesale energy and capacity. In June and July 2005, PacifiCorp and its formerly affiliated co-applicants submitted additional information and analysis to the FERC to rebut the presumption that PacifiCorp had generation market power. In January 2006, the FERC requested PacifiCorp to amend its previous filings with additional analysis, which was filed in March 2006. In June 2006, the FERC issued an order finding that PacifiCorp does not have market power and terminated the proceeding.

Note 5 — Common Shareholder's Equity

In June 2006, PacifiCorp received a capital contribution of $73.6 million in cash from its direct parent company, PPW Holdings LLC, a subsidiary of MEHC.

Table of Contents

Note 6 — Employee Benefits

The components of net periodic benefit cost for the three months ended June 30 are as follows:

(Millions of dollars)	Retirement Plans 2006	Retirement Plans 2005	Other Postretirement Benefits 2006	Other Postretirement Benefits 2005
Service cost	$ 7.5	$ 7.7	$ 2.3	$ 2.2
Interest cost	18.8	18.6	8.2	7.6
Expected return on plan assets (a)	(18.1)	(19.2)	(6.5)	(6.6)
Amortization of unrecognized net obligation	0.7	2.1	3.0	3.1
Amortization of unrecognized prior service cost	0.3	0.3	0.7	0.5
Amortization of unrecognized loss	6.7	5.4	1.5	0.7
Cost of termination benefits	0.3	—	—	—
Curtailment loss (b)	0.7	—	—	—
Net periodic benefit cost	$ 16.9	$ 14.9	$ 9.2	$ 7.5

(a) The market-related value of plan assets, among other factors, is used to determine expected return on plan assets and is calculated by spreading the difference between expected and actual investment returns over a five-year period beginning in the first year in which they occur.

(b) Represents the curtailment loss related to the Supplemental Executive Retirement Plan.

Employer Contributions

PacifiCorp contributed $75.4 million to its retirement plans and $0.1 million to its other postretirement benefit plans during the three months ended June 30, 2006. PacifiCorp expects to contribute another $5.3 million to its retirement plans and $27.4 million to its other postretirement benefit plan during the six months ending December 31, 2006.

Severance

PacifiCorp has undertaken a review of its organization and workforce. During the three months ended June 30, 2006, PacifiCorp incurred severance expense of $8.2 million under its severance and other benefit plans as a result of the review. During the three months ended June 30, 2005, PacifiCorp incurred $4.0 million of severance expense.

Note 7 — Comprehensive Income

The components of comprehensive income are as follows:

(Millions of dollars)	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005
Net income	$42.6	$46.4
Other comprehensive income:		
Unrealized loss on derivative contracts, net of tax of $(2.6)/2006	(4.2)	—
Unrealized loss on available-for-sale securities,net of tax of $(1.3)/2006 and $(0.4)/2005	(2.1)	(0.7)
Total comprehensive income	$36.3	$45.7

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
of PacifiCorp:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, common shareholder's equity and cash flows present fairly, in all material respects, the financial position of PacifiCorp and its subsidiaries at March 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended March 31, 2006, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements 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. An audit 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, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 3 to the consolidated financial statements, PacifiCorp and its subsidiaries changed the manner in which they apply the normal purchases and normal sales exception to derivative contracts entered into or modified after June 30, 2003, upon their adoption of SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*, as of July 1, 2003.

As discussed in Note 6 to the consolidated financial statements, PacifiCorp and its subsidiaries changed the manner in which they account for asset retirement obligations upon adoption of SFAS No. 143, A*ccounting for Asset Retirement Obligations*, as of April 1, 2003.

PricewaterhouseCoopers LLP
Portland, Oregon
May 26, 2006

Table of Contents

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

(Millions of dollars)	Years Ended March 31, 2006	2005	2004
Revenues	$3,896.7	$3,048.8	$3,194.5
Operating expenses:			
Energy costs	1,545.1	948.0	1,156.7
Operations and maintenance	1,014.5	913.1	895.8
Depreciation and amortization	448.3	436.9	428.8
Taxes, other than income taxes	96.8	94.4	95.3
Total	3,104.7	2,392.4	2,576.6
Income from operations	792.0	656.4	617.9
Interest expense and other (income) expense:			
Interest expense	279.9	267.4	256.5
Interest income	(9.5)	(9.1)	(13.8)
Interest capitalized	(32.4)	(14.8)	(19.9)
Minority interest and other	(6.1)	(7.3)	1.6
Total	231.9	236.2	224.4
Income from operations before income tax expense and cumulative effect of accounting change	560.1	420.2	393.5

Income tax expense	199.4	168.5	144.5
Income before cumulative effect of accounting change	360.7	251.7	249.0
Cumulative effect of accounting change (less applicable income tax benefit of $(0.6)/2004)	—	—	(0.9)
Net income	360.7	251.7	248.1
Preferred dividend requirement	(2.1)	(2.1)	(3.3)
Earnings on common stock	$ 358.6	$ 249.6	$ 244.8

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

Table of Contents

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

(Millions of dollars)	March 31,	
ASSETS	**2006**	**2005**
Current assets:		
Cash and cash equivalents	$ 119.6	$ 199.3
Accounts receivable less allowance for doubtful accounts of $11.4/2006 and $11.6/2005	266.8	293.0
Unbilled revenue	148.2	143.8
Amounts due from affiliates — ScottishPower	—	36.5
Inventories at average costs:		
Materials and supplies	131.2	114.7
Fuel	80.9	58.5
Current derivative contract asset	221.7	252.7
Other	46.9	115.8
Total current assets	1,015.3	1,214.3
Property, plant and equipment:		
Generation	5,686.3	5,238.7
Transmission	2,591.8	2,507.7
Distribution	4,502.8	4,308.7
Intangible plant	659.0	607.0
Other	1,662.5	1,596.9
Total operating assets	15,102.4	14,259.0
Accumulated depreciation and amortization	(5,611.5)	(5,361.8)
Net operating assets	9,490.9	8,897.2
Construction work-in-progress	618.3	593.4
Total property, plant and equipment, net	10,109.2	9,490.6
Other assets:		
Regulatory assets	884.3	972.8
Derivative contract regulatory asset	94.7	170.0
Non-current derivative contract asset	345.3	360.3
Deferred charges and other	282.5	312.9
Total other assets	1,606.8	1,816.0
Total assets	$12,731.3	$12,520.9

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

Table of Contents

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS, continued

(Millions of dollars)	March 31,	
LIABILITIES AND SHAREHOLDERS' EQUITY	**2006**	**2005**
Current liabilities:		
Accounts payable	$ 361.3	$ 350.4
Amounts due to affiliates — MidAmerican	3.8	—
Amounts due to affiliates — ScottishPower	—	3.9
Accrued employee expenses	118.0	134.3
Taxes payable	47.0	39.8
Interest payable	63.0	64.8
Current derivative contract liability	97.9	136.7
Current deferred tax liability	16.9	2.0
Long-term debt and capital lease obligations, currently maturing	216.9	269.9
Preferred stock subject to mandatory redemption, currently maturing	3.7	3.7
Notes payable and commercial paper	184.4	468.8
Other	103.2	123.4
Total current liabilities	1,216.1	1,597.7
Deferred credits:		
Deferred income taxes	1,621.2	1,629.0
Investment tax credits	67.6	75.6

Regulatory liabilities	804.7	806.0
Non-current derivative contract liability	461.2	630.5
Pension and other post employment liabilities	385.0	422.4
Other	361.4	304.8
Total deferred credits	3,701.1	3,868.3
Long-term debt and capital lease obligations, net of current maturities	3,721.0	3,629.0
Preferred stock subject to mandatory redemption, net of current maturities	41.3	48.8
Total liabilities	8,679.5	9,143.8
Commitments, contingencies and guarantees (See Notes 10 and 11)		
Shareholders' equity:		
Preferred stock	41.3	41.3
Common equity:		
Common shareholder's capital	3,381.9	2,894.1
Retained earnings	630.0	446.4
Accumulated other comprehensive income (loss):		
Unrealized gain on available-for-sale securities, net of tax of \$1.7/2006 and \$2.6/2005	2.7	4.3
Minimum pension liability, net of tax of \$(2.5)/2006 and \$(5.5)/2005	(4.1)	(9.0)
Total common equity	4,010.5	3,335.8
Total shareholders' equity	4,051.8	3,377.1
Total liabilities and shareholders' equity	\$12,731.3	\$12,520.9

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

Table of Contents

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

(Millions of dollars)	**Years Ended March 31,**		
	2006	**2005**	**2004**
Cash flows from operating activities:			
Net income	\$ 360.7	\$ 251.7	\$ 248.1
Adjustments to reconcile net income to net cash provided by operating activities:			
Cumulative effect of accounting change, net of tax	—	—	0.9
Unrealized gain on derivative contracts, net	(86.8)	(8.4)	(6.1)
Depreciation and amortization	448.3	436.9	428.8
Deferred income taxes and investment tax credits, net	13.9	120.0	80.5
Regulatory asset/liability establishment and amortization	51.6	66.7	111.1
Other	50.0	(27.0)	(6.5)
Changes in:			
Accounts receivable, prepayments and other current assets	71.1	(137.8)	(1.7)
Inventories	(38.9)	(16.2)	14.1
Amounts due to/from affiliates — MidAmerican, net	3.6	—	—
Amounts due to/from affiliates — ScottishPower, net	32.6	(32.8)	(36.8)
Accounts payable and accrued liabilities	(13.4)	84.1	(3.3)
Other	1.9	(26.1)	2.8
Net cash provided by operating activities	894.6	711.1	831.9
Cash flows from investing activities:			
Capital expenditures	(1,049.0)	(851.6)	(690.4)
Proceeds from sales of assets	1.3	7.1	3.3
Proceeds from available-for-sale securities	123.4	49.1	95.8
Purchases of available-for-sale securities	(84.9)	(44.7)	(89.4)
Other	(14.9)	(6.6)	(22.8)
Net cash used in investing activities	(1,024.1)	(846.7)	(703.5)
Cash flows from financing activities:			
Changes in short-term debt	(284.4)	343.9	99.9
Proceeds from long-term debt, net of issuance costs	296.0	395.2	396.7
Proceeds from issuance of common stock to PHI	484.7	—	—
Dividends paid	(177.1)	(195.4)	(165.1)
Repayments and redemptions of long-term debt	(269.7)	(259.8)	(194.1)
Repayment of preferred securities	—	—	(352.0)
Redemptions of preferred stock	(7.5)	(7.5)	(7.5)
Other	7.8	—	(0.3)
Net cash provided by (used in) financing activities	49.8	276.4	(222.4)
Change in cash and cash equivalents	(79.7)	140.8	(94.0)
Cash and cash equivalents at beginning of period	199.3	58.5	152.5
Cash and cash equivalents at end of period	\$ 119.6	\$ 199.3	\$ 58.5

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

Table of Contents

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY

(Millions of dollars, thousands of shares)	Common Shareholder's Capital		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Comprehensive Income (Loss)
	Shares	Amounts			
Balance at March 31, 2003	312,176	$2,892.1	$ 305.9	$ (3.6)	
Comprehensive income					
Net income	—	—	248.1	—	$ 248.1
Other comprehensive income (loss):					
Unrealized gain on available-for-sale securities, net of tax of $3.8	—	—	—	6.2	6.2
Minimum pension liability, net of tax of $(3.8)	—	—	—	(6.1)	(6.1)
Cash dividends declared:					
Preferred stock	—	—	(3.3)	—	
Common stock ($0.51 per share)	—	—	(160.6)	—	—
Balance at March 31, 2004	312,176	2,892.1	390.1	(3.5)	$ 248.2
Comprehensive income					
Net income	—	—	251.7	—	$ 251.7
Other comprehensive loss:					
Unrealized loss on available-for-sale securities, net of tax of $(0.1)	—	—	—	(0.2)	(0.2)
Minimum pension liability, net of tax of $(0.6)	—	—	—	(1.0)	(1.0)
Stock-based compensation expense	—	2.0	—	—	—
Cash dividends declared:					
Preferred stock	—	—	(2.1)	—	—
Common stock ($0.62 per share)	—	—	(193.3)	—	—
Balance at March 31, 2005	312,176	2,894.1	446.4	(4.7)	$ 250.5
Comprehensive income					
Net income	—	—	360.7	—	$ 360.7
Other comprehensive income (loss):					
Unrealized loss on available-for-sale securities, net of tax of $(0.9)	—	—	—	(1.6)	(1.6)
Minimum pension liability, net of tax of $3.0	—	—	—	4.9	4.9
Common stock issuance	44,885	484.7	—	—	—
Tax benefit from stock option exercises	—	7.5	—	—	—
Separation of employee benefit plans	—	(3.5)	—	—	—
Other	—	(0.9)	—	—	—
Cash dividends declared:					
Preferred stock	—	—	(2.1)	—	—
Common stock ($0.53 per share)	—	—	(175.0)	—	—
Balance at March 31, 2006	357,061	$3,381.9	$ 630.0	$ (1.4)	$ 364.0

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

Table of Contents

PACIFICORP AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1 — Summary of Significant Accounting Policies

On March 21, 2006, MidAmerican Energy Holdings Company (''MEHC'') completed its purchase of all of PacifiCorp's outstanding common stock from PacifiCorp Holdings, Inc. (''PHI''), a subsidiary of Scottish Power plc (''ScottishPower''), pursuant to the Stock Purchase Agreement among MEHC, ScottishPower and PHI dated May 23, 2005, as amended on March 21, 2006. The cash purchase price was $5.1 billion. PacifiCorp's common stock was directly acquired by a subsidiary of MEHC, PPW Holdings LLC. As a result of this transaction, MEHC controls the significant majority of PacifiCorp's voting securities, which includes both common and preferred stock. MEHC, a global energy company based in Des Moines, Iowa, is a majority-owned subsidiary of Berkshire Hathaway Inc.

Nature of operations – PacifiCorp (which includes PacifiCorp and its subsidiaries) is a United States electricity company serving retail customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp generates electricity and also engages in electricity sales and purchases on a wholesale basis. The subsidiaries of PacifiCorp support its electric utility operations by providing coal mining and other fuel-related services, as well as environmental remediation.

As a result of a settlement agreement between MEHC, the Utah Committee of Consumer Services and Utah Industrial Energy Consumers, MEHC contributed to

PacifiCorp, at no cost, MEHC's indirect 100.0% ownership interest in Intermountain Geothermal Company, which controls 69.3% of the steam rights associated with the geothermal field serving PacifiCorp's Blundell Geothermal Plant in Utah. Intermountain Geothermal Company therefore became a wholly owned subsidiary of PacifiCorp in March 2006, subsequent to the sale of PacifiCorp to MEHC.

Basis of presentation – The Consolidated Financial Statements of PacifiCorp include its integrated electric utility operations and its wholly owned and majority-owned subsidiaries. Intercompany transactions and balances have been eliminated upon consolidation.

Regulation – Accounting for the electric utility business conforms to accounting principles generally accepted in the United States as applied to regulated public utilities and as prescribed by agencies and the commissions of the various locations in which the electric utility business operates. PacifiCorp prepares its financial statements in accordance with Statement of Financial Accounting Standards (''SFAS'') No. 71, *Accounting for the Effects of Certain Types of Regulation* (''SFAS No. 71'') as further discussed in Note 2 — Accounting for the Effects of Regulation.

Use of estimates – The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities at the date of the financial statements. These estimates involve judgments with respect to numerous factors that are difficult to predict and are beyond management's control. As a result, actual results could differ materially from these estimates.

Reclassifications – Certain reclassifications of prior years' amounts have been made to conform to the fiscal 2006 method of presentation. These reclassifications had no effect on previously reported consolidated net income.

Cash and cash equivalents – For the purposes of these financial statements, PacifiCorp considers all liquid investments with maturities of three months or less, at the time of acquisition, to be cash equivalents.

Accounts receivable and allowance for doubtful accounts – Accounts receivable includes billed retail and wholesale services plus any accrued and unpaid interest. Credit is granted to customers, which include retail and wholesale customers, government agencies and other utilities. Management performs continuing credit evaluations of customers' financial conditions, and although PacifiCorp does not require collateral, deposits may be required from customers in certain circumstances.

Table of Contents

Accounts receivable are considered delinquent based on regulations provided by each state, which is generally if payment is not received by the date due, typically 30 days after the invoice date. PacifiCorp charges interest on delinquent customer accounts or past due balances in the states where PacifiCorp does business based on the respective regulation of each state, and this interest varies between 1.0% to 1.7% per month.

Management reviews accounts receivable on a monthly basis to determine if any receivable will potentially be uncollectible. The allowance for doubtful accounts includes amounts estimated through an evaluation of specific accounts, primarily for wholesale accounts receivable, and a reserve for retail accounts receivable based on historical experience. After all attempts to collect a receivable have failed or, if later, by six months from when a customer becomes inactive, the receivable is written-off against the allowance. Management believes that the allowance for doubtful accounts as of March 31, 2006 was adequate. However, actual write-offs could exceed the recorded allowance. The allowance activity was as follows:

	Years Ended March 31,		
(Millions of dollars)	**2006**	**2005**	**2004**
Beginning balance	$11.6	$ 23.3	$ 31.1
Charged to costs and expenses, net(a)	9.2	5.0	5.2
Write-offs, net(b)	(9.4)	(16.7)	(13.0)
Ending balance	$11.4	$ 11.6	$ 23.3

(a) Includes amounts charged to expense for adjustments to the allowance for doubtful accounts, net of recoveries of wholesale accounts receivable.

(b) Includes write-offs of retail and wholesale accounts receivable, net of recoveries of retail accounts receivable.

Inventories – Inventories are valued at the lower of average cost or market.

Property, plant and equipment – Property, plant and equipment are originally recorded at the cost of contracted services, direct labor and materials, interest capitalized during construction and indirect charges for engineering, supervision and similar overhead items. The cost of depreciable electric utility properties retired, less salvage value, is charged to accumulated depreciation. The cost of removal is charged against the regulatory liability established through depreciation rates. Annual overhaul costs for the replacement of defined retirement units are capitalized. Generally other costs of overhaul activities and other repairs and maintenance are expensed as they are incurred.

Intangible plant consists primarily of computer software costs that are originally recorded at cost. Accumulated amortization on Intangible plant was $329.8 million at March 31, 2006 and $307.6 million at March 31, 2005. Amortization expense on Intangible plant was $45.5 million for the year ended March 31, 2006 and $48.5 million for the year ended March 31, 2005. The estimated aggregate amortization on Intangible plant for the next five succeeding 12 month periods ending from March 31, 2007 to March 31, 2011 is $45.4 million, $38.9 million, $31.0 million, $24.7 million and $21.8 million. Unamortized computer software costs were $186.7 million at March 31, 2006 and $185.1 million at March 31, 2005.

Depreciation and amortization – The average depreciable lives of Property, plant and equipment currently in use by category are as follows:

Generation	
Steam plant	20 – 43 years

Hydroelectric plant	14 – 85 years
Other plant	15 – 35 years
Transmission	20 – 70 years
Distribution	44 – 50 years
Intangible plant	5 – 50 years
Other	5 – 30 years

Table of Contents

Computer software costs included in Intangible plant are initially assigned a depreciable life of 5 to 10 years.

During the year ended March 31, 2005, PacifiCorp changed the estimated average lives of certain computer software systems to reflect operational plans. This change reduced amortization expense by $12.9 million annually on existing computer software systems, with an annual impact to net income of approximately $8.0 million.

Depreciation and amortization are computed by the straight-line method either over the life prescribed by PacifiCorp's various regulatory jurisdictions for regulated assets or over the assets' estimated useful lives. Composite depreciation rates of average depreciable assets on utility Property, plant and equipment (excluding amortization of capital leases) were 3.0% for each of the years ended March 31, 2006, 2005 and 2004.

Asset impairments – Long-lived assets to be held and used by PacifiCorp are reviewed for impairment when events or circumstances indicate costs may not be recoverable. Such reviews are performed in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (''SFAS No. 144''). The impacts of regulation on cash flows are considered when determining impairment. Impairment losses on long-lived assets are recognized when book values exceed expected undiscounted future cash flows with the impairment measured on a discounted future cash flows basis.

Allowance for funds used during construction – The allowance for funds used during construction (the ''AFUDC'') represents the cost of debt and may also include equity funds used to finance utility property additions during construction. As prescribed by regulatory authorities, the AFUDC is capitalized as a part of the cost of utility property and is recorded in the Consolidated Statements of Income as Interest capitalized. Under regulatory rate practices, PacifiCorp is generally permitted to recover the AFUDC, and a fair return thereon, through its rate base after the related utility property is placed in service.

The composite capitalization rates were 6.5% for the year ended March 31, 2006; 4.5% for the year ended March 31, 2005; and 7.9% for the year ended March 31, 2004. PacifiCorp's AFUDC rates do not exceed the maximum allowable rates determined by regulatory authorities.

Derivatives – In accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, (''SFAS No. 133''), as amended by SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities*, and SFAS No. 149*, Amendment of Statement 133 on Derivative Instruments and Hedging Activities* (''SFAS No. 149'') (collectively ''SFAS No. 133''), derivative instruments are measured at fair value and recognized as either assets or liabilities on the Consolidated Balance Sheets, unless they qualify for the exemptions afforded by the standard. Changes in the fair value of derivatives are recognized in earnings during the period of change. Certain long-term derivative contracts have been approved by regulatory authorities for recovery through retail rates. Accordingly, changes in fair value of these contracts are deferred as regulatory assets or liabilities pursuant to SFAS No. 71. Derivative contracts for commodities used in PacifiCorp's normal business operation and that settle by physical delivery, among other criteria, are eligible for the normal purchases and normal sales exemption afforded by SFAS No. 133. These contracts are accounted for under accrual accounting and recorded in Revenues or Energy costs in the Consolidated Statements of Income when the contracts settle.

Marketable securities **–** PacifiCorp accounts for marketable securities, included in Deferred charges and other on PacifiCorp's Consolidated Balance Sheets, in accordance with SFAS No. 115, *Accounting for Certain Investments in Debt and Equity Securities.* PacifiCorp determines the appropriate classification of all marketable securities as held-to-maturity, available-for-sale or trading at the time of purchase and re-evaluates such classification as of each balance sheet date. As shown in Note 5 — Marketable Securities, at March 31, 2006 and 2005, all of PacifiCorp's investments in marketable securities were classified as available-for-sale and were reported at fair value. PacifiCorp uses the specific identification method in computing realized gains and losses on the sale of its available-for-sale securities. Realized gains and losses are included in Other (income) expense.

Table of Contents

Unrealized gains and losses are reported as a component of Accumulated other comprehensive income (loss). Investments that are in loss positions as of the end of each reporting period are analyzed to determine whether they have experienced a decline in market value that is considered other-than-temporary. An investment will generally be written down to market value if it has a significant unrealized loss for more than nine months. If additional information is available that indicates an investment is other-than-temporarily impaired, it will be written down prior to the nine-month time period. If an investment has been impaired for more than nine months but available information indicates that the impairment is temporary, the investment will not be written down.

Amounts held in trust – PacifiCorp holds certain trusts to fund decommissioning and reclamation activities as described in Note 5 — Marketable Securities and Note 6 — Asset Retirement Obligations and Accrued Environmental Costs. Amounts are also held in trusts that serve as funding vehicles for certain of PacifiCorp's employee benefits, including the Supplemental Executive Retirement Plan (the ''SERP'') as described in Note 17 — Employee Benefits.

Asset retirement obligations and accrued removal costs **–** Effective April 1, 2003, PacifiCorp recognizes the fair value of legal obligations associated with the retirement or removal of long-lived assets at the time the obligations are incurred and can be reasonably estimated in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations (*''SFAS No. 143''). The initial recognition of this liability is accompanied by a corresponding increase in Property, plant and equipment. Subsequent to the initial recognition, the 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 liability due to the passage of time. Additional depreciation expense is recorded prospectively for any Property, plant and equipment increases. In general, depreciation and accretion expense generated by SFAS No. 143 accounting is recorded as a regulatory asset or liability because such amounts are recoverable in rates. As of March 31, 2006, PacifiCorp adopted Financial Accounting Standards Board (the ''FASB'') Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations — an Interpretation of FASB Statement No. 143* (''FIN 47'') as described in Note 6 — Asset Retirement Obligations and Accrued Environmental Costs.

For those asset retirement removal costs that do not meet the requirements of SFAS No. 143, PacifiCorp recovers through approved depreciation rates estimated removal costs and accumulates such amounts in Asset retirement removal costs within Regulatory liabilities as described in Note 2 — Accounting for the Effects of Regulation.

Income taxes – PacifiCorp uses the liability method of accounting for deferred income taxes. Deferred tax liabilities and assets reflect the expected future tax consequences, based on enacted tax law, of temporary differences between the tax bases of assets and liabilities and their financial reporting amounts.

Prior to the sale of PacifiCorp to MEHC on March 21, 2006, PacifiCorp was a wholly owned subsidiary of PHI. Therefore, it was included in the consolidated income tax return for PHI from April 1, 2003 through March 21, 2006. PacifiCorp currently is an indirect, majority-owned subsidiary of Berkshire Hathaway Inc. and is included in its consolidated income tax return. PacifiCorp's provision for income taxes has been computed on the basis that it files separate consolidated income tax returns with its subsidiaries.

Historically, PacifiCorp did not recognize deferred taxes on many of the timing differences between book and tax depreciation. In prior years, these benefits were flowed through to the utility customer as prescribed by PacifiCorp's various regulatory jurisdictions. Deferred income tax liabilities and Regulatory assets have been established for those flow-through tax benefits as shown in Note 2 — Accounting for the Effects of Regulation since PacifiCorp is allowed to recover the increased income tax expense when these differences reverse.

Investment tax credits are deferred and amortized to income over periods prescribed by PacifiCorp's various regulatory jurisdictions.

PacifiCorp establishes accruals for certain tax contingencies when, despite the belief that its tax return positions are supported, it also believes that certain positions may be challenged and that it is

Table of Contents

probable those positions may not be fully sustained. PacifiCorp is under continuous examination by the Internal Revenue Service and other tax authorities and accounts for potential losses of tax benefits in accordance with SFAS No. 5, *Accounting for Contingencies* (''SFAS No. 5''). See Note 19 — Income Taxes for further information.

Stock-based compensation – As permitted by SFAS No. 123, *Accounting for Stock-Based Compensation (*''SFAS No. 123''), PacifiCorp accounts for its stock-based compensation arrangements, primarily employee stock options, under the intrinsic value recognition and measurement principles of Accounting Principles Board (''APB'') Opinion No. 25, *Accounting for Stock Issued to Employees* (''APB No. 25''), and related interpretations in accounting for employee stock options issued to PacifiCorp employees. Under APB No. 25, because the exercise price of employee stock options equals the market price of the underlying stock on the date of grant, no compensation expense is recorded if the ultimate number of shares to be awarded is known at the date of the grant. All options currently accounted for under APB No. 25 were issued in ScottishPower American Depository Shares, as discussed in Note 18 — Stock-Based Compensation. Had PacifiCorp determined compensation cost based on the fair value at the grant date for all stock options vesting in each period under SFAS No. 123, PacifiCorp's Net income would have been reduced to the pro forma amounts below:

	Years Ended March 31,		
(Millions of dollars)	**2006**	**2005**	**2004**
Net income as reported	$360.7	$251.7	$248.1
Add: stock-based compensation included in reported net income, net of related tax effects	0.1	3.1	—
Less: stock-based compensation expense using the fair value method, net of related tax effects	(1.4)	(4.3)	(1.1)
Pro forma net income	$359.4	$250.5	$247.0

Revenue recognition **–** Revenue is recognized upon delivery for retail and wholesale electricity sales. Electricity sales to retail customers are determined based on meter readings taken throughout the month. PacifiCorp accrues an estimate of unbilled revenues, which are earned but not yet billed, net of estimated line losses, each month for electric service provided after the meter reading date to the end of the month. The process of calculating the Unbilled revenue estimate consists of three components: quantifying PacifiCorp's total electricity delivered during the month, assigning Unbilled revenues to customer type and valuing the unbilled energy. Factors involved in the estimation of consumption and line losses relate to weather conditions, amount of natural light, historical trends, economic impacts and customer type. Valuation of unbilled energy is based on estimating the average price for the month for each customer type. The amount accrued for Unbilled revenues was $148.2 million at March 31, 2006 and $143.8 million at March 31, 2005.

Segment information **–** PacifiCorp currently has one segment, which includes the regulated retail and wholesale electric operations.

New accounting standards –

SFAS No. 123R

On April 1, 2006, PacifiCorp adopted SFAS No. 123R, *Share-Based Payment* (''SFAS No. 123R''), a revision of the originally issued SFAS No. 123. SFAS No. 123R establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services. SFAS No. 123R requires that the cost resulting from all share-based payment transactions be recognized in the financial statements using the fair value method. The intrinsic value method of accounting established by APB No. 25 will no longer be allowed. The adoption of SFAS No. 123R did not have an effect on PacifiCorp's financial position or results of operations as all requisite service has been rendered by employees and the outstanding stock awards are fully vested. For further information see Note 18 — Stock-Based Compensation.

Table of Contents

EITF No. 04-6

On April 1, 2006, PacifiCorp adopted Emerging Issues Task Force No. 04-6, *Accounting for Stripping Costs Incurred during Production in the Mining Industry* (''EITF No. 04-6''). EITF No. 04-6 requires that stripping costs incurred during the production phase of a mine are variable production costs that should be included in the costs of the inventory produced (that is, extracted) during the period that the stripping costs are incurred. The adoption of EITF No. 04-6 did not have a material impact on PacifiCorp's consolidated financial position or results of operations.

Note 2 — Accounting for the Effects of Regulation

Regulated utilities have historically applied the provisions of SFAS No. 71, which is based on the premise that regulators will set rates that allow for the recovery of a utility's costs, including cost of capital. Accounting under SFAS No. 71 is appropriate as long as (i) rates are established by or subject to approval by independent, third-party regulators, (ii) rates are designed to recover the specific enterprise's cost of service, and (iii) in view of demand for service, it is reasonable to assume that rates are set at levels that will recover costs and can be collected from customers.

SFAS No. 71 provides that regulatory assets may be capitalized if it is probable that future revenue in an amount at least equal to the capitalized costs will result from their treatment as allowable costs for rate-making purposes. In addition, the rate action should permit recovery of the specific previously incurred costs rather than provide for expected levels of similar future costs. PacifiCorp records regulatory assets and liabilities based on management's assessment that it is probable that a cost will be recovered (asset) or that an obligation has been incurred (liability). The final outcome, or additional regulatory actions, could change management's assessment in future periods. A regulator can provide current rates intended to recover costs that are expected to be incurred in the future, with the understanding that if those costs are not incurred, future rates will be reduced by corresponding amounts. If current rates are intended to recover such costs, PacifiCorp recognizes amounts charged pursuant to such rates as liabilities and takes those amounts to income only when the associated costs are incurred. In applying SFAS No. 71, PacifiCorp must give consideration to changes in the level of demand or competition during the cost recovery period. In accordance with SFAS No. 71, PacifiCorp capitalizes certain costs as regulatory assets if authorized to recover the costs in future periods.

PacifiCorp continuously evaluates the appropriateness of applying SFAS No. 71 to each of its jurisdictions. At March 31, 2006, PacifiCorp had recorded specifically identified net regulatory assets of $174.3 million. In the event PacifiCorp stopped applying SFAS No. 71 at March 31, 2006, an after-tax loss of approximately $108.2 million would be recognized.

PacifiCorp is subject to the jurisdiction of public utility regulatory authorities of each of the states in which it conducts retail electric operations with respect to prices, services, accounting, issuance of securities and other matters. The jurisdictions in which PacifiCorp operates are in various stages of evaluating deregulation. At present, PacifiCorp is subject to cost-based rate-making for its business. PacifiCorp is a ''licensee'' and a ''public utility'' as those terms are used in the Federal Power Act and is, therefore, subject to regulation by the Federal Energy Regulatory Commission (the ''FERC'') as to accounting policies and practices, certain prices and other matters.

Table of Contents

Regulatory assets include the following:

	March 31,	
(Millions of dollars)	**2006(a)**	**2005(a)**
Deferred income taxes(b)	$480.3	$ 499.9
Minimum pension liability(c)	257.7	280.7
Unamortized issuance expense on retired debt	29.0	34.6
Demand-side resource costs	13.4	25.5
Transition plan — retirement and severance	16.9	24.9
Various other costs	87.0	107.2
Subtotal	884.3	972.8
Derivative contracts(d)	94.7	170.0
Total	$979.0	$1,142.8

(a) PacifiCorp had regulatory assets not accruing carrying charges of $952.9 million at March 31, 2006 and $1,095.6 million at March 31, 2005.

(b) Represents accelerated income tax benefits previously passed on to ratepayers that will be included in rates concurrently with recognition of the associated income tax expense.

(c) Represents minimum pension liability offsets proportionate to the amount of pension costs that are recoverable in rates. Remaining minimum pension liability offsets are included net of tax in Accumulated other comprehensive income (loss).

(d) Represents net unrealized losses related to derivative contracts included in rates. See Note 3 — Derivative Instruments for further information.

Regulatory liabilities include the following:

(Millions of dollars)	March 31, 2006	2005
Asset retirement removal costs(a)	$699.8	$692.1
Deferred income taxes	43.7	44.4
Bonneville Power Administration Regional Exchange Program	23.3	12.6
Various other costs	37.9	56.9
Total	$804.7	$806.0

(a) Represents removal costs recovered in rates.

PacifiCorp evaluates the recovery of all regulatory assets periodically and as events occur. The evaluation includes the probability of recovery, as well as changes in the regulatory environment. Regulatory and/or legislative action in Utah, Oregon, Wyoming, Washington, Idaho and California may require PacifiCorp to record regulatory asset write-offs and charges for impairment of long-lived assets in future periods. Impairment would be measured in accordance with PacifiCorp's asset impairment policy, as discussed in Note 1 — Summary of Significant Accounting Policies.

Note 3 — Derivative Instruments

In accordance with SFAS No. 133, PacifiCorp records derivative instruments on the Consolidated Balance Sheets as assets or liabilities measured at estimated fair value, unless they qualify for the exemptions afforded by the standard. PacifiCorp uses derivative instruments (primarily forward purchases and sales) to manage the commodity price risk inherent in its fuel and electricity obligations, as well as to optimize the value of power generation assets and related contracts.

In July 2003, the EITF issued EITF No. 03-11, *Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not ''Held for Trading Purposes'' as*

Table of Contents

defined in Issue No. 02-3 (''EITF No. 03-11''), which provides guidance on whether to report realized gains or losses on physically settled derivative contracts not held for trading purposes on a gross or net basis and requires realized gains or losses on derivative contracts that do not settle physically to be reported on a net basis. The adoption of EITF No. 03-11 during the year ended March 31, 2004 resulted in PacifiCorp netting certain contracts that were previously recorded on a gross basis in Wholesale sales and other revenues and Energy costs in the Consolidated Statements of Income. The adoption of EITF No. 03-11 had no impact on PacifiCorp's consolidated Net income and all periods presented are consistent with the requirements of EITF 03-11.

As the FASB continues to issue interpretations, PacifiCorp may change the conclusions that it has reached and, as a result, the accounting treatment and financial statement impact could change in the future.

The accounting treatment for the various classifications of derivative financial instruments is as follows:

Normal purchases and normal sales – The contracts that qualify as normal purchases and normal sales are excluded from the requirements of SFAS No. 133. The realized gains and losses on these contracts are reflected in the Consolidated Statements of Income at the contract settlement date.

Undesignated – Unrealized gains and losses on derivative contracts held for trading purposes are presented on a net basis in the Consolidated Statements of Income as Revenues. Unrealized gains and losses on derivative contracts not held for trading purposes are presented in the Consolidated Statements of Income as Revenues for sales contracts and as Energy costs and Operations and maintenance expense for purchase contracts and financial swaps.

PacifiCorp has the following types of commodity transactions:

Wholesale electricity purchase and sales contracts – PacifiCorp makes continuing projections of future retail and wholesale loads and future resource availability to meet these loads based on a number of criteria, including historical load and forward market and other economic information and experience. Based on these projections, PacifiCorp purchases and sells electricity on a forward yearly, quarterly, monthly, daily and hourly basis to match actual resources to actual energy requirements and sells any surplus at the prevailing market price. This process involves hedging transactions, which include the purchase and sale of firm energy under long-term contracts, forward physical contracts or financial contracts for the purchase and sale of a specified amount of energy at a specified price over a given period of time.

Natural gas and other fuel purchase contracts – PacifiCorp manages its natural gas supply requirements by entering into forward commitments for physical delivery of natural gas. PacifiCorp also manages its exposure to increases in natural gas supply costs through forward commitments for the purchase of physical natural gas at fixed prices and financial swap contracts that settle in cash based on the difference between a fixed price that PacifiCorp pays and a floating market-based price that PacifiCorp receives.

Where PacifiCorp's derivative instruments are subject to a master netting agreement and the criteria of FIN 39, *Offsetting of Amounts Related to Certain Contracts- An Interpretation of APB Opinion No. 10 and FASB Statement No. 105*, are met, PacifiCorp presents its derivative assets and liabilities, as well as accompanying receivables and payables, on a net basis in the accompanying Consolidated Balance Sheets.

Unrealized gains and losses on energy sales and purchase contracts are affected by fluctuations in forward prices for electricity and natural gas. The following table summarizes the amount of the pre-tax unrealized gains and losses included within the Consolidated Statements of Income associated with changes in the fair value of PacifiCorp's derivative contracts that are not included in rates.

Table of Contents

(Millions of dollars)	Years Ended March 31, 2006	2005	2004
Revenues	$ 224.4	$(330.0)	$(29.4)
Operating expenses:			
Energy costs	(131.1)	338.4	35.5
Operations and maintenance	(6.5)	—	—
Total unrealized gain on derivative contracts	$ 86.8	$ 8.4	$ 6.1

The following table shows the changes in the fair value of energy-related contracts subject to the requirements of SFAS No. 133, as amended, from April 1, 2005 to March 31, 2006.

(Millions of dollars)	Net Asset (Liability) Trading	Non-trading	Regulatory Net Asset (Liability) (b)
Fair value of contracts outstanding at March 31, 2005	$ 0.2	$(154.4)	$ 170.0
Contracts realized or otherwise settled during the period	(0.2)	(115.8)	128.3
Other changes in fair values(a)	0.2	277.9	(203.6)
Fair value of contracts outstanding at March 31, 2006	$ 0.2	$ 7.7	$ 94.7

(a) Other changes in fair values include the effects of changes in market prices, inflation rates and interest rates,including those based on models, on new and existing contracts.

(b) Net unrealized losses (gains) related to derivative contracts included in rates are recorded as a regulatory net asset (liability).

PacifiCorp bases its forward price curves upon market price quotations when available and bases them on internally developed and commercial models, with internal and external fundamental data inputs, when market quotations are unavailable. Market quotes are obtained from independent energy brokers, as well as direct information received from third-party offers and actual transactions executed by PacifiCorp. Price quotations for certain major electricity trading hubs are generally readily obtainable for the first six years and therefore PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. However, in the later years or for locations that are not actively traded, forward price curves must be developed. For short-term contracts at less actively traded locations, prices are modeled based on observed historical price relationships with actively traded locations. For long-term contracts extending beyond six years, the forward price curve (beyond the first six years) is based upon the use of a fundamentals model (cost-to-build approach) due to the limited information available. The fundamentals model is updated as warranted, at least quarterly, to reflect changes in the market such as long-term natural gas prices and expected inflation rates.

Short-term contracts, without explicit or embedded optionality, are valued based upon the relevant portion of the forward price curve. Contracts with explicit or embedded optionality are valued by separating each contract into its physical and financial forward, swap and option components. Forward and swap components are valued against the appropriate forward price curve. The optionality is valued using a modified Black-Scholes model approach or a stochastic simulation (Monte Carlo) approach. Each option component is modeled and valued separately using the appropriate forward price curve.

Standardized derivative contracts that are valued using market quotations, as described above, are classified in the table below as ''values based on quoted market prices from third-party sources.'' All remaining contracts, which include non-standard contracts and contracts for which market prices are not routinely quoted, are classified as ''values based on models and other valuation methods.''

Table of Contents

(Millions of dollars)	Fair Value of Contracts at Period-End: Maturity Less Than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in Excess of 5 Years	Total Fair Value
Trading:					
Values based on quoted market prices from third-party sources	$ 0.2	$ —	$ —	$ —	$ 0.2
Non-trading:					
Values based on quoted market prices from third-party sources	$ 58.7	$ 49.7	$ 6.0	$ 1.2	$ 115.6
Values based on models and other valuation methods	64.9	82.9	4.9	(260.6)	(107.9)
Total non-trading	$123.6	$132.6	$10.9	$(259.4)	$ 7.7
Regulatory net asset (liability)	$ (76.2)	$ (83.4)	$ (5.5)	$ 259.8	$ 94.7

Weather derivatives – PacifiCorp currently has a non-exchange traded streamflow weather derivative contract to reduce PacifiCorp's exposure to variability in weather conditions that affect hydroelectric generation. Under the agreement, PacifiCorp pays an annual premium in return for the right to make or receive payments if streamflow levels are above or below certain thresholds. PacifiCorp estimates and records an asset or liability corresponding to the total expected future cash flow under the contract in accordance with EITF No. 99-2, *Accounting for Weather Derivatives*. The net asset (liability) recorded for this contract was $(2.1) million at March 31, 2006 and $20.3 million at March 31, 2005 and was included in other current assets (liabilities) in the Consolidated Balance Sheets. PacifiCorp recognized a loss of $15.6 million for the year ended March 31, 2006; a gain of $27.9 million for the year ended March 31, 2005; and a gain of $0.4 million for the year ended March 31, 2004.

Note 4 — Related-Party Transactions

Transactions while owned by MEHC – As discussed in Note 1 — Summary of Significant Accounting Policies, PacifiCorp was acquired by MEHC on March 21, 2006. The following describes PacifiCorp's transactions and balances with unconsolidated related parties while owned by MEHC.

PacifiCorp began participating in a captive insurance program provided by MEHC Insurance Services Ltd. (''MISL''), a wholly owned subsidiary of MEHC. MISL covers all or significant portions of the property damage and liability insurance deductibles in many of PacifiCorp's current policies, as well as overhead distribution and transmission line property damage. PacifiCorp has no equity interest in MISL and has no obligation to contribute equity or loan funds to MISL. Premium amounts are established based on a combination of actuarial assessments and market rates to cover loss claims, administrative expenses and appropriate reserves. Certain costs associated with the program are prepaid and amortized over the policy coverage period expiring March 20, 2007. Prepayments to MISL were $7.2 million at March 31, 2006. Premium expenses were $0.2 million for March 21, 2006 through March 31, 2006.

As of March 31, 2006, Amounts due to affiliates — MEHC included $3.8 million of current income taxes payable to PPW Holdings LLC.

See Note 1 — Summary of Significant Accounting Policies for information related to the transfer of MEHC's 100.0% ownership interest in Intermountain Geothermal Company to PacifiCorp.

Transactions while owned by ScottishPower – There were no loans or advances between PacifiCorp and ScottishPower or between PacifiCorp and PHI. Loans from PacifiCorp to ScottishPower or PHI were prohibited under the Public Utility Holding Company Act of 1935 (''PUHCA''), which was repealed effective February 2006. Loans from ScottishPower or PHI to PacifiCorp generally required state regulatory and SEC approval. There were intercompany loan agreements that allowed funds to be lent to PacifiCorp from PacifiCorp Group Holdings Company (''PGHC''), but loans from

PacifiCorp to PGHC were prohibited. There were intercompany loan agreements that allowed funds to be lent between PacifiCorp and Pacific Minerals, Inc., a wholly owned subsidiary of PacifiCorp. PacifiCorp does not maintain a centralized cash or money pool. Therefore, funds of each company were not commingled with funds of any other company.

The tables below detail PacifiCorp's transactions and balances with unconsolidated related parties while owned by ScottishPower.

(Millions of dollars)	March 31, 2006*	March 31, 2005
Amounts due from former affiliated entities:		
SPUK(a)	$ —	$ 0.3
PHI and its subsidiaries(b)	—	36.2
	$ —	$36.5
Prepayments to former affiliated entities:		
PHI and its subsidiaries(c)	$ —	$ 1.5
Amounts due to former affiliated entities:		
SPUK(d)	$ —	$ 3.9
Deposits received from former affiliated entities:		
PHI and its subsidiaries(e)	$ —	$ 0.3

(Millions of dollars)	Years Ended March 31, 2006	2005	2004
Revenues from former affiliated entities:			
PHI and its subsidiaries(e)	$ 7.8	$ 5.9	$ 4.4
Expenses recharged to former affiliated entities:			
SPUK(a)	$ 6.2	$ 3.0	$ 0.7
PHI and its subsidiaries(b)	7.3	9.4	8.0
	$13.5	$12.4	$ 8.7
Expenses incurred from former affiliated entities:			
SPUK(d)	$18.6	$18.3	$ 7.8
PHI and its subsidiaries(c)	19.3	17.3	17.0
DIIL(f)	7.0	—	—
	$44.9	$35.6	$24.8
Interest expense to former affiliated entities:			
PHI and its subsidiaries(g)	$ —	$ 0.1	$ 0.2

* Amounts settled at close of sale to MEHC.

(a) For the years ended March 31, 2006 and 2005, receivables and expenses included amounts allocated to Scottish Power UK plc (''SPUK''), an indirect subsidiary of ScottishPower, by PacifiCorp for administrative services provided under ScottishPower's affiliated interest cross-charge policy. For the year ended March 31, 2006, expenses also included costs associated with retention agreements and severance benefits reimbursed by SPUK. In addition, PacifiCorp recharged to SPUK payroll costs and related benefits of PacifiCorp employees working on international assignment in the United Kingdom for ScottishPower during the years ended March 31, 2006, 2005 and 2004.

(b) Amounts shown pertain to activities of PacifiCorp with its former parent PHI and its subsidiaries. Expenses recharged reflect costs for support services to PHI and its subsidiaries. Amounts due from PHI and its subsidiaries included $33.8 million as of March 31, 2005 of income taxes receivable from PHI. PHI was the tax-paying entity while PacifiCorp was owned by ScottishPower.

(c) These expenses primarily related to operating lease payments for the West Valley facility, located in Utah and owned by West Valley Leasing Company, LLC (''West Valley''). West Valley is a subsidiary of PPM Energy, Inc. (''PPM''), which is a subsidiary of PHI. The lease is a 15 year operating lease on an electric generation facility. The facility consists of five generating units each with a nameplate rating of 43.4 MW. Certain costs associated with the West Valley lease are prepaid on an annual basis. Lease expense was $16.4 million for the year ended March 31, 2006; $17.1 million for the year ended March 31, 2005; and $17.0 million for the year ended March 31, 2004. PacifiCorp has an option to terminate the West Valley lease if written notice is provided to West Valley on or before December 1, 2006. If the option to terminate is exercised, the lease would terminate in May 2008. PacifiCorp is committed to future minimum lease payments of $10.0 million annually for each of the 12 months ending March 31, 2007 and 2008 and $1.7 million for the two months ending May 31, 2008. These minimum future lease payments reflect the reduction in monthly payments resulting from a March 2006 amendment to the lease terms.

(d) These liabilities and expenses primarily represented amounts allocated to PacifiCorp by SPUK for administrative services received under the cross-charge policy. Cross-charges from SPUK to PacifiCorp amounted to $16.7 million for the year ended March 31, 2006 and $14.9 million for the year ended March 31, 2005. These costs were recorded in Operations and maintenance expense. SPUK also recharged PacifiCorp for payroll costs and related benefits of SPUK employees working on international assignment with PacifiCorp in the United States.

(e) These revenues and the associated deposits related to wheeling services billed to PPM. PacifiCorp provided these services to PPM pursuant to PacifiCorp's FERC-approved open access transmission tariff, which required PacifiCorp to make transmission services available on a non-discriminatory basis to all interested parties.

(f) PacifiCorp began participating in a captive insurance program provided by Dornoch International Insurance Limited (''DIIL''), an indirect wholly owned consolidated subsidiary of ScottishPower, in May 2005. DIIL covered all or significant portions of the property damage and liability insurance deductibles in many of PacifiCorp's policies, as well as overhead distribution and transmission line property damage. PacifiCorp had no equity interest in DIIL and had no obligation to contribute equity or loan funds to DIIL. Premium amounts were established to cover loss claims, administrative expenses and appropriate reserves, but otherwise DIIL was not operated to generate profits.

(g) Included interest on short-term demand loans made to PacifiCorp by PGHC, in accordance with regulatory authorization.

Note 5 — Marketable Securities

PacifiCorp, by contract with Idaho Power, the minority owner of Bridger Coal Company (an indirect subsidiary of PacifiCorp), maintains a trust relating to final reclamation of a leased coal mining property. Amounts funded are based on estimated future reclamation costs and estimated future coal deliveries. Trust fund assets associated with Bridger Coal Company recorded at fair value included in Deferred charges and other were $101.9 million at March 31, 2006 and $92.4 million at March 31, 2005, including the Idaho Power minority-interest portion. Minority interest in Bridger Coal Company was $49.5 million at March 31, 2006 and $26.2 million at March 31, 2005. See also Note 6 — Asset Retirement Obligations and Accrued Environmental Costs.

The amortized cost and fair value of reclamation trust securities and other investments included in Deferred charges and other on PacifiCorp's Consolidated Balance Sheets, which are classified as available-for-sale, were as follows:

(Millions of dollars)	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
March 31, 2006				
Debt securities	$ 25.9	$ 0.2	$ (0.6)	$ 25.5
Equity securities	61.7	7.0	(0.7)	68.0
Total	$ 87.6	$ 7.2	$ (1.3)	$ 93.5
March 31, 2005				
Mutual fund account(a)	$ 27.0	$ —	$ (1.0)	$ 26.0
Debt securities	25.6	0.4	(0.4)	25.6
Equity securities	60.6	13.2	(1.2)	72.6
Total	$113.2	$13.6	$ (2.6)	$124.2

(a) In October 2005, the mutual fund account was transferred to a money market account.

The quoted market price of securities is used to estimate their fair value.

The amortized cost and estimated fair value of debt securities at March 31, 2006 and 2005 by contractual maturities and of equity securities for the same dates are shown below. Actual maturities may differ from contractual maturities because borrowers may have the right to call or prepay obligations with or without call or prepayment penalties.

	March 31,			
	2006		2005	
(Millions of dollars)	Amortized Cost	Estimated Fair Value	Amortized Cost	Estimated Fair Value
Debt securities				
Due in one year or less	$ 0.7	$ 0.6	$ 0.7	$ 0.7
Due after one year through five years	6.5	6.4	5.6	5.6
Due after five years through ten years	9.9	9.8	9.8	9.9
Due after ten years	8.8	8.7	9.5	9.4
Mutual fund account	—	—	27.0	26.0
Equity securities	61.7	68.0	60.6	72.6

Total	$87.6	$93.5	$113.2	$124.2

Proceeds, gross gains and gross losses from realized sales of available-for-sale securities using the specific identification method were as follows for the years ended March 31, 2006, 2005 and 2004:

	Years Ended March 31,		
(Millions of dollars)	2006	2005	2004
Proceeds	$123.4	$49.1	$95.8
Gross gains	$ 16.6	$ 6.3	$ 6.5
Gross losses	(2.3)	(2.2)	(3.4)
Net gains	14.3	4.1	3.1
Less net gains included in Regulatory liabilities(a)	(16.6)	(5.6)	(3.2)
Net losses included in Net income	$ (2.3)	$ (1.5)	$ (0.1)

(a) Realized gains and losses on the Bridger Coal Company reclamation trust described above are recorded as a regulatory liability in accordance with the prescribed regulatory treatment.

Table of Contents

Note 6 — Asset Retirement Obligations and Accrued Environmental Costs

Asset Retirement Obligations – PacifiCorp records asset retirement obligations for long-lived physical assets that qualify as legal obligations under SFAS No. 143. PacifiCorp estimates its asset retirement obligation 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. PacifiCorp then records an asset retirement obligation asset associated with the liability. The asset retirement obligation assets are depreciated over their expected lives and the asset retirement obligation liabilities are accreted to the projected spending date. Changes in estimates could occur due to plan revisions, changes in estimated costs and changes in timing of the performance of reclamation activities. In addition, PacifiCorp records removal costs as a part of depreciation expense in accordance with regulatory accounting requirements described in Note 2 — Accounting for the Effects of Regulation. Since asset retirement costs are recovered through the ratemaking process, PacifiCorp records a regulatory asset or regulatory liability on the Consolidated Balance Sheets to account for the difference between asset retirement costs as currently approved in rates and costs under SFAS No. 143.

PacifiCorp does not recognize liabilities for asset retirement obligations for which the fair value cannot be reasonably estimated. PacifiCorp has asset retirement obligations associated with its transmission and distribution systems and certain coal mines. However, due to the indeterminate removal date, the fair value of the associated liabilities currently cannot be estimated and no amounts are recognized in the Consolidated Financial Statements.

In March 2005, the FASB issued FIN 47. FIN 47 clarifies that an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation when incurred if the fair value of the liability can be reasonably estimated. Upon adoption of FIN 47 at March 31, 2006, PacifiCorp recorded an asset retirement obligation liability at a net present value of $22.7 million. PacifiCorp also increased net depreciable assets by $1.8 million, reclassified $13.5 million of costs accrued for retirement removals from regulatory liabilities to asset retirement obligation liabilities, increased regulatory liabilities by $0.4 million and increased regulatory assets by $7.8 million for the difference between retirement costs approved by regulators and obligations under FIN 47.

The pro forma total asset retirement obligation liability balances that would have been reported assuming FIN 47 had been adopted on April 1, 2004, rather than March 31, 2006, are as follows:

(Millions of dollars)	
Pro forma asset retirement obligation liability at April 1, 2004	$215.8
Pro forma asset retirement obligation liability at March 31, 2005	$222.1

Due to regulatory accounting treatment, the adoption of FIN 47 would have no material impact on net income for the pro forma periods listed above and had no impact on PacifiCorp's reported cash flows.

The following table describes the changes to PacifiCorp's asset retirement obligation liability for the years ended March 31, 2006 and 2005:

(Millions of dollars)	March 31, 2006	March 31, 2005
Liability recognized at beginning of period	$199.6	$193.5
Liabilities incurred(a)	25.2	1.4
Liabilities settled(b)	(10.4)	(13.0)
Revisions in cash flow(c)	(11.2)	8.9
Accretion expense	8.9	8.8
Asset retirement obligation	212.1	199.6
Less current portion(d)	7.0	17.8
Long-term asset retirement obligation at end of period(e)	$205.1	$181.8

(a) Relates primarily to the adoption of FIN 47 at March 31, 2006.

(b) Relates primarily to ongoing reclamation work at the Glenrock coal mine.

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

(d) Amount included in Other current liabilities on the Consolidated Balance Sheets.

(e) Amount included in Deferred credits — other on the Consolidated Balance Sheets.

PacifiCorp had trust fund assets recorded at fair value included in Deferred charges and other of $103.0 million at March 31, 2006 and $93.4 million at March 31, 2005 relating to mine and plant reclamation, including the minority-interest joint-owner portions.

Accrued Environmental Costs – PacifiCorp's policy is to accrue environmental cleanup-related costs of a non-capital nature when those costs are believed to be probable and can be reasonably estimated. The quantification of environmental exposures is based on assessments of many factors, including changing laws and regulations, advancements in environmental technologies, the quality of information available related to specific sites, the assessment stage of each site investigation, preliminary findings and the length of time involved in remediation or settlement. PacifiCorp hires external consultants from time to time to conduct studies in order to establish reserves for various site environmental remediation costs. PacifiCorp is subject to cost-sharing agreements with other potentially responsible parties based on decrees, orders and other legal agreements. In these circumstances, PacifiCorp assesses the financial capability of other potentially responsible parties and the reasonableness of PacifiCorp's apportionment. These agreements may affect the range of potential loss. Additionally, PacifiCorp may benefit from excess insurance policies that may cover some of the cleanup costs if costs incurred exceed certain amounts.

PacifiCorp assesses its potential obligations to perform environmental remediation on an ongoing basis. As a result of studies performed during the year ended March 31, 2006, PacifiCorp increased its reserve by $9.7 million to reflect its most likely estimate for probable liabilities. Remediation costs that are fixed and determinable have been discounted to their present value using credit-adjusted, risk-free discount rates based on the expected future annual borrowing rates of PacifiCorp. The liability recorded was $38.5 million at March 31, 2006 and $33.3 million at March 31, 2005 and is included as part of Deferred credits — other. The March 31, 2006 recorded liability included $18.1 million of discounted liabilities. Had none of the liabilities included in the $38.5 million balance recorded at March 31, 2006 been discounted, the total would have been $40.7 million. The expected payments for each of the five 12 month periods ending March 31 and thereafter are as follows: $5.4 million in 2007, $3.9 million in 2008, $2.4 million in 2009, $1.5 million in 2010, $1.2 million in 2011 and $26.3 million thereafter.

It is possible that future findings or changes in estimates could require that additional amounts be accrued. Should current circumstances change, it is possible that PacifiCorp could incur an additional undiscounted obligation of up to approximately $53.1 million relating to existing sites. However, management believes that completion or resolution of these matters will have no material adverse effect on PacifiCorp's consolidated financial position or results of operations.

Note 7 — Notes Payable and Commercial Paper

Amounts outstanding under PacifiCorp's short-term notes payable and commercial paper arrangements were as follows:

(Millions of dollars)	Balance	Average Interest Rate
March 31, 2006	$184.4	4.8%
March 31, 2005	468.8	2.9

Revolving Credit Agreement

PacifiCorp amended and restated its existing $800.0 million committed bank revolving credit agreement in August 2005. Changes included an increase to 65.0% in the covenant not to exceed a specified debt-to-capitalization percentage, extension of the termination date to August 29, 2010 and

exclusion of the acquisition of PacifiCorp by MEHC as an event of default under the agreement. As of March 31, 2006, PacifiCorp's revolving credit agreement was fully available and had no borrowings outstanding. The interest on advances under this facility is generally based on the London Interbank Offered Rate (LIBOR) plus a margin that varies based on PacifiCorp's credit ratings. This facility supports PacifiCorp's commercial paper program and $38.1 million of variable rate pollution control revenue bonds.

PacifiCorp's revolving credit agreement contains customary covenants and default provisions and PacifiCorp monitors these covenants on a regular basis. As of March 31, 2006, PacifiCorp was in compliance with the covenants of its revolving credit agreement.

Note 8 — Long-Term Debt and Capital Lease Obligations

PacifiCorp's long-term debt and capital lease obligations were as follows:

	March 31,			
	2006		2005	
(Millions of dollars)	Amount	Average Interest Rate	Amount	Average Interest Rate
First mortgage bonds				
4.3% to 8.8%, due through 2011	$ 901.7	6.0%	$1,171.4	6.2%
5.0% to 9.2%, due 2012 to 2016	1,040.4	6.5	1,040.4	6.5
8.5% to 8.6%, due 2017 to 2021	5.0	8.5	5.0	8.5
6.7% to 8.5%, due 2022 to 2026	424.0	7.4	424.0	7.4
5.3 % to 7.7%, due 2032 to 2036	800.0	6.3	500.0	7.0
Unamortized discount	(4.7)		(4.3)	

Guaranty of pollution-control revenue bonds				
Variable rates, due 2014(a)(b)	40.7	3.1	40.7	2.3
Variable rates, due 2014 to 2026(b)	325.2	3.2	325.2	2.3
Variable rates, due 2025(a)(b)	175.8	3.2	175.8	2.3
3.4% to 5.7%, due 2014 to 2026(a)	184.0	4.5	184.0	4.5
6.2% , due 2031	12.7	6.2	12.7	6.2
Unamortized discount	(0.5)		(0.5)	
Funds held by trustees	(2.2)		(2.1)	
Capital lease obligations				
10.4% to 14.8%, due through 2035	35.8	11.7	26.6	11.9
Total	3,937.9		3,898.9	
Less current maturities	(216.9)		(269.9)	
Total	$3,721.0		$3,629.0	

(a) Secured by pledged first mortgage bonds generally at the same interest rates, maturity dates and redemption provisions as the pollution-control revenue bonds.

(b) Interest rates fluctuate based on various rates, primarily on certificate of deposit rates, interbank borrowing rates, prime rates or other short-term market rates.

First mortgage bonds of PacifiCorp may be issued in amounts limited by PacifiCorp's property, earnings and other provisions of the mortgage indenture. Approximately $13.8 billion of the eligible assets (based on original cost) of PacifiCorp are subject to the lien of the mortgage.

Approximately $2.3 billion of first mortgage bonds were redeemable at PacifiCorp's option at March 31, 2006 at redemption prices dependent upon United States Treasury yields. Approximately $541.7 million of variable-rate pollution-control revenue bonds were redeemable at PacifiCorp's option at par at March 31, 2006. Approximately $71.2 million of fixed-rate pollution-control revenue bonds were redeemable at PacifiCorp's option at par at March 31, 2006. The remaining long-term debt was not redeemable at March 31, 2006.

In September 2005, the SEC declared effective PacifiCorp's shelf registration statement covering $700.0 million of future first mortgage bond and unsecured debt issuances. PacifiCorp has not yet issued any of the securities covered by this registration statement.

In June 2005, PacifiCorp issued $300.0 million of its 5.25% Series of First Mortgage Bonds due June 15, 2035. PacifiCorp used the proceeds for the reduction of short-term debt, including the short-term debt used in December 2004 to redeem its 8.625% Series of First Mortgage Bonds due December 13, 2024 totaling $20.0 million.

In March 2005, the maturity dates were extended to December 1, 2020 for three series of variable-rate pollution-control revenue bonds totaling $38.1 million.

PacifiCorp leases equipment and real estate in various states in which it does business under long-term agreements, extending through March 2035, which are classified as capital leases. These capital leases are payable in monthly installments allocated between principal and imputed interest rates ranging from 10.4% to 14.8%.

In April 2005, PacifiCorp entered into a 30-year transportation service agreement with Questar Pipeline Company for the right to use a newly constructed pipeline facility with a majority of the output designated to provide natural gas to the Currant Creek Power Plant. This agreement qualifies as a capital lease with an initial net present value lease obligation of $12.4 million at an imputed interest rate of 11.3%.

The annual maturities of long-term debt and capital lease obligations for the 12 months ending March 31 are:

(Millions of dollars)	Long-term Debt	Capital Lease Obligations	Total
2007	$ 216.3	$ 4.8	$ 221.1
2008	119.9	4.8	124.7
2009	412.4	4.8	417.2
2010	138.5	5.0	143.5
2011	14.6	4.9	19.5
Thereafter	3,007.8	63.8	3,071.6
	3,909.5	88.1	3,997.6
Unamortized discount	(5.2)	—	(5.2)
Funds held by trustee	(2.2)	—	(2.2)
Amounts representing interest	—	(52.3)	(52.3)
	$3,902.1	$ 35.8	$3,937.9

PacifiCorp made interest payments, net of capitalized interest, of $240.3 million for the year ended March 31, 2006; $220.4 million for the year ended March 31, 2005; and $236.7 million for the year ended March 31, 2004.

At March 31, 2006, PacifiCorp had $517.8 million of standby letters of credit and standby bond purchase agreements available to provide credit enhancement and liquidity support for variable-rate pollution-control revenue bond obligations. In addition, PacifiCorp had approximately $40.5 million of standby letters of credit to provide credit support for certain transactions as requested by third parties. These committed bank arrangements were all fully available as of March 31, 2006 and expire periodically through the 12 months ending March 31, 2011.

PacifiCorp's standby letters of credit and standby bond purchase agreements generally contain similar covenants to those contained in PacifiCorp's revolving credit agreement, although the maximum permitted debt-to-capitalization ratio for one of the standby bond purchase agreements was 60.0% as of March 31, 2006 and was amended in May 2006 to now permit a maximum ratio of 65.0%. See Note 7 — Notes Payable and Commercial Paper for further information. PacifiCorp monitors these covenants on a regular basis in order to ensure that events of default will not occur and as of March 31, 2006, PacifiCorp was in compliance with the covenants of these agreements.

Note 9 — Preferred Stock Subject to Mandatory Redemption

PacifiCorp's Preferred stock subject to mandatory redemption was as follows:

(Thousands of shares, millions of dollars)	**March 31, 2006**		**March 31, 2005**	
Series	**Shares**	**Amount**	**Shares**	**Amount**
Preferred stock subject to mandatory redemption				
$7.48 No Par Serial Preferred, $100 stated value, 16,000 shares authorized	450	$45.0	525	$52.5

PacifiCorp has mandatory redemption requirements on 37,500 shares of the $7.48 series Preferred stock on June 15, 2006, with a non-cumulative option to redeem an additional 37,500 shares on June 15, 2006, at $100.0 per share, plus accrued and unpaid dividends to the date of such redemption. All outstanding shares on June 15, 2007 are subject to mandatory redemption. Holders of Preferred stock subject to mandatory redemption are entitled to certain voting rights and may 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. PacifiCorp redeemed $7.5 million of Preferred stock subject to mandatory and optional redemption during each of the years ended March 31, 2006, 2005 and 2004.

PacifiCorp had $0.8 million at March 31, 2006 and $1.0 million at March 31, 2005 in dividends declared but unpaid on Preferred stock subject to mandatory redemption that were included in Interest payable.

Note 10 — Commitments and Contingencies

PacifiCorp follows SFAS No. 5, to determine accounting and disclosure requirements for contingencies. PacifiCorp operates in a highly regulated environment. Governmental bodies such as the FERC, state regulatory commissions, the SEC, the Internal Revenue Service, the Department of Labor, the United States Environmental Protection Agency (the ''EPA'') and others have authority over various aspects of PacifiCorp's business operations and public reporting. Reserves are established when required in management's judgment, and disclosures regarding litigation, assessments and creditworthiness of customers or counterparties, among others, are made when appropriate. The evaluation of these contingencies is performed by various specialists inside and outside of PacifiCorp.

From time to time, PacifiCorp is also a party to various legal claims, actions, complaints and disputes, certain of which involve material amounts. PacifiCorp has recorded $6.7 million in reserves as of March 31, 2006 related to various outstanding legal actions and disputes, excluding those discussed below. This amount represents PacifiCorp's best estimate of probable losses related to these matters. PacifiCorp currently believes that disposition of these matters will not have a material adverse effect on PacifiCorp's consolidated financial position, results of operations or liquidity.

Environmental matters – PacifiCorp is subject to numerous environmental laws, including the federal Clean Air Act and various state air quality laws; the Endangered Species Act, particularly as it relates to certain endangered species of fish; the Comprehensive Environmental Response, Compensation and Liability Act, and similar state laws relating to environmental cleanups; the Resource Conservation and Recovery Act and similar state laws relating to the storage and handling of hazardous materials; and the Clean Water Act, and similar state laws relating to water quality. These laws could potentially impact future operations. Environmental contingencies identified at March 31, 2006 principally consist of air quality matters. Pending or proposed air regulations will require PacifiCorp to reduce its electricity plant emissions of sulfur dioxide, nitrogen oxides and other pollutants below current levels. These reductions will be required to address regional haze programs, mercury emissions regulations and possible re-interpretations and changes to the federal Clean Air Act. In the future, PacifiCorp expects to incur significant costs to comply with various stricter air emissions requirements. These potential costs are expected to consist primarily of capital expenditures. PacifiCorp expects these costs would be included in rates and, as such, would not have a material adverse impact on PacifiCorp's consolidated results of operations. See also Note 6 — Asset Retirement Obligations and Accrued Environmental Costs.

Hydroelectric relicensing – PacifiCorp's hydroelectric portfolio consists of 51 plants with an aggregate plant net capability of 1,159.4 MW. The FERC regulates 93.9% of the installed capacity of this portfolio through 18 individual licenses. Several of PacifiCorp's hydroelectric projects are in some stage of relicensing under the Federal Power Act. Hydroelectric relicensing and the related environmental compliance requirements are subject to uncertainties. PacifiCorp expects that future costs relating to these matters may be significant and will consist primarily of additional relicensing costs, operations and maintenance expense, and capital expenditures. Electricity generation reductions may result from the additional environmental requirements. PacifiCorp had incurred $70.3 million in costs as of March 31, 2006 for ongoing hydroelectric relicensing, which are reflected in Construction work-in-progress on the Consolidated Balance Sheet. PacifiCorp expects that these and future costs will be included in rates and, as such, will not have a material adverse impact on PacifiCorp's consolidated financial position or results of operations.

In October 2005, the new FERC license for the North Umpqua hydroelectric project became final under the terms of the North Umpqua Settlement Agreement. Prior to this date, the license had been effective, but not final, because environmental groups had challenged its legality before the FERC and in federal court. In September 2005, the Ninth Circuit Court of Appeals issued an order upholding the new license. Since the Court's order was not appealed within the allowed time, all legal challenges of the FERC license order have been exhausted and the license is final for purposes of recording liabilities. PacifiCorp is committed, over the 35-year life of the license, to fund approximately $48.4 million for environmental mitigation and enhancement projects. As a result of the license becoming final, PacifiCorp recorded additional liabilities and intangible assets in October 2005 amounting to a present value of $11.2 million. At March 31, 2006, the liability recorded for all North Umpqua obligations amounted to a present value of $21.8 million.

FERC Issues

California Refund Case **–** PacifiCorp is a party to a FERC proceeding that is investigating potential refunds for energy transactions in the California Independent System Operator and the California Power Exchange markets during past periods of high energy prices. PacifiCorp has a reserve of $17.7 million for these potential refunds. PacifiCorp's ultimate exposure to refunds is dependent upon any order issued by the FERC in this proceeding. In addition, beginning in summer 2000, California market conditions resulted in defaults of amounts due to PacifiCorp from certain counterparties resulting from transactions with the California Independent System Operator and California Power Exchange. PacifiCorp has reserved $5.0 million for these receivables.

FERC Market Power Analysis **–** Pursuant to the FERC's orders granting PacifiCorp authority to sell capacity and energy at market-based rates, PacifiCorp and certain of its former affiliates had been required to submit a joint market power analysis every three years. Under the FERC's current policy, applicants must demonstrate that they do not possess market power in order to charge market-based rates for sales of wholesale energy and capacity in the applicants' control areas. An analysis demonstrating an applicant's passage of certain threshold screens for assessing generation market power establishes a rebuttable presumption that the applicant does not possess generation market power, while failure to pass any screen creates a rebuttable presumption that the applicant has generation market power. In February 2005, PacifiCorp submitted a joint triennial market power analysis in compliance with the FERC's requirements. The analysis indicated that PacifiCorp failed to pass one of the generation market power screens in PacifiCorp's eastern control area and in Idaho Power Company's control area. In May 2005, the FERC issued an order instituting a proceeding pursuant to section 206 of the Federal Power Act to determine whether PacifiCorp may continue to charge market-based rates for sales of wholesale energy and capacity. Under the terms of the order, PacifiCorp and its formerly affiliated co-applicants were required to submit additional information and analysis to the FERC within 60 days to rebut the presumption that PacifiCorp has generation market power. In June and July 2005, PacifiCorp filed additional analysis in response to the FERC's May 2005 order. In January 2006, the FERC requested PacifiCorp to amend its previous filings with additional analysis, which was filed in March 2006. If the FERC ultimately finds that PacifiCorp has market power, PacifiCorp will be required to implement measures to mitigate any exercise of market power,

Table of Contents

which may result in decreased revenues and/or increased operating expenses. PacifiCorp believes the outcome of this proceeding will not have a material impact on its consolidated financial position or results of operations.

Note 11 — Guarantees and Other Commitments

Guarantees

PacifiCorp is generally required to obtain state regulatory commission approval prior to guaranteeing debt or obligations of other parties. In November 2002, the FASB issued Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others* (''FIN 45''). FIN 45 requires disclosure of certain direct and indirect guarantees.

The following represent the indemnification obligations of PacifiCorp as of March 31, 2006 and 2005.

PacifiCorp has made certain commitments related to the decommissioning or reclamation of certain jointly owned facilities and mine sites. The decommissioning guarantees require PacifiCorp to pay a proportionate share of the decommissioning costs based upon percentage of ownership. The mine reclamation obligations require PacifiCorp to pay the mining entity a proportionate share of the mine's reclamation costs based on the amount of coal purchased by PacifiCorp. In the event of default by any of the other joint participants, PacifiCorp potentially may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. PacifiCorp has recorded its estimated share of the decommissioning and reclamation obligations as either an asset retirement obligation, regulatory liability or other liability.

In connection with the sale of PacifiCorp's Montana service territory, PacifiCorp entered into a purchase and sale agreement with Flathead Electric Cooperative in October 1998. Under the agreement, PacifiCorp indemnified Flathead Electric Cooperative for losses, if any, occurring after the closing date and arising as a result of certain breaches of warranty or covenants. The indemnification has a cap of $10.1 million until October 2008 and a cap of $5.1 million thereafter (less expended costs to date). Two indemnity claims relating to environmental issues have been tendered, but remediation costs for these claims, if any, are not expected to be material.

From time to time, PacifiCorp executes contracts that include indemnities typical for the underlying transactions, which are related to sales of businesses, property, plant and equipment, and service territories. These indemnities might include any of the following matters: privacy rights; governmental regulations and employment-related issues; commercial contractual relationships; financial reports; tax-related issues; securities laws; and environmental-related issues. Performance under these indemnities generally would be triggered by breach of representations and warranties in the contract. PacifiCorp regularly evaluates the probability of having to incur costs under the indemnities and appropriately accrues for expected losses that are probable and estimable. Some of these indemnities may not limit potential liability; therefore, PacifiCorp is unable to estimate a maximum potential amount of future payments that could result from claims made under these indemnities. PacifiCorp believes that the likelihood that it would be required to perform or otherwise incur any significant losses associated with any of these obligations is remote.

Table of Contents

Unconditional Purchase Obligations

(Millions of dollars)	Payments due during the 12 months ending March 31, 2007	2008	2009	2010	2011	Thereafter	Total
Construction	$ 111.4	$ 33.2	$ —	$ —	$ —	$ —	$ 144.6
Operating leases	15.0	15.3	2.9	2.1	2.1	8.8	46.2
Purchased electricity	756.3	426.7	284.1	290.6	258.0	2,146.7	4,162.4
Transmission	45.7	39.5	37.7	35.3	36.8	503.3	698.3
Fuel	516.8	600.5	522.5	452.7	339.8	1,931.5	4,363.8
Other	52.6	61.0	59.5	53.6	53.4	837.0	1,117.1
Total commitments	$1,497.8	$1,176.2	$906.7	$834.3	$690.1	$5,427.3	$10,532.4

Construction – PacifiCorp has an ongoing construction program to meet increased electricity usage, customer growth and system reliability objectives. At March 31, 2006, PacifiCorp had estimated long-term unconditional purchase obligations for construction of the new Lake Side Power Plant.

Operating leases – PacifiCorp leases offices, certain operating facilities, land and equipment under operating leases that expire at various dates through the 12 months ended March 31, 2093. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. These leases generally require PacifiCorp to pay for insurance, taxes and maintenance applicable to the leased property. Excluded from the operating lease payments above are any power purchase agreements that meet the definition of an operating lease.

Net rent expense was $28.8 million for the year ended March 31, 2006; $26.1 million for the year ended March 31, 2005; and $29.4 million for the year ended March 31, 2004.

Minimum non-cancelable sublease rent payments expected to be received through the 12 months ended March 31, 2013 total $6.8 million.

Purchased electricity – As part of its energy resource portfolio, PacifiCorp acquires a portion of its electricity through long-term purchases and/or exchange agreements. Included in the purchased electricity payments above are any power purchase agreements that meet the definition of an operating lease.

Included in the minimum fixed annual payments for purchased electricity above are commitments to purchase electricity from several hydroelectric projects under long-term arrangements with public utility districts. These purchases are made on a ''cost-of-service'' basis for a stated percentage of project output and for a like percentage of project operating expenses and debt service. These costs are included in Energy costs in the Consolidated Statements of Income. PacifiCorp is required to pay its portion of operating costs and its portion of the debt service, whether or not any electricity is produced.

At March 31, 2006, PacifiCorp's share of long-term arrangements with public utility districts was as follows:

(Millions of dollars)

Generating Facility	Year Contract Expires	Capacity (MW)	Percentage of Output	Annual Costs(a)
Wanapum	2009	194.1	18.7%	$ 6.6
Rocky Reach	2011	67.8	5.3	3.6
Priest Rapids	2045	61.0	6.5	2.0
Wells	2018	58.3	6.9	2.1
Total		381.2		$ 14.3

(a) Includes debt service totaling $7.0 million.

Table of Contents

PacifiCorp's minimum debt service and estimated operating obligations included in purchased electricity above for the 12 months ending March 31 are as follows:

(Millions of dollars)	Minimum Debt Service	Operating Obligations
2007	$ 9.3	$ 8.3
2008	9.3	8.4
2009	9.3	8.6
2010	4.7	4.8
2011	4.7	4.9
Thereafter	55.5	84.3
	$92.8	$ 119.3

PacifiCorp has a 4.0% entitlement to the generation of the Intermountain Power Project, located in central Utah, through a power purchase agreement. PacifiCorp and the City of Los Angeles have agreed that the City of Los Angeles will purchase capacity and energy from PacifiCorp's 4.0% entitlement of the Intermountain Power Project at a price equivalent to 4.0% of the expenses and debt service of the project.

Fuel – PacifiCorp has ''take or pay'' coal and natural gas contracts that require minimum payments.

Other **–** Unconditional purchase obligations, as defined by accounting standards, are those long-term commitments that are non-cancelable or cancelable only under certain conditions. PacifiCorp has such commitments related to legal or contractual asset retirement obligations, environmental obligations, hydroelectric obligations, equipment maintenance and various other service and maintenance agreements.

Resource Management

PacifiCorp, as a public utility and a franchise supplier, has an obligation to manage resources to supply its customers. Rates charged to most customers are tariff rates authorized by regulatory agencies as discussed in Note 2 — Accounting for the Effects of Regulation.

Note 12 — Jointly Owned Facilities

At March 31, 2006, PacifiCorp's share in jointly owned facilities was as follows:

(Millions of dollars)	PacifiCorp Share	Plant in Service	Accumulated Depreciation/ Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1-4 (a)	66.7%	$ 922.2	$ 467.6	$ 18.3
Wyodak	80.0	308.8	165.9	14.8
Hunter No. 1	93.8	307.7	142.5	1.8
Colstrip Nos. 3 and 4 (a)	10.0	239.2	116.2	1.5
Hunter No. 2	60.3	212.2	99.4	8.1
Hermiston (b)	50.0	167.0	38.9	1.6
Craig Station Nos. 1 and 2	19.3	165.3	71.3	0.7
Hayden Station No. 1	24.5	41.1	18.6	1.0
Foote Creek	78.8	36.3	10.4	—
Hayden Station No. 2	12.6	26.4	12.8	0.3
Trojan (c)	2.5	—	—	—
Other transmission and distribution plants	Various	78.6	21.2	—
Unallocated acquisition adjustments (d)		157.2	75.8	—
Total		$2,662.0	$ 1,240.6	$ 48.1

(a) Includes kilovolt lines and substations.

(b) Additionally, PacifiCorp has contracted to purchase the remaining 50.0% of the output of the Hermiston Plant. See Note 13 — Consolidation of Variable-Interest Entities.

(c) The Trojan Plant was closed in 1993 and PacifiCorp is allowed recovery of costs associated with the plant over the remaining life of the original license. Plant, inventory, fuel and decommissioning costs totaling $8.1 million relating to the Trojan Plant were included in regulatory assets at March 31, 2006.

(d) Represents the excess of the costs of the acquired interests in purchased facilities over their original net book values.

Under the joint ownership agreements, each participating utility is responsible for financing its share of construction, operating and leasing costs. PacifiCorp's portion is recorded in its applicable construction work-in-progress, operations, maintenance and tax accounts, which is consistent with wholly owned plants.

Note 13 — Consolidation of Variable-Interest Entities

In December 2003, the FASB issued revised FIN 46, *Consolidation of Variable-Interest Entities, an interpretation of Accounting Research Bulletin No. 51* (''FIN 46R''), which requires existing unconsolidated variable-interest entities (''VIEs'') to be consolidated by their primary beneficiaries if the entities do not effectively disperse risks among parties involved. FIN 46R was adopted as of January 1, 2004 and resulted in disclosures describing identifiable variable interests.

VIE's Required to be Consolidated

PacifiCorp holds an undivided interest in 50.0% of the 474-MW Hermiston Plant (see Note 12 — Jointly Owned Facilities), procures 100.0% of the fuel input into the plant and subsequently receives 100.0% of the generated electricity, 50.0% of which is acquired through a long-term purchase power agreement. As a result, PacifiCorp holds a variable interest in the joint owner of the remaining 50.0% of the plant and is the primary beneficiary. However, upon adoption of FIN 46R, PacifiCorp was unable to obtain the information necessary to consolidate the entity, because the entity did not agree to supply the information due to the lack of a contractual obligation to do so. PacifiCorp continues to

request from the entity the information necessary to perform the consolidation; however, no information has yet been provided by the entity. Electricity purchased from the joint owner was $35.2 million during the year ended March 31, 2006; $34.8 million during the year ended March 31, 2005; and $33.7 million during the year ended March 31, 2004. The entity is operated by the equity owners, and PacifiCorp has no risk of loss in relation to the entity in the event of a disaster.

Significant Variable-Interests in VIE's not Required to be Consolidated

As discussed in Note 4 — Related-Party Transactions, PacifiCorp leases the West Valley facility from a former affiliate under an operating lease that contains purchase options at specified prices. Although the purchase options are variable-interests in West Valley, PacifiCorp is not the primary beneficiary of the entity. PacifiCorp's exposure to loss under the operating lease is negligible.

PacifiCorp is a party to certain operating and coal purchase agreements with Trapper Mining, Inc. that create a variable interest under the provisions of FIN 46R. Trapper Mining, Inc. owns and operates the Trapper Mine near Craig, Colorado, and produces 100.0% of its output for the benefit of the Craig Power Plant. PacifiCorp has a 21.4% equity interest in Trapper Mining, Inc. and also holds a 19.3% undivided interest in the Craig Power Plant as disclosed in Note 12 — Jointly Owned Facilities. Since each equity investor in Trapper Mining, Inc. also holds a similar interest in the Craig Power Plant, and since none of the joint owners have more than a 50.0% interest in the Craig Power Plant or Trapper Mining, Inc., none of the joint owners are required to consolidate Trapper Mining, Inc. Accordingly, PacifiCorp will continue to account for its interest in Trapper Mining, Inc. via the equity method under APB No. 18, *The Equity Method of Accounting for Investments in Common Stock*, as in prior periods.

Note 14 — Preferred Stock

PacifiCorp's Preferred stock was as follows:

(Thousands of shares, millions of dollars, except per share amounts) Series	Redemption Price Per Share	March 31, 2006 Shares	March 31, 2006 Amount	March 31, 2005 Shares	March 31, 2005 Amount
Preferred stock not subject to mandatory redemption Serial Preferred, $100 stated value, 3,500 shares authorized					
4.52%	$103.5	2	$ 0.2	2	$ 0.2
4.56	102.3	85	8.4	85	8.4
4.72	103.5	70	6.9	70	6.9
5.00	100.0	42	4.2	42	4.2
5.40	101.0	66	6.6	66	6.6
6.00	Non-redeemable	6	0.6	6	0.6
7.00	Non-redeemable	18	1.8	18	1.8
5% Preferred, $100 stated value, 127 shares authorized	110.0	126	12.6	126	12.6
		415	$41.3	415	$41.3

Generally, Preferred stock is redeemable at stipulated prices plus accrued dividends, subject to certain restrictions. Upon 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. Any premium paid on redemptions of Preferred stock is capitalized, and recovery is sought through future rates. 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.

PacifiCorp had $0.5 million at both March 31, 2006 and March 31, 2005 in dividends declared but unpaid on Preferred stock. The shares and amounts outstanding for each series of Preferred stock not subject to mandatory redemption were unchanged from March 31, 2004 through March 31, 2006.

Table of Contents

Note 15 — Common Shareholder's Equity

<u>Common Shareholder's Equity</u> – PacifiCorp has one class of common stock with no par value. A total of 750,000,000 shares were authorized and 357,060,915 shares were issued and outstanding at March 31, 2006 and 312,176,089 shares were issued and outstanding at March 31, 2005. During the year ended March 31, 2006, PacifiCorp issued 44,884,826 shares of its common stock to PHI, its former parent company, at a total price of $484.7 million. The proceeds from the sale of the shares were used to repay short-term debt.

On March 20, 2006, immediately prior to the closing of PacifiCorp's sale to MEHC, PacifiCorp paid a dividend on common stock, at that time held by PHI, in the aggregate amount of $16.8 million. The dividend was reduced pursuant to Amendment No. 1 to the Stock Purchase Agreement among MEHC, ScottishPower and PHI executed on the date of the transaction's closing from the $56.6 million aggregate amount originally declared by the PacifiCorp Board of Directors on January 27, 2006.

In the past, to the extent PacifiCorp did not reimburse ScottishPower for stock-based compensation awarded under ScottishPower plans, such amounts increased the value of PacifiCorp's common shareholder's capital.

<u>Common Dividend Restrictions</u> – MEHC is the sole indirect shareholder of PacifiCorp's common stock. The state regulatory orders that authorized the acquisition of PacifiCorp by MEHC contain restrictions on PacifiCorp's ability to pay dividends to the extent that they would reduce PacifiCorp's common stock equity below specified percentages of defined capitalization.

As of March 31, 2006, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings LLC or MEHC without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 48.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. After December 31, 2008, this minimum level of common equity declines annually to 44.0% after December 31, 2011. The terms of this commitment treat 50.0% of PacifiCorp's preferred stock outstanding prior to the acquisition of PacifiCorp by MEHC as common equity. As of March 31, 2006, PacifiCorp's actual common stock equity percentage, as calculated under this measure, exceeded the minimum threshold.

In addition, PacifiCorp is restricted from making any distributions to PPW Holdings LLC or MEHC if PacifiCorp's unsecured debt rating is BBB− or lower by Standard & Poor's Rating Services or Fitch Ratings or Baa3 or lower by Moody's Investor Service, as indicated by two of the three rating services. As of March 31, 2006, PacifiCorp's unsecured debt rating was BBB+ by Standard & Poor's Rating Services and Fitch Ratings and Baa1 by Moody's Investor Service.

PacifiCorp is also subject to maximum debt-to-total capitalization levels under various debt agreements.

Note 16 — Fair Value of Financial Instruments

(Millions of dollars)	March 31, 2006		March 31, 2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt (a)	$3,902.1	$4,091.4	$3,872.3	$4,209.5
Preferred stock subject to mandatory redemption	45.0	46.3	52.5	56.0

(a) Includes long-term debt classified as currently maturing, less capital lease obligations.

The carrying value of cash and cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments.

Table of Contents

The fair value of PacifiCorp's long-term debt, current maturities of long-term debt and redeemable preferred stock has been estimated by discounting projected future cash flows, using the current rate at which similar loans would be made to borrowers with similar credit ratings and for the same maturities.

Note 17 — Employee Benefits

PacifiCorp sponsors defined benefit pension plans that cover the majority of its employees and also provides health care and life insurance benefits through various plans for eligible retirees. The measurement date for plan assets and obligations is December 31 of each year.

As a result of the sale of PacifiCorp to MEHC, plan participants that were employees or retirees of certain ScottishPower affiliates and a former PacifiCorp mining subsidiary ceased to participate in PacifiCorp's plans. This separation resulted in a net $3.5 million reduction in Common shareholder's capital.

Pension Plans

PacifiCorp's pension plans include the PacifiCorp Retirement Plan (the ''Retirement Plan''), the SERP and a joint trust plan to which PacifiCorp contributes on behalf of certain bargaining unit employees of IBEW Local 57. Benefits under the Retirement Plan are based on the employee's years of service and average monthly pay in the 60 consecutive months of highest pay out of the last 120 months, with adjustments to reflect benefits estimated to be received from social security. Pension costs are funded annually by no more than the maximum amount that can be deducted for federal income tax purposes.

Components of the net periodic pension benefit cost (income) are summarized as follows:

	Years Ended March 31,		
(Millions of dollars)	2006	2005	2004
Service cost (a)	$ 32.2	$ 25.9	$ 25.8
Interest cost	74.4	73.8	73.9
Expected return on plan assets (b)	(76.9)	(77.7)	(80.7)
Amortization of unrecognized net transition obligation	8.4	8.4	8.4
Amortization of unrecognized prior service cost	1.2	1.4	1.5
Amortization of unrecognized loss	21.5	8.5	—
Cost of termination benefits	3.0	—	—
Net periodic pension benefit cost	$ 63.8	$ 40.3	$ 28.9

(a) Includes contributions to the PacifiCorp/IBEW Local 57 Retirement Trust Fund of $1.4 million for the year ended March 31, 2006; no contributions for the year ended March 31, 2005; and contributions of $5.6 million for the year ended March 31, 2004.

(b) The market-related value of plan assets, among other factors, is used to determine expected return on plan assets and is calculated by spreading the difference between expected and actual investment returns over a five-year period beginning in the first year in which they occur.

The weighted-average rates assumed in the actuarial calculations used to determine the net periodic benefit costs for the pension and postretirement benefit plans were as follows:

	Years Ended March 31,		
	2006	2005	2004
Discount rate	5.75%	6.25%	6.75%
Expected long-term rate of return on assets	8.75	8.75	8.75
Rate of increase in compensation levels	4.00	4.00	4.00

PacifiCorp determined the long-term rate of return based on historical asset class returns and current market conditions, taking into account the diversification benefits of investing in multiple asset classes.

Table of Contents

The weighted-average rates assumed in the actuarial calculations used to determine benefit obligations for the pension and postretirement benefit plans were as follows:

	March 31, 2006	2005	2004
Discount rate	5.75%	5.75%	6.25%
Rate of increase in compensation levels	4.00	4.00	4.00

The change in the projected benefit obligation, change in plan assets and funded status of the pension plans are as follows:

(Millions of dollars)	March 31, 2006	2005
Change in projected benefit obligation		
Projected benefit obligation — beginning of year	$1,338.1	$1,229.8
Service cost	30.8	25.9
Interest cost	74.4	73.8
Plan amendments	2.9	1.0
Cost of termination benefits	3.0	—
Separation of former participants	(44.3)	—
Actuarial loss	22.9	86.8
Benefits paid	(84.1)	(79.1)
Transfers	(1.5)	(0.1)
Projected benefit obligation — end of year	$1,342.2	$1,338.1
Change in plan assets		
Plan assets at fair value — beginning of year	$ 806.5	$ 733.2
Actual return on plan assets	72.6	87.5
Separation of former participants	(32.0)	—
Company contributions	63.8	65.0
Benefits paid	(84.1)	(79.1)
Transfers	(1.9)	(0.1)
Plan assets at fair value — end of year	$ 824.9	$ 806.5
Reconciliation of accrued pension cost and total amount recognized		
Funded status of the plan	$ (517.3)	$ (531.6)
Unrecognized net loss	435.6	443.6
Unrecognized prior service cost	10.0	9.1
Unrecognized net transition obligation	7.3	15.9
Accrued postretirement benefit before final contribution	(64.4)	(63.0)
Contribution made after measurement date but before March 31	3.7	—
Accrued pension cost	$ (60.7)	$ (63.0)
Accrued benefit liability	$ (342.3)	$ (383.2)
Intangible asset	17.3	25.0
Accumulated other comprehensive income, pre-tax	6.6	14.5
Regulatory assets	257.7	280.7
Accrued pension cost	$ (60.7)	$ (63.0)

The aggregated accumulated benefit obligation was $1,170.9 million and the fair value of assets was $828.6 million, measured as of December 31, 2005, and including contributions prior to March 31, 2006.

Table of Contents

The Retirement Plan and the SERP currently have assets with a fair value that is less than the accumulated benefit obligation under the Retirement Plan and the SERP, primarily due to prior declines in the equity markets and historically low interest rate levels. As a result, PacifiCorp recognized minimum pension liabilities in the fourth quarters of the years ended March 31, 2006 and 2005. The minimum pension liability adjustment impacted Regulatory assets, Intangible assets and Accumulated other comprehensive income. These adjustments are reflected in the table above and did not materially affect the consolidated results of operations. PacifiCorp requested and received accounting orders from the regulatory commissions in Utah, Oregon, Wyoming and Washington to classify most of the minimum pension liability adjustment as a Regulatory asset instead of a charge to Other comprehensive income. This increase to Regulatory assets will be adjusted in future periods as the difference between the fair value of the trust assets and the accumulated benefit obligation changes. PacifiCorp has determined that costs related to SFAS No. 87, *Employers' Accounting for Pensions* (''SFAS No. 87'') for the Retirement Plan are currently recoverable in rates.

Retirement Plan assets are managed and invested in accordance with all applicable requirements, including the Employee Retirement Income Security Act and the Internal Revenue Code. PacifiCorp employs an investment approach that uses a mix of equities and fixed-income investments to maximize the long-term return of plan assets at a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed-income investments as shown in the table below. Equity investments are diversified across United States and non-United States stocks, as well as growth and value companies, and small and large market capitalizations. Fixed-income investments are diversified across United States and non-United States bonds. Other assets, such as private equity investments, are used to enhance long-term returns while improving portfolio diversification. PacifiCorp primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk through quarterly investment portfolio reviews, annual liability measurements and periodic asset/liability studies.

Details of the Retirement Plan assets by investment category based on market values are as follows:

	Target	March 31, 2006	2005
Equity securities	55.0%	58.5%	56.1%
Debt securities	35.0	34.5	33.9
Private equity	10.0	7.0	10.0

Although the SERP had no qualified assets as of March 31, 2006, PacifiCorp has a Rabbi trust that holds corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERP. Because this plan is nonqualified, the assets in the Rabbi trust are not considered plan assets. The cash surrender value of all of the policies included in the Rabbi trust plus the fair market value of other Rabbi trust investments was $36.4 million at March 31, 2006 and $34.7 million at March 31, 2005, net of amounts borrowed against the cash surrender value.

Other Postretirement Benefits

The cost of other postretirement benefits, including health care and life insurance benefits for eligible retirees, is accrued over the active service period of employees. The transition obligation represents the unrecognized prior service cost and is being amortized over a period of 20 years. PacifiCorp funds other postretirement benefits through a combination of funding vehicles. PacifiCorp contributed $29.7 million for the year ended March 31, 2006; $24.9 million for the year ended March 31, 2005; and $25.3 million for the year ended March 31, 2004. The measurement date for plan assets and obligations is December 31 of each year.

For the postretirement benefit plan assets, PacifiCorp employs an investment approach that uses a mix of equities and fixed-income investments to maximize the long-term return of plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status and corporate financial condition. The investment portfolio contains a diversified

blend of equity and fixed-income investments. Equity investments are diversified across United States and non-United States stocks, as well as growth and value companies, and small and large market capitalizations. Fixed-income investments are diversified across United States and non-United States bonds. Other assets, such as private equity investments, are used to enhance long-term returns while improving portfolio diversification. PacifiCorp primarily minimizes the risk of large losses through diversification, but also monitors and manages other aspects of risk through quarterly investment portfolio reviews, annual liability measurements and periodic asset/liability studies.

The assets for other postretirement benefits are composed of three different trust accounts. The 401(h) account is invested in the same manner as the pension account. Each of the two Voluntary Employees' Beneficiaries Association Trusts has its own investment allocation strategies. Details of the Voluntary Employees' Beneficiaries Association Trusts' assets by investment category based on market values are as follows:

		March 31,	
	Target	**2006**	**2005**
Equity securities	65.0%	66.0%	66.4%
Debt securities	35.0	34.0	33.6

Components of the net periodic postretirement benefit cost are summarized as follows:

	Years Ended March 31,		
(Millions of dollars)	**2006**	**2005**	**2004**
Service cost	$ 8.8	$ 8.5	$ 7.4
Interest cost	30.4	31.0	34.3
Expected return on plan assets (a)	(26.3)	(26.4)	(26.6)
Amortization of unrecognized net transition obligation	12.2	12.2	12.2
Amortization of unrecognized loss	2.7	0.6	0.6
Amortization of prior service cost	2.1	0.1	—
Net periodic postretirement benefit cost	$ 29.9	$ 26.0	$ 27.9

(a) The market-related value of plan assets, among other factors, is used to determine expected return on plan assets and is calculated by spreading the difference between expected and actual investment returns over a five-year period beginning in the first year in which they occur.

The change in the accumulated postretirement benefit obligation, change in plan assets and funded status of the postretirement plan is as follows:

	March 31,	
(Millions of dollars)	**2006**	**2005**
Change in accumulated postretirement benefit obligation		
Accumulated postretirement benefit obligation — beginning of year	$ 528.3	$ 555.3
Service cost	8.8	8.5
Interest cost	30.4	31.0
Plan participant contributions	8.3	7.2
Plan amendments	22.8	0.8
Separation of former participants	(8.9)	—
Actuarial loss (gain)	34.3	(34.4)
Benefits paid	(41.6)	(40.1)
Accumulated postretirement benefit obligation — end of year	$ 582.4	$ 528.3
Change in plan assets		
Plan assets at fair value — beginning of year	$ 286.6	$ 261.6

Actual return on plan assets	20.4	28.6
Company contributions	22.5	29.3
Plan participant contributions	8.3	7.2
Separation of former participants	(4.1)	—
Net benefits paid	(41.6)	(40.1)
Plan assets at fair value — end of year	$ 292.1	$ 286.6
Reconciliation of accrued postretirement costs and total amount recognized		
Funded status of the plan	$(290.3)	$(241.7)
Unrecognized net transition obligation	81.1	94.6
Unrecognized prior service cost	22.1	1.4
Unrecognized loss	138.1	100.1
Accrued postretirement benefit cost, before final contribution	(49.0)	(45.6)
Contribution made after measurement date but before March 31	29.7	24.9
Accrued postretirement cost	$ (19.3)	$ (20.7)

The assumed health care cost trend rates are as follows:

	March 31,		
	2006	**2005**	**2004**
Initial health care cost trend — under 65	10.0%	7.5%	8.5%
Initial health care cost trend — over 65	10.0	9.5	10.5
Ultimate health care cost trend rate	5.0	5.0	5.0
Year that rate reaches ultimate — under 65	2011	2007	2007
Year that rate reaches ultimate — over 65	2011	2009	2009

Table of Contents

The health care cost trend rate assumption has a significant effect on the amounts reported. An annual increase or decrease in the assumed medical care cost trend rate of 1.0% would affect the accumulated postretirement benefit obligation and the service and interest cost components as follows:

Millions of dollars	**One Percent**	
	Increase	**Decrease**
Accumulated postretirement benefit obligation	$ 43.7	$ (35.5)
Service and interest cost components	2.8	(2.4)

Future Contributions and Benefit Payments

In April 2006, PacifiCorp contributed $72.7 million to its Retirement Plan. In addition, PacifiCorp expects to contribute another $11.0 million to its pension plans, as well as $36.6 million to its postretirement benefit plan, during the 12 months ending March 31, 2007. The benefit payments expected to be paid, which reflect expected future service and the Medicare Part D subsidy expected to be received, are as follows:

(Millions of dollars) 12 months ending March 31,	**Retirement Plans**	**Other Postretirement Benefits**	**Medicare Part D Subsidy Receipts**
2007	$ 92.5	$ 35.8	$ (3.0)
2008	92.4	37.9	(3.4)
2009	93.6	40.0	(3.9)
2010	94.7	42.1	(4.3)
2011	97.7	44.4	(4.6)
2012 to 2016 (inclusive)	541.2	248.2	(29.9)

Employee Savings Plan

PacifiCorp has an employee savings plan (the ‘‘Savings Plan’’) that qualifies as a tax-deferred arrangement under the Internal Revenue Code. Eligible employees of adopting affiliates are those who are not temporary, casual, leased or covered by a collective bargaining agreement that does not provide for participation. Employees of any company within the PacifiCorp controlled group of companies that has not adopted the Savings Plan are not eligible. Participating United States employees may defer up to 50.0% of their compensation, subject to certain statutory limitations. Compensation includes base pay, overtime and annual incentive, but is limited to the maximum allowable under the Internal Revenue Code. Employees can select a variety of investment options. PacifiCorp matches 50.0% of employee contributions on amounts deferred up to 6.0% of total compensation, with that portion vesting over the initial five years of an employee’s qualifying service. Thereafter, PacifiCorp’s contributions vest immediately. PacifiCorp’s matching contribution is allocated based on the employee’s investment selections. PacifiCorp may also make an additional contribution equal to a percentage of the employee’s eligible earnings. This additional contribution is allocated based on the employee’s investment selections or to the money market fund if the employee has made no selections. These contributions are immediately vested. PacifiCorp’s contributions to the Savings Plan were $22.5 million for the year ended March 31, 2006; $20.2 million for the year ended March 31, 2005; and $19.3 million for the year ended March 31, 2004; and represent amounts expensed for such periods.

Severance

As a result of general workforce reductions and ScottishPower’s corporate restructuring during the year ended March 31, 2006, PacifiCorp incurred severance expense of $4.1 million under its severance and other benefit plans related to the involuntary termination of approximately 62 employees. Services provided by these employees are expected to be complete by March 31, 2007.

As a result of the MEHC acquisition, PacifiCorp has experienced organizational changes and additional workforce reductions resulting in severance expense of $12.9 million during the year ended March 31, 2006 under its severance and other benefit plans, primarily related to the involuntary termination of 29 employees. Additional severance expense is expected to be incurred in the future as additional organizational changes occur.

Note 18 — Stock-Based Compensation

PacifiCorp Stock Incentive Plan (''PSIP'') – During 1997, PacifiCorp adopted the PSIP. The exercise price of options granted under the PSIP was equal to the market value of the common stock on the date of the grant. ScottishPower took control of the plan upon completion of its merger and all stock options were converted into options to purchase ScottishPower American Depository Shares. The PSIP expired on November 29, 2001 and all outstanding options under the plan were fully vested as of March 31, 2005.

As a result of the sale of PacifiCorp to MEHC and in accordance with the PSIP provisions regarding a change in control, all outstanding options must be exercised no later than 12 months after the date of the sale of PacifiCorp; otherwise they will be forfeited.

ScottishPower Executive Share Option Plan (''ExSOP'') – In prior years, a select group of PacifiCorp employees received grants of stock options under the ScottishPower ExSOP. Certain grants awarded in May 2001 were performance-based awards which resulted in $2.0 million of compensation expense included in Operations and maintenance expense for the year ended March 31, 2005.

As a result of the sale of PacifiCorp to MEHC on March 21, 2006, all ExSOP options held by PacifiCorp employees became fully vested in accordance with the change-in-control provisions of the ExSOP. The change-in-control provisions also provide that all outstanding options are exercisable up to the later of 12 months after the date of the sale of PacifiCorp or 42 months after the date of original option grant. Options that are not exercised within this time period will be forfeited. As of the date of the sale, PacifiCorp ceased to participate in the plan but as of March 31, 2006, there are still options outstanding and exercisable by PacifiCorp employees.

The table below summarizes the stock option activity under the PSIP and the ExSOP.

ScottishPower American Depository Shares	PSIP Number of Shares	PSIP Weighted Average Price	ExSOP Number of Shares	ExSOP Weighted Average Price
Outstanding options at March 31, 2003	3,403,251	$ 31.67	935,054	$ 23.55
Granted	—	—	780,901	24.40
Exercised	(147,496)	25.55	(25,508)	23.55
Forfeited	(331,706)	34.65	(41,991)	23.93
Outstanding options at March 31, 2004	2,924,049	31.64	1,648,456	23.94
Granted	—	—	763,843	28.72
Exercised	(750,126)	26.10	(483,667)	23.84
Forfeited	(40,310)	35.36	(30,136)	26.37
Outstanding options at March 31, 2005	2,133,613	33.52	1,898,496	25.85
Exercised	(1,325,284)	31.32	(1,404,637)	25.58
Forfeited	(30,578)	35.86	(16,096)	27.59
Transfers due to separation	(68,710)	37.35	(164,677)	25.56
Outstanding options at March 31, 2006	709,041	37.15	313,086	27.15

Information with respect to options outstanding and options exercisable under the PSIP and the ExSOP as of March 31, 2006 and 2005 were as follows:

Range of Exercise Prices	Options Outstanding Number of Shares	Options Outstanding Weighted Average Exercise Price	Options Outstanding Weighted Average Remaining Life (in years)	Options Exercisable Number of Shares	Options Exercisable Weighted Average Exercise Price
Year ended March 31, 2006					
PSIP					
$25.70 – $36.64	268,205	$ 31.25	1.0	268,205	$ 31.25
$39.99 – $41.38	440,836	40.74	1.0	440,836	40.74
Total	709,041	37.15	1.0	709,041	37.15
ExSOP					
$23.55 – $28.72	313,086	$ 27.15	1.4	313,086	$ 27.15
Year ended March 31, 2005					
PSIP					
$25.70 – $36.64	1,589,323	$ 31.05	4.2	1,589,323	$ 31.05
$39.99 – $43.83	544,290	40.72	3.0	544,290	40.72
Total	2,133,613	33.52	3.9	2,133,613	33.52
ExSOP					
$23.55 – $28.72	1,898,496	$ 25.85	8.2	182,134	$ 23.97

ScottishPower Long-Term Incentive Plan — In prior years, a select group of PacifiCorp employees received grants of performance share awards under ScottishPower's Long-Term Incentive Plan. The number of shares that actually vest is dependent upon the outcome of certain performance measures over a three-year period. The plan's change-in-control provisions resulted in removal of the employees' future service requirement as of the date of the acquisition but retained the three-year performance requirements. As a result, the number of shares that ultimately vest at the end of the performance period, if any, will be prorated to reflect only the portion of the three-year period which had elapsed between the date of original grant and the date of the sale of PacifiCorp to MEHC. During the year ended March 31, 2006, no stock-based compensation expense was recorded because the performance measures were not yet reached.

Deferred Share Program — In May 2004, ScottishPower implemented a deferred share program under which certain PacifiCorp employees were granted an annual stock bonus award based on a fixed dollar amount but distributable in ScottishPower American Depository Shares with the number of shares to be determined by the quoted market price of the shares at the date of issuance. Historically, compensation expense was accrued throughout the year in which the employee services were rendered and awards earned. During the year ended March 31, 2005, $3.1 million of compensation costs were accrued. However, as a result of the sale of PacifiCorp to MEHC, the program was modified during the year ended March 31, 2006 to provide for a cash payment rather than a share-based payment. The plan was discontinued as of April 1, 2006.

Table of Contents

Note 19 — Income Taxes

The difference between the United States federal statutory tax rate and the effective income tax rate attributed to income from continuing operations is as follows:

	Years Ended March 31,		
	2006	**2005**	**2004**
Federal statutory rate	35.0%	35.0%	35.0%
State taxes, net of federal benefit	2.9	3.8	3.6
Effect of regulatory treatment of depreciation differences	2.5	4.1	4.5
Tax reserves	1.1	(0.9)	(3.1)
Tax credits	(2.6)	(2.3)	(2.5)
Other	(3.3)	0.4	(0.8)
Effective income tax rate	35.6%	40.1%	36.7%

The provision for income taxes is summarized as follows:

	Years Ended March 31,		
(Millions of dollars)	**2006**	**2005**	**2004**
Current			
Federal	$167.3	$ 58.6	$ 63.0
State	18.2	(10.1)	1.0
Total	185.5	48.5	64.0
Deferred			
Federal	19.7	112.6	77.8
State	2.1	15.3	10.6
Total	21.8	127.9	88.4
Investment tax credits	(7.9)	(7.9)	(7.9)
Total income tax expense	$199.4	$168.5	$144.5

The tax effect of temporary differences giving rise to significant portions of PacifiCorp’s deferred tax liabilities and deferred tax assets were as follows:

	March 31,	
(Millions of dollars)	**2006**	**2005**
Deferred tax liabilities:		
Property, plant and equipment	$1,531.2	$1,512.3
Regulatory assets	623.0	667.9
Derivative contract regulatory assets	35.9	64.5
Other deferred tax liabilities	114.3	126.3
	2,304.4	2,371.0
Deferred tax assets:		
Regulatory liabilities	(316.9)	(325.2)
Employee benefits	(170.9)	(185.4)
Derivative contracts	(44.0)	(102.6)
Other deferred tax assets	(134.5)	(126.8)
	(666.3)	(740.0)
Net deferred tax liability	$1,638.1	$1,631.0

PacifiCorp made net income tax payments of $140.0 million for the year ended March 31, 2006; $92.0 million for the year ended March 31, 2005; and $114.1 million for the year ended March 31, 2004. The income tax payments include payments for current federal and state income taxes, as well as amounts paid in settlement of prior years’ liabilities as a result of income tax proceedings.

Table of Contents

PacifiCorp has established, and periodically reviews, an estimated contingent tax reserve on its Consolidated Balance Sheets to provide for the possibility of adverse outcomes in tax proceedings. The net federal and state contingency reserve increased $6.1 million during the year ended March 31, 2006 primarily due to new issues identified for tax years ended after March 31, 2000. The Internal Revenue Service started its examination of the 2001, 2002 and 2003 tax years in October 2004. PacifiCorp anticipates that final settlement and payment on settled issues and other unresolved issues will not have a material adverse impact on its consolidated financial position or results of operations.

The sale of PacifiCorp to MEHC on March 21, 2006 triggered the recognition of a deferred intercompany gain or loss for tax purposes. The recognition of the tax effects of this item is considered to have been recognized immediately prior to the closing of the sale of PacifiCorp while it was part of the PHI consolidated group. PacifiCorp is currently unable to estimate the amount of the tax effect, if any, or determine a range of the potential tax effect. Due to the uncertainty of the amount of the deferred intercompany gain or loss, no adjustments have been recorded as of March 31, 2006.

Pursuant to a formal agreement with PHI and ScottishPower, any tax liabilities generated as a result of a deferred intercompany gain would be recorded as an equity contribution to PacifiCorp. Additionally, as this transaction is deemed to be with shareholders, the net tax expense would be recorded as a reduction in Common shareholder's capital similar to a return of capital distribution. As a result, there would be no net impact to PacifiCorp's Common shareholder's capital, statement of financial position or results of operations.

If a deferred intercompany loss is determined to exist, PacifiCorp would be required to recognize the tax benefit of the deferred intercompany loss as an increase in Common shareholder's capital and establish a corresponding tax receivable or deferred tax asset, depending on whether PacifiCorp would be able to currently utilize the capital loss. In the event a deferred tax asset is created with respect to the capital loss, it will be necessary to determine whether a valuation allowance should be established against the deferred tax asset.

At March 31, 2006, PacifiCorp had no federal or state net operating loss carryforwards. At March 31, 2005, PacifiCorp had total available federal net operating loss carryforwards of approximately $2.7 million and no state net operating loss carryforwards. PacifiCorp has Oregon business energy tax credits of approximately $0.6 million at March 31, 2006 available to reduce future income tax liabilities. These credits begin to expire in 2012. PacifiCorp has Idaho investment tax credits of approximately $1.9 million at March 31, 2006 that are available to reduce future income tax liabilities. These credits begin to expire in 2017. PacifiCorp anticipates utilizing the tax credits prior to the expiration dates.

Note 20 — Concentration of Customers

During the year ended March 31, 2006, no single retail customer accounted for more than 2.0% of PacifiCorp's retail electric revenues, and the 20 largest retail customers accounted for 13.0% of total retail electric revenues. The geographical distribution of PacifiCorp's retail operating revenues for the year ended March 31, 2006 was: Utah, 40.9%; Oregon, 29.3%; Wyoming, 13.3%; Washington, 8.4%; Idaho, 5.7%; and California, 2.4%.

Note 21 — Subsequent Events

On May 10, 2006, the PacifiCorp Board of Directors determined to change PacifiCorp's fiscal year-end from March 31 to December 31. PacifiCorp's report covering the transition period beginning April 1, 2006 and ending December 31, 2006 will be filed on Form 10-K.

SUPPLEMENTAL INFORMATION

QUARTERLY FINANCIAL DATA (UNAUDITED)

	Quarters Ended			
(Millions of dollars, except per share amounts)	**June 30**	**September 30**	**December 31**	**March 31**
2006				
Revenues	$881.4	$620.7	$1,165.0	$1,229.6
Income from operations	135.9	129.2	256.2	270.7
Net income	46.4	39.4	127.8	147.1
Earnings on common stock	45.9	38.9	127.2	146.6
Common dividends declared per share	16.3¢	16.3¢	16.3¢	4.8¢
Common dividends paid per share	16.3¢	16.3¢	16.3¢	4.8¢
2005				
Revenues	$747.8	$828.7	$ 849.5	$ 622.8
Income from operations	129.9	165.3	155.2	206.0
Net income	50.9	61.9	51.3	87.6
Earnings on common stock	50.4	61.4	50.7	87.1
Common dividends declared per share	15.5¢	15.5¢	15.5¢	15.5¢
Common dividends paid per share	15.5¢	15.5¢	15.5¢	15.5¢

On March 31, 2006, MEHC was the only common shareholder of record.

UNAUDITED PRO FORMA FINANCIAL INFORMATION

Index to Unaudited Pro Forma Financial Information

Table of Contents

MIDAMERICAN ENERGY HOLDINGS COMPANY
UNAUDITED PRO FORMA CONDENSED COMBINED
CONSOLIDATED STATEMENTS OF OPERATIONS

The following unaudited pro forma condensed combined consolidated statements of operations are based on the historical consolidated statements of operations of MidAmerican Energy Holdings Company (''MEHC'') and PacifiCorp after giving effect to (i) the $5.1 billion acquisition of PacifiCorp by MEHC using the purchase method of accounting in accordance with Statement of Financial Accounting Standard No. 141, *Business Combinations*, and (ii) the issuance of $1.7 billion of 6.125% senior unsecured bonds due in 2036 (the ''Pro Forma Transactions'').

Under the purchase method of accounting, MEHC's cost to acquire PacifiCorp was preliminarily allocated to the net tangible and identifiable intangible assets acquired and liabilities assumed based upon their estimated fair values as of March 21, 2006, the closing date of the acquisition. The excess of purchase price, including outside fees and costs incurred in connection with the acquisition over the preliminary estimated fair values of the net assets acquired and liabilities assumed was classified as goodwill. PacifiCorp's operations are regulated and are accounted for pursuant to SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation* (''SFAS 71''). Under the rate setting and recovery provisions currently in place for these regulated operations, which provide revenue derived from cost, significant differences between the fair values of the individual tangible and intangible assets and liabilities and their carrying values were recorded with an offset to regulatory assets and liabilities. The following table summarizes the preliminary estimated fair value of assets acquired and liabilities assumed as of the acquisition date (in millions):

	Preliminary Fair Value
Current assets, including cash and cash equivalents of $182.5	$ 1,115.3
Properties, plants and equipment, net	10,050.9
Goodwill	1,074.0
Regulatory assets	1,398.2
Other non-current assets	660.9
Current liabilities, including short-term debt of $184.4 and current portion of long-term debt of $220.6	(1,253.9)
Regulatory liabilities	(818.2)
Pension and postretirement obligations	(827.8)
Subsidiary and project debt, less current portion	(3,762.3)
Deferred income taxes	(1,680.9)
Other non-current liabilities	(836.5)
Net assets acquired	$ 5,119.7

Given the size and timing of the acquisition, the fair values set forth above are preliminary and are subject to adjustment as additional information is obtained. When finalized, adjustments to goodwill may result. MEHC management may identify additional assets and liabilities as part of the definitive allocation process, which may adversely impact future earnings of the combined company, but are not expected to impact cash flows. Refer to Note 3 to the unaudited consolidated financial statements included in MEHC's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2006, for additional discussion regarding the allocation of purchase price.

The unaudited pro forma condensed combined consolidated statements of operations for the year ended December 31, 2005 and the six months ended June 30, 2006, give effect to the Pro Forma Transactions as though it occurred on January 1, 2005. The unaudited pro forma condensed combined consolidated statements of operations include estimates of potential adjustments for events that are (a) directly attributable to the Pro Forma Transactions, (b) factually supportable, and (c) expected to have a continuing impact on MEHC's results following the Pro Forma Transactions.

The fiscal year ends of MEHC and PacifiCorp are December 31 and March 31, respectively. The historical financial information of MEHC for the year ended December 31, 2005, and the six months

Table of Contents

ended June 30, 2006, has been derived from its audited and unaudited consolidated financial statements and notes thereto included elsewhere in this prospectus. The historical financial information of PacifiCorp for the year ended December 31, 2005, and the six months ended June 30, 2006, has been derived from the unaudited consolidated financial statements of PacifiCorp for the three months ended June 30, 2006, included elsewhere in this prospectus, the nine months ended December 31, 2005 and 2004, not included in this prospectus, and the audited consolidated financial statements for the years ended March 31, 2006 and 2005, included elsewhere in this prospectus.

These unaudited pro forma condensed combined consolidated statements of operations should be read in conjunction with (i) the accompanying notes to the unaudited pro forma condensed combined consolidated statements of operations, (ii) the separate audited historical financial statements of MEHC and notes thereto for the year ended December 31, 2005, included elsewhere in this prospectus, (iii) the separate unaudited historical financial statements of MEHC and notes thereto for the six months ended June 30, 2006, included elsewhere in this prospectus, (iv) the separate unaudited historical financial statements and related notes thereto of PacifiCorp for the three-month period ended June 30, 2006, included elsewhere in this prospectus, and for the nine-month periods ended December 31, 2005 and 2004, not included in this prospectus, and (v) the separate audited historical financial statements of PacifiCorp and notes thereto for the years ended March 31, 2006 and 2005, included elsewhere in this prospectus.

These unaudited pro forma condensed combined consolidated statements of operations are presented for illustrative purposes only and are not necessarily indicative of what the combined company's operating results actually would have been had the acquisition been completed on the date indicated. In addition, the unaudited pro forma condensed combined consolidated statements of operations do not purport to project the future operating results of the combined company.

Table of Contents

MIDAMERICAN ENERGY HOLDINGS COMPANY
UNAUDITED PRO FORMA CONDENSED COMBINED CONSOLIDATED STATEMENT OF OPERATIONS
FOR THE YEAR ENDED DECEMBER 31, 2005
(in millions)

		PacifiCorp Acquisition Pro Forma						
		PacifiCorp Historical						
	MEHC Historical	Three Months Ended 3/31/05	Nine Months Ended 12/31/05	As Adjusted	Pro Forma Adjustments	Total	Offering Pro Forma Adjustments	MEHC Pro Forma
Operating revenue	$7,115.5	$622.8	$ 2,667.1	$3,289.9	$ (2.5)(b)	$10,402.9	$ —	$10,402.9
Costs and expenses:								
Cost of sales	3,284.9	58.8	997.0	1,055.8	(2.5)(b)	4,338.2	—	4,338.2
Operating expense and other	1,693.7	247.5	813.2	1,060.7	—	2,754.4	—	2,754.4
Depreciation and amortization	608.2	110.2	335.6	445.8	—	1,054.0	—	1,054.0
Total costs and expenses	5,586.8	416.5	2,145.8	2,562.3	(2.5)	8,146.6	—	8,146.6
Operating income	1,528.7	206.3	521.3	727.6	—	2,256.3	—	2,256.3
Other income (expense):								
Interest expense, net of amounts capitalized	(874.3)	(62.5)	(189.1)	(251.6)	(9.9)(c)	(1,136.1)	(103.5)(f)	(1,239.6)
					(0.3)(d)			
Interest and dividend income	58.1	1.5	7.1	8.6	3.1 (e)	69.8	—	69.8
Other income (expense)	52.4	(1.1)	3.4	2.3	9.9 (c)	64.6	—	64.6
Total other income (expense)	(763.8)	(62.1)	(178.6)	(240.7)	2.8	(1,001.7)	(103.5)	(1,105.2)
Income from continuing operations before income tax expense, minority interest and preferred dividends of subsidiaries and equity income	764.9	144.2	342.7	486.9	2.8	1,254.6	(103.5)	1,151.1
Income tax expense	244.7	56.6	129.1	185.7	1.1(g)	431.5	(41.4)(g)	390.1
Minority interest and preferred dividends of subsidiaries	16.0	0.5	1.6	2.1	—	18.1	—	18.1
Income from continuing operations before equity income	504.2	87.1	212.0	299.1	1.7	805.0	(62.1)	742.9
Equity income	53.3	—	—	—	—	53.3	—	53.3
Income from continuing operations	$ 557.5	$ 87.1	$ 212.0	$ 299.1	$ 1.7	$ 858.3	$ (62.1)	$ 796.2

The accompanying notes are an integral part of these unaudited pro forma financial statements.

Table of Contents

MIDAMERICAN ENERGY HOLDINGS COMPANY
UNAUDITED PRO FORMA CONDENSED COMBINED CONSOLIDATED STATEMENT OF OPERATIONS
FOR THE SIX MONTHS ENDED JUNE 30, 2006
(in millions)

				PacifiCorp Acquisition Pro Forma							
	MEHC Historical			PacifiCorp Historical							
	Six-months Ended 6/30/2006	Pro Forma Adjustments(a)	As Adjusted	Fiscal Year Ended 3/31/2006	Nine-months Ended 12/31/2005	Three-months Ended 6/30/2006	As Adjusted	Pro Forma Adjustments	Total	Offering Pro Forma Adjustments	MEHC Pro Forma
Operating revenue	$ 4,672.1	$ (936.4)	$3,735.7	$ 3,896.7	$ (2,667.1)	$ 859.9	$2,089.5	$ (1.3 (b)	$5,823.9	$ —	$5,823.9
Costs and expenses:											
Cost of sales	2,096.9	(340.1)	1,756.8	1,545.1	(997.0)	336.0	884.1	(1.3 (b)	2,639.6	—	2,639.6
Operating expense and other	1,148.8	(313.9)	834.9	1,111.3	(813.2)	285.8	583.9	—	1,418.8	—	1,418.8
Depreciation and amortization	492.0	(129.1)	362.9	448.3	(335.6)	115.7	228.4	—	591.3	—	591.3
Total costs and expenses	3,737.7	(783.1)	2,954.6	3,104.7	(2,145.8)	737.5	1,696.4	(1.3)	4,649.7	—	4,649.7
Operating income	934.4	(153.3)	781.1	792.0	(521.3)	122.4	393.1	—	1,174.2	—	1,174.2
Other income (expense):											
Interest expense, net of amounts capitalized	(514.9)	72.2	(442.7)	(247.5)	189.1	(58.4)	(116.8)	(12.3 (c)	(571.9)	(51.8 (f)	(623.7)
								(0.1 (d)			
Interest and dividend income	33.6	(2.8)	30.8	9.5	(7.1)	1.6	4.0	1.6 (e)	36.4	—	36.4
Other income (expense)	166.0	(7.5)	158.5	6.1	(3.4)	0.4	3.1	12.1 (c)	173.7	—	173.7
Total other income (expense)	(315.3)	61.9	(253.4)	(231.9)	178.6	(56.4)	(109.7)	1.3	(361.8)	(51.8)	(413.6)
Income from continuing operations before income tax expense, minority interest and preferred dividends of subsidiaries and equity income	619.1	(91.4)	527.7	560.1	(342.7)	66.0	283.4	1.3	812.4	(51.8)	760.6

Income tax expense	212.9	(36.2)	176.7	199.4	(129.1)	23.4	93.7	0.6 (g)	271.0	(20.7 (g)	250.3
Minority interest and preferred dividends of subsidiaries	13.9	(0.3)	13.6	2.1	(1.6)	0.5	1.0	(0.2 (c)	14.4	—	14.4
Income from continuing operations before equity income	392.3	(54.9)	337.4	358.6	(212.0)	42.1	188.7	0.9	527.0	(31.1)	495.9
Equity income	9.7	—	9.7	—	—	—	—	—	9.7	—	9.7
Income from continuing operations	$ 402.0	$ (54.9)	$ 347.1	$ 358.6	$ (212.0)	$ 42.1	$ 188.7	$ 0.9	$ 536.7	$ (31.1)	$ 505.6

The accompanying notes are an integral part of these unaudited pro forma financial statements.

MidAmerican Energy Holdings Company
Notes to Unaudited Pro Forma Condensed Combined Consolidated Statements of Operations

1. Basis of Presentation

On March 21, 2006, a wholly-owned subsidiary of MidAmerican Energy Holdings Company (''MEHC'') acquired 100% of the common stock of PacifiCorp, a regulated electric utility providing service to approximately 1.6 million customers in California, Idaho, Oregon, Utah, Washington and Wyoming from a wholly-owned subsidiary of Scottish Power plc (''ScottishPower'') for a cash price of approximately $5.1 billion. The long-term debt and preferred stock of PacifiCorp, which aggregated to approximately $4.2 billion at March 21, 2006, remained outstanding following completion of the PacifiCorp acquisition. MEHC funded the acquisition of PacifiCorp with the proceeds from the sale of $5.074 billion of MEHC common stock to Berkshire Hathaway Inc. (''Berkshire Hathaway'') and $35.5 million of MEHC common stock to other shareholders (collectively, the ''New Equity Investment'').

The total estimated purchase price of the acquisition and the excess of the purchase price over the book values of the assets acquired and liabilities assumed, as of March 21, 2006, is as follows (in millions):

New Equity Investment	$ 5,109.5
Direct transaction costs(1)	10.2
Total estimated purchase price	5,119.7
Less: Book value of PacifiCorp's assets to be acquired and liabilities to be assumed	(3,995.8)
Post-closing receivable(2)	(49.9)
Estimated excess of the purchase price over book value as of March 21, 2006	$ 1,074.0

(1) The direct transaction costs consist principally of investment banker commissions and outside legal and accounting fees and expenses.

(2) Pursuant to the terms of the Stock Purchase Agreement, as amended, ScottishPower is required to pay MEHC $4.0 million per year for 25 years after the closing date of the acquisition. A discounted asset of $49.9 million, assuming a 6.25% discount rate, was recognized in respect of the contractual receivable.

Under the purchase method of accounting, the total estimated purchase price, as shown in the table above, was allocated to PacifiCorp's net tangible and identified intangible assets acquired and liabilities assumed based on their preliminary estimated fair values as of March 21, 2006, the closing date of the acquisition. The excess of the purchase price over the book value of the net assets acquired and liabilities assumed totaling $1.1 billion, is classified as goodwill in MEHC's consolidated balance sheet. In accordance with Statement of Financial Accounting Standard No. 142, *Goodwill and Other Intangible Assets*, goodwill will not be amortized, but instead will be tested for impairment at least annually. In the event that management determines that the value of goodwill has become impaired, the combined company may incur an accounting charge for the amount of the impairment during the fiscal quarter in which the determination is made.

Statement of Financial Accounting Standard No. 141, *Business Combinations* (''SFAS 141'') requires that the total purchase price be allocated to PacifiCorp's net tangible and identified intangible assets acquired and liabilities assumed based on their preliminary estimated fair values as of the acquisition date. PacifiCorp's operations are regulated and are accounted for pursuant to SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation* (''SFAS 71''). Under the rate setting and recovery provisions currently in place for these regulated operations, which provide revenue derived from cost, significant differences between the fair values of the individual tangible and intangible assets and liabilities and their carrying values were recorded with an offset to regulatory assets and liabilities. Given the size and timing of the acquisition, the fair values are preliminary and are subject

to adjustment as additional information is obtained. When finalized, adjustments to goodwill may result. MEHC management may identify additional assets and liabilities as part of the definitive allocation process, which may adversely impact future earnings of the combined company, but are not expected to impact cash flows. Refer to Note 3 of our Notes to the Unaudited Consolidated Financial Statements included in the ''Financial Statements'' section of this prospectus for additional discussion regarding the allocation of purchase price.

MEHC has not identified any material pre-acquisition contingencies where the related asset, liability or impairment is probable and the amount of the asset, liability or impairment can be reasonably estimated. Prior to the end of the purchase price allocation period, if information becomes available that a pre-acquisition related loss had been incurred and the amounts can be reasonably estimated, such items will be included in the purchase price allocation.

Certain transition activities will occur as PacifiCorp is integrated into MEHC. Costs, consisting primarily of employee termination activities, will be incurred associated with such transition activities. MEHC is in the process of finalizing these plans and expects to execute these plans over the next several months. In accordance with Emerging Issues Task Force Issue No. 95-3, *Recognition of Liabilities in Connection with a Purchase Business Combination* (''EITF 95-3''), the finalization of certain integration plans will result in adjustments to the purchase price allocation for the acquired assets and assumed liabilities of PacifiCorp. Severance costs accrued pursuant to EITF 95-3 during the period from acquisition to June 30, 2006 totaled $17.9 million. Accrued severance costs were $16.2 million at June 30, 2006. Transition costs that do not meet the criteria in EITF 95-3 are expensed in the period incurred.

On March 24, 2006, MEHC issued $1.7 billion of 6.125% senior unsecured bonds due in 2036. MEHC used the entire gross proceeds from the sale of the bonds to repurchase $1.7 billion of common stock issued as part of the New Equity Investment from Berkshire Hathaway.

2. Pro Forma Adjustments

The pro forma adjustments reflect the elimination of intercompany transactions and accounts.

The pro forma combined provision for income taxes does not necessarily reflect the amounts that would have resulted had MEHC and PacifiCorp filed consolidated income tax returns during the periods presented.

(a) Represents the pro forma adjustment to eliminate PacifiCorp's earnings recognized by MEHC from March 21, 2006, the closing date of the acquisition, through June 30, 2006.

(b) Represents the elimination of the intercompany transactions and accounts between PacifiCorp and Intermountain Geothermal Company. Intermountain Geothermal Company, a wholly-owned subsidiary of MEHC at the time of the closing of the acquisition, provides steam under contract to PacifiCorp. In March 2006, subsequent to the acquisition of PacifiCorp, MEHC contributed the shares of Intermountain Geothermal Company to PacifiCorp.

(c) Represents the pro forma adjustment to reclassify equity allowance for funds used during construction and minority interest to conform to MEHC's historical presentation.

(d) Represents the pro forma adjustment to record interest expense on incremental short-term borrowings on transaction costs.

(e) Pursuant to the terms of the Stock Purchase Agreement, as amended, ScottishPower is required to pay MEHC $4.0 million per year for 25 years after the closing date of the acquisition. A discounted asset of $49.9 million, assuming a 6.25% discount rate, was recognized in respect of the contractual receivable. This amount represents the pro forma adjustment to record interest income on the post-closing payment receivable.

(f) Represents the pro forma adjustment to record interest expense, assuming a weighted average interest rate of 6.0% on the $1.7 billion of senior unsecured bonds due in 2036, incremental short-term borrowings, and the amortization of debt issue costs and the settlement of the treasury rate lock agreements.

Table of Contents

(g) Represents the pro forma tax effect of the above adjustments determined based on an estimated statutory tax rate of 40%. This estimate could change based on changes in the applicable tax rates and finalization of the combined company's tax position.

Table of Contents

DEALER PROSPECTUS DELIVERY OBLIGATION

Until October 23, 2006, all dealers that effect transactions in these securities, whether or not participating in the offering, may be required to deliver a prospectus. This is in addition to the dealer's obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

MIDAMERICAN
ENERGY HOLDINGS COMPANY

All tendered initial 2006 bonds, executed letters of transmittal, and other related documents should be directed to the exchange agent. Requests for assistance and for additional copies of this prospectus, the letter of transmittal and other related documents should be directed to the exchange agent.

EXCHANGE AGENT:

THE BANK OF NEW YORK TRUST COMPANY, N.A.

By Facsimile:

212-298-1915

Confirm by telephone:

212-815-5098

By Mail, Hand or Courier:

The Bank of New York Trust Company, N.A.
Corporate Trust Department
Reorganization Unit
101 Barclay Street
Floor 7 East
New York, New York 10286
Attn: Mr. Randolph Holder