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

FORM 10-Q

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

For the quarterly period ended September 30, 2014

or

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

For the transition period from ______ to _______

Commission File Number	Exact name of registrant as specified in its charter; State or other jurisdiction of incorporation or organization	IRS Employer Identification No.
001-14881	**BERKSHIRE HATHAWAY ENERGY COMPANY** **(An Iowa Corporation)** **666 Grand Avenue, Suite 500** **Des Moines, Iowa 50309-2580** **515-242-4300**	**94-2213782**

N/A

(Former name, former address and former fiscal year, if changed since last report)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

All of the shares of common equity of Berkshire Hathaway Energy Company are privately held by a limited group of investors. As of October 31, 2014, 77,466,144 shares of common stock were outstanding.

TABLE OF CONTENTS

PART I

PART II

Definition of Abbreviations and Industry Terms

When used in Forward-Looking Statements, Part I - Items 2 through 4, and Part II - Items 1 through 6, the following terms have the definitions indicated.

Berkshire Hathaway Energy Company and Related Entities	
BHE	Berkshire Hathaway Energy Company
Company	Berkshire Hathaway Energy Company and its subsidiaries
PacifiCorp	PacifiCorp and its subsidiaries
MidAmerican Funding	MidAmerican Funding, LLC and its subsidiaries
MidAmerican Energy	MidAmerican Energy Company
NV Energy	NV Energy, Inc. and its subsidiaries
Nevada Power	Nevada Power Company
Sierra Pacific	Sierra Pacific Power Company
Nevada Utilities	Nevada Power Company and Sierra Pacific Power Company
Northern Natural Gas	Northern Natural Gas Company
Kern River	Kern River Gas Transmission Company
Northern Powergrid Holdings	Northern Powergrid Holdings Company
Pipelines	Consists of Northern Natural Gas and Kern River
MidAmerican Renewables	Consists of MidAmerican Renewables, LLC and CalEnergy Philippines
CE Casecnan	CE Casecnan Water and Energy Company, Inc.
HomeServices	HomeServices of America, Inc. and its subsidiaries
ETT	Electric Transmission Texas, LLC
Utilities	PacifiCorp, MidAmerican Energy Company, Nevada Power Company and Sierra Pacific Power Company
Berkshire Hathaway	Berkshire Hathaway Inc. and its subsidiaries
Topaz	Topaz Solar Farms LLC
Topaz Project	550-megawatt solar project in California
Agua Caliente	Agua Caliente Solar, LLC
Agua Caliente Project	290-megawatt solar project in Arizona
Bishop Hill II	Bishop Hill Energy II LLC
Bishop Hill Project	81-megawatt wind-powered generating facility in Illinois
Jumbo Road	Jumbo Road Holdings, LLC
Jumbo Road Project	300-megawatt wind-powered generating facility in Texas
Solar Star Funding	Solar Star Funding, LLC
Solar Star Projects	A combined 579-megawatt solar project in California

Certain Industry Terms	
AFUDC	Allowance for Funds Used During Construction
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IPUC	Idaho Public Utilities Commission
IUB	Iowa Utilities Board
kV	Kilovolt
MW	Megawatts
OPUC	Oregon Public Utility Commission
PUCN	Public Utilities Commission of Nevada
UPSC	Utah Public Service Commission
WPSC	Wyoming Public Service Commission
WUTC	Washington Utilities and Transportation Commission

Forward-Looking Statements

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

- general economic, political and business conditions, as well as changes in, and compliance with, laws and regulations, including reliability and safety standards, affecting the Company's operations or related industries;
- changes in, and compliance with, environmental laws, regulations, decisions and policies that could, among other items, increase operating and capital costs, reduce facility output, accelerate facility retirements or delay facility construction or acquisition;
- the outcome of rate cases and other proceedings conducted by regulatory commissions or other governmental and legal bodies and the Company's ability to recover costs in rates in a timely manner;
- changes in economic, industry, competition or weather conditions, as well as demographic trends, new technologies and various conservation, energy efficiency and distributed generation measures and programs, that could affect customer growth and usage, electricity and natural gas supply or the Company's ability to obtain long-term contracts with customers and suppliers;
- a high degree of variance between actual and forecasted load or generation that could impact the Company's hedging strategy and the cost of balancing its generation resources with its retail load obligations;
- performance and availability of the Company's facilities, including the impacts of outages and repairs, transmission constraints, weather, including wind, solar and hydroelectric conditions, and operating conditions;
- changes in prices, availability and demand for wholesale electricity, coal, natural gas, other fuel sources and fuel transportation that could have a significant impact on generating capacity and energy costs;
- the financial condition and creditworthiness of the Company's significant customers and suppliers;
- changes in business strategy or development plans;
- availability, terms and deployment of capital, including reductions in demand for investment-grade commercial paper, debt securities and other sources of debt financing and volatility in the London Interbank Offered Rate, the base interest rate for BHE's and its subsidiaries' credit facilities;
- changes in BHE's and its subsidiaries' credit ratings;
- risks relating to nuclear generation;
- the impact of certain contracts used to mitigate or manage volume, price and interest rate risk, including increased collateral requirements, and changes in commodity prices, interest rates and other conditions that affect the fair value of certain contracts;
- the impact of inflation on costs and the Company's ability to recover such costs in regulated rates;
- increases in employee healthcare costs, including the implementation of the Affordable Care Act;
- the impact of investment performance and changes in interest rates, legislation, healthcare cost trends, mortality and morbidity on pension and other postretirement benefits expense and funding requirements;
- changes in the residential real estate brokerage and mortgage industries and regulations that could affect brokerage and mortgage transaction levels;
- unanticipated construction delays, changes in costs, receipt of required permits and authorizations, ability to fund capital projects and other factors that could affect future facilities and infrastructure additions;
- the availability and price of natural gas in applicable geographic regions and demand for natural gas supply;
- the impact of new accounting guidance or changes in current accounting estimates and assumptions on the Company's consolidated financial results;

- the Company's ability to successfully integrate future acquired operations into its business;
- the occurrence of any event, change or other circumstances that could give rise to the termination of the Share Purchase Agreement to acquire 100% of AltaLink, L.P. ("AltaLink") or the failure to consummate the transaction, including the failure to receive the required regulatory approvals, the taking of governmental action (including the passage of legislation) to block the transaction or the failure to satisfy other closing conditions;
- the effects of catastrophic and other unforeseen events, which may be caused by factors beyond the Company's control or by a breakdown or failure of the Company's operating assets, including storms, floods, fires, earthquakes, explosions, landslides, mining accidents, litigation, wars, terrorism and embargoes; and
- other business or investment considerations that may be disclosed from time to time in BHE's filings with the United States Securities and Exchange Commission or in other publicly disseminated written documents.

Further details of the potential risks and uncertainties affecting the Company are described in BHE's filings with the United States Securities and Exchange Commission, including Part II, Item 1A and other discussions contained in this Form 10-Q. The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing factors should not be construed as exclusive.

PART I

Item 1. Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Berkshire Hathaway Energy Company
Des Moines, Iowa

We have reviewed the accompanying consolidated balance sheet of Berkshire Hathaway Energy Company and subsidiaries (the "Company") as of September 30, 2014, and the related consolidated statements of operations and comprehensive income for the three-month and nine-month periods ended September 30, 2014 and 2013, and of changes in equity and cash flows for the nine-month periods ended September 30, 2014 and 2013. 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 Berkshire Hathaway Energy Company and subsidiaries as of December 31, 2013, and the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for the year then ended (not presented herein); and in our report dated March 3, 2014, 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, 2013 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
November 7, 2014

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (Unaudited)
(Amounts in millions)

	As of	
	September 30, 2014	**December 31, 2013**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,481	$ 1,175
Trade receivables, net	1,932	1,769
Inventories	826	853
Deferred income taxes	297	211
Other current assets	922	894
Total current assets	5,458	4,902
Property, plant and equipment, net	53,036	50,119
Goodwill	7,706	7,527
Regulatory assets	3,449	3,322
Investments and restricted cash and investments	3,335	3,236
Other assets	1,038	894
Total assets	$ 74,022	$ 70,000

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

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (Unaudited) (continued)
(Amounts in millions)

	As of	
	September 30, 2014	**December 31, 2013**
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 1,649	$ 1,636
Accrued interest	434	431
Accrued property, income and other taxes	527	362
Accrued employee expenses	361	228
Short-term debt	594	232
Current portion of long-term debt	728	1,188
Other current liabilities	1,430	887
Total current liabilities	5,723	4,964
Regulatory liabilities	2,576	2,498
BHE senior debt	6,366	6,366
BHE junior subordinated debentures	2,294	2,594
Subsidiary debt	22,676	21,864
Deferred income taxes	11,050	10,158
Other long-term liabilities	2,565	2,740
Total liabilities	53,250	51,184
Commitments and contingencies (Note 11)		
Equity:		
BHE shareholders' equity:		
Common stock - 115 shares authorized, no par value, 77 shares issued and outstanding	—	—
Additional paid-in capital	6,423	6,390
Retained earnings	14,114	12,418
Accumulated other comprehensive income (loss), net	113	(97)
Total BHE shareholders' equity	20,650	18,711
Noncontrolling interests	122	105
Total equity	20,772	18,816
Total liabilities and equity	$ 74,022	$ 70,000

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

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS (Unaudited)
(Amounts in millions)

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2014	**2013**	**2014**	**2013**
Operating revenue:				
Energy	$ 4,130	$ 2,778	$ 11,507	$ 8,048
Real estate	644	555	1,619	1,340
Total operating revenue	4,774	3,333	13,126	9,388
Operating costs and expenses:				
Energy:				
Cost of sales	1,410	949	4,328	2,753
Operating expense	888	686	2,567	2,037
Depreciation and amortization	519	378	1,488	1,143
Real estate	582	502	1,518	1,223
Total operating costs and expenses	3,399	2,515	9,901	7,156
Operating income	1,375	818	3,225	2,232
Other income (expense):				
Interest expense	(423)	(309)	(1,266)	(893)
Capitalized interest	20	18	71	58
Allowance for equity funds	23	17	75	55
Other, net	18	14	59	54
Total other income (expense)	(362)	(260)	(1,061)	(726)
Income before income tax expense and equity income	1,013	558	2,164	1,506
Income tax expense	266	49	531	272
Equity income	38	28	84	68
Net income	785	537	1,717	1,302
Net income attributable to noncontrolling interests	9	12	21	28
Net income attributable to BHE shareholders	$ 776	$ 525	$ 1,696	$ 1,274

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

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (Unaudited)
(Amounts in millions)

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2014	2013	2014	2013
Net income	$ 785	$ 537	$ 1,717	$ 1,302
Other comprehensive (loss) income, net of tax:				
Unrecognized amounts on retirement benefits, net of tax of $13, $(8), $13 and $11	40	(21)	44	36
Foreign currency translation adjustment	(214)	212	(83)	(1)
Unrealized gains on available-for-sale securities, net of tax of $79, $105, $158 and $136	119	156	236	200
Unrealized (losses) gains on cash flow hedges, net of tax of $(5), $(1), $8 and $4	(6)	(2)	13	5
Total other comprehensive (loss) income, net of tax	(61)	345	210	240
Comprehensive income	724	882	1,927	1,542
Comprehensive income attributable to noncontrolling interests	9	12	21	28
Comprehensive income attributable to BHE shareholders	$ 715	$ 870	$ 1,906	$ 1,514

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

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY (Unaudited)
(Amounts in millions)

	BHE Shareholders' Equity						
	Common		Additional Paid-in	Retained	Accumulated Other Comprehensive	Noncontrolling	Total
	Shares	Stock	Capital	Earnings	(Loss) Income, Net	Interests	Equity
Balance at December 31, 2012	75	$ —	$ 5,423	$ 10,782	$ (463)	$ 168	$ 15,910
Net income	—	—	—	1,274	—	16	1,290
Other comprehensive income	—	—	—	—	240	—	240
Distributions	—	—	—	—	—	(16)	(16)
Redemption of preferred securities of subsidiaries	—	—	—	—	—	(32)	(32)
Other equity transactions	—	—	(33)	—	—	4	(29)
Balance at September 30, 2013	75	$ —	$ 5,390	$ 12,056	$ (223)	$ 140	$ 17,363
Balance at December 31, 2013	77	$ —	$ 6,390	$ 12,418	$ (97)	$ 105	$ 18,816
Net income	—	—	—	1,696	—	13	1,709
Other comprehensive income	—	—	—	—	210	—	210
Distributions	—	—	—	—	—	(16)	(16)
Other equity transactions	—	—	33	—	—	20	53
Balance at September 30, 2014	77	$ —	$ 6,423	$ 14,114	$ 113	$ 122	$ 20,772

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

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)
(Amounts in millions)

	Nine-Month Periods Ended September 30,	
	2014	2013
Cash flows from operating activities:		
Net income	$ 1,717	$ 1,302
Adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization	1,511	1,166
Allowance for equity funds	(75)	(55)
Deferred income taxes and amortization of investment tax credits	1,063	650
Other, net	(20)	(25)
Changes in other operating assets and liabilities, net of effects from acquisitions:		
Trade receivables and other assets	(74)	134
Derivative collateral, net	(30)	49
Pension and other postretirement benefit plans	(23)	(45)
Accrued property, income and other taxes	201	407
Accounts payable and other liabilities	70	100
Net cash flows from operating activities	4,340	3,683
Cash flows from investing activities:		
Capital expenditures	(4,060)	(2,885)
Acquisitions, net of cash acquired	(246)	(210)
Decrease (increase) in restricted cash and investments	184	(464)
Purchases of available-for-sale securities	(131)	(128)
Proceeds from sales of available-for-sale securities	101	114
Equity method investments	(22)	(58)
Other, net	(6)	10
Net cash flows from investing activities	(4,180)	(3,621)
Cash flows from financing activities:		
Repayments of BHE senior debt and junior subordinated debentures	(550)	—
Proceeds from subsidiary debt	1,272	2,496
Repayments of subsidiary debt	(884)	(437)
Net proceeds from (repayments of) short-term debt	367	(919)
Other, net	(57)	(93)
Net cash flows from financing activities	148	1,047
Effect of exchange rate changes	(2)	(3)
Net change in cash and cash equivalents	306	1,106
Cash and cash equivalents at beginning of period	1,175	776
Cash and cash equivalents at end of period	$ 1,481	$ 1,882

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

(1) General

Berkshire Hathaway Energy Company ("BHE") is a holding company that owns subsidiaries principally engaged in energy businesses (collectively with its subsidiaries, the "Company"). BHE is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

The Company's operations are organized and managed as ten distinct platforms: PacifiCorp, MidAmerican Funding, LLC ("MidAmerican Funding") (which primarily consists of MidAmerican Energy Company ("MidAmerican Energy")), NV Energy, Inc. ("NV Energy") (which primarily consists of Nevada Power Company ("Nevada Power") and Sierra Pacific Power Company ("Sierra Pacific")), Northern Natural Gas Company ("Northern Natural Gas"), Kern River Gas Transmission Company ("Kern River"), Northern Powergrid Holdings Company ("Northern Powergrid Holdings") (which primarily consists of Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc), MidAmerican Transmission, LLC (which owns a 50% interest in Electric Transmission Texas, LLC ("ETT") and Electric Transmission America, LLC), MidAmerican Renewables, LLC (which owns interests in independent power projects in the United States), CalEnergy Philippines (which owns a majority interest in the Casecnan project in the Philippines), and HomeServices of America, Inc. (collectively with its subsidiaries, "HomeServices"). Through these platforms, the Company owns four utility companies in the United States serving customers in 11 states, two interstate natural gas pipeline companies in the United States, two electricity distribution companies in Great Britain, a 50% interest in electric transmission businesses, a diversified portfolio of independent power projects, the second largest residential real estate brokerage firm in the United States and the second largest residential real estate brokerage franchise network in the United States. Northern Natural Gas and Kern River have been aggregated in the reportable segment called Pipelines, MidAmerican Renewables, LLC and CalEnergy Philippines have been aggregated in the reportable segment called MidAmerican Renewables and MidAmerican Transmission, LLC has been included in BHE and Other.

The unaudited Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim financial information and the United States Securities and Exchange Commission's rules and regulations for Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the disclosures required by GAAP for annual financial statements. Management believes the unaudited Consolidated Financial Statements contain all adjustments (consisting only of normal recurring adjustments) considered necessary for the fair presentation of the unaudited Consolidated Financial Statements as of September 30, 2014 and for the three- and nine-month periods ended September 30, 2014 and 2013. The results of operations for the three- and nine-month periods ended September 30, 2014 are not necessarily indicative of the results to be expected for the full year.

The preparation of the unaudited Consolidated Financial Statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the unaudited Consolidated Financial Statements and the reported amounts of revenue and expenses during the period. Actual results may differ from the estimates used in preparing the unaudited Consolidated Financial Statements. Note 2 of Notes to Consolidated Financial Statements included in the Company's Annual Report on Form 10-K for the year ended December 31, 2013 describes the most significant accounting policies used in the preparation of the unaudited Consolidated Financial Statements. There have been no significant changes in the Company's assumptions regarding significant accounting estimates and policies during the nine-month period ended September 30, 2014.

(2) New Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014-09, which creates FASB Accounting Standards Codification ("ASC") Topic 606, "Revenue from Contracts with Customers" and supersedes ASC Topic 605, "Revenue Recognition." The guidance replaces industry-specific guidance and establishes a single five-step model to identify and recognize revenue. The core principle of the guidance is that an entity should recognize revenue upon transfer of control of promised goods or services to customers in an amount that reflects the consideration to which an entity expects to be entitled in exchange for those goods or services. Additionally, the guidance requires the entity to disclose further quantitative and qualitative information regarding the nature and amount of revenues arising from contracts with customers, as well as other information about the significant judgments and estimates used in recognizing revenues from contracts with customers. This guidance is effective for interim and annual reporting periods beginning after December 15, 2016. Early application is not permitted. This guidance may be adopted retrospectively or under a modified retrospective method where the cumulative effect is recognized at the date of initial application. The Company is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In February 2013, the FASB issued ASU No. 2013-04, which amends FASB ASC Topic 405, "Liabilities." The amendments in this guidance require an entity to measure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date as the amount the reporting entity agreed to pay plus any additional amounts the reporting entity expects to pay on behalf of its co-obligor. Additionally, the guidance requires the entity to disclose the nature and amount of the obligation, as well as other information about those obligations. The Company adopted this guidance on January 1, 2014. The adoption of this guidance did not have a material impact on the Company's disclosures included within Notes to Consolidated Financial Statements.

(3) Business Acquisitions

NV Energy, Inc.

Description of the Transaction

On December 19, 2013, BHE completed the merger contemplated by the Agreement and Plan of Merger dated May 29, 2013, among BHE, Silver Merger Sub, Inc. ("Merger Sub"), BHE's wholly-owned subsidiary, and NV Energy, whereby Merger Sub was merged into NV Energy and NV Energy became an indirect wholly-owned subsidiary of BHE ("NV Energy Transaction") for a purchase price of $5.6 billion. NV Energy owns two regulated public utilities, Nevada Power and Sierra Pacific (together, the "Nevada Utilities"), that provide electric service to 1.2 million regulated retail electric customers and 0.2 million regulated retail natural gas customers in Nevada.

Allocation of Purchase Price

The operations of the Nevada Utilities are subject to the rate-setting authority of the Public Utilities Commission of Nevada ("PUCN") and the Federal Energy Regulatory Commission ("FERC") and are accounted for pursuant to GAAP, including the authoritative guidance for regulated operations. The rate-setting and cost recovery provisions establish retail rates on a cost-of-service basis designed to allow the Nevada Utilities an opportunity to recover their costs of providing service and a return on their investments in rate base. Except for regulatory assets not earning a return and certain assets not currently in rates, the fair value of the Nevada Utilities' assets acquired and liabilities assumed subject to these rate-setting provisions are assumed to approximate their carrying values and, therefore, no fair value adjustments have been reflected related to these amounts.

The fair value of NV Energy's assets acquired and liabilities assumed not subject to the rate-setting provisions discussed above was determined using an income approach. This approach is based on significant estimates and assumptions, including Level 3 inputs, which are judgmental in nature. The estimates and assumptions include the projected timing and amount of future cash flows, discount rates reflecting the risk inherent in the future cash flows and future market prices. The fair value of certain assets not currently in rates and certain environmental and other contingencies, among other items, are provisional and are subject to revision for up to 12 months following the acquisition date until the related valuations are completed. These items may be adjusted through regulatory assets or liabilities, to the extent recoverable in rates, or goodwill provided additional information is obtained about the facts and circumstances that existed as of the acquisition date. Such information includes, but is not limited to, the resolution of matters pertaining to the recovery of certain assets not currently in rates and the resolution of certain environmental and other contingency related items.

NV Energy's non-regulated assets acquired and liabilities assumed consist principally of NV Energy's long-term debt, which fair value was determined based on quoted market prices.

The following table summarizes the fair values of the assets acquired and liabilities assumed as of the acquisition date (in millions):

	Fair Value
Current assets, including cash and cash equivalents of $304	$ 1,158
Property, plant and equipment	9,518
Goodwill	2,363
Other long-term assets	1,347
Total assets	14,386
Current liabilities, including current portion of long-term debt of $218	880
Subsidiary debt, less current portion	5,116
Deferred income taxes	1,757
Other long-term liabilities	1,037
Total liabilities	8,790
Net assets acquired	$ 5,596

During the nine-month period ended September 30, 2014, the Company made revisions to regulatory assets not earning a return, certain assets not currently in rates and certain environmental and other contingencies based upon the receipt of additional information about the facts and circumstances that existed as of the acquisition date. Provisional amounts are subject to further revision for up to 12 months following the acquisition date until the related valuations are completed.

Goodwill

The excess of the purchase price paid over the estimated fair values of the identifiable assets acquired and liabilities assumed totaled $2.4 billion and is reflected as goodwill in the NV Energy reportable segment. The goodwill reflects the value paid primarily for the long-term opportunity to improve operating results through the efficient management of operating expenses and the deployment of capital, as well as the opportunity to improve regulatory relationships and develop customer solutions to meet the long-term needs of the Nevada Utilities. Goodwill is not amortized, but rather is reviewed annually for impairment or more frequently if indicators of impairment exist. None of the goodwill recognized is deductible for income tax purposes, and no deferred income taxes have been recorded related to the goodwill.

Pro Forma Financial Information

The following unaudited pro forma financial information reflects the consolidated results of operations of BHE assuming the acquisition had taken place on January 1, 2012 (in millions):

	Nine-Month Period Ended September 30, 2013
Operating revenue	$ 11,660
Net income attributable to BHE shareholders	$ 1,506

The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of the consolidated results of operations that would have been achieved or the future consolidated results of operations of BHE. The information is provisional in nature and subject to change based on final purchase accounting adjustments.

AltaLink, L.P.

On May 1, 2014, BHE entered into a Share Purchase Agreement whereby BHE, through a subsidiary, will acquire 100% of AltaLink, L.P. ("AltaLink"), an indirect wholly-owned subsidiary of SNC-Lavalin Group Inc. ("SNC-Lavalin"), for an estimated cash purchase price of C$3.2 billion (approximately US$2.9 billion as of September 30, 2014). The purchase price is subject to adjustments based on certain capital contributions made into AltaLink and an interest component that will change based on the timing of closing. BHE's shareholders have committed to provide the capital to fund the entire purchase price of AltaLink; however, BHE expects to fund the purchase price with capital from Berkshire Hathaway and by issuing senior unsecured debt at BHE. AltaLink is a regulated transmission-only business, headquartered in Calgary, Alberta. The transaction has been approved by both the SNC-Lavalin and BHE boards of directors. In June 2014, an Advance Ruling Certificate was received from the Commissioner of Competition, providing clearance for the AltaLink acquisition. On July 25, 2014, the Canadian Minister of Industry approved the transaction under the Investment Canada Act, determining that the AltaLink transaction constitutes a net benefit to Canada. The Share Purchase Agreement contains customary representations, warranties and covenants of both SNC-Lavalin and BHE, and is subject to customary closing conditions, including one remaining governmental approval by the Alberta Utilities Commission. The transaction is expected to be completed by the end of 2014.

Other

The Company completed various acquisitions totaling $246 million for the nine-month period ended September 30, 2014. The purchase price for each acquisition was allocated to the assets acquired and liabilities assumed, which related primarily to property, plant and equipment of $641 million, goodwill of $93 million, long-term debt of $231 million and noncurrent deferred income tax liabilities of $183 million for the remaining 50% interest in CE Generation, LLC ("CE Generation"), development and construction costs for the 300-megawatt ("MW") TX Jumbo Road Wind, LLC wind-powered generation project ("Jumbo Road Project") and a residential real estate brokerage business. There were no other material assets acquired or liabilities assumed.

(4) Property, Plant and Equipment, Net

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

		As of	
	Depreciable Life	September 30, 2014	December 31, 2013
Regulated assets:			
Utility generation, distribution and transmission system	5-80 years	$ 59,864	$ 57,490
Interstate pipeline assets	3-80 years	6,508	6,448
		66,372	63,938
Accumulated depreciation and amortization		(21,223)	(19,874)
Regulated assets, net		45,149	44,064
Nonregulated assets:			
Independent power plants	5-30 years	3,847	1,994
Other assets	3-30 years	704	522
		4,551	2,516
Accumulated depreciation and amortization		(790)	(678)
Nonregulated assets, net		3,761	1,838
Net operating assets		48,910	45,902
Construction work-in-progress		4,126	4,217
Property, plant and equipment, net		$ 53,036	$ 50,119

Construction work-in-progress includes $2.8 billion as of September 30, 2014 and December 31, 2013 related to the construction of regulated assets.

(5) Investments and Restricted Cash and Investments

Investments and restricted cash and investments consists of the following (in millions):

	As of	
	September 30, 2014	December 31, 2013
Investments:		
BYD Company Limited common stock	$ 1,494	$ 1,103
Rabbi trusts	380	373
Other	144	126
Total investments	2,018	1,602
Equity method investments:		
ETT	498	454
Bridger Coal Company	182	178
Agua Caliente Solar, LLC	61	41
CE Generation(1)	—	185
Other	93	85
Total equity method investments	834	943
Restricted cash and investments:		
Quad Cities Station nuclear decommissioning trust funds	410	394
Solar Star and Topaz Projects	32	236
Other	139	126
Total restricted cash and investments	581	756
Total investments and restricted cash and investments	$ 3,433	$ 3,301
Reflected as:		
Current assets	$ 98	$ 65
Noncurrent assets	3,335	3,236
Total investments and restricted cash and investments	$ 3,433	$ 3,301

(1) In June 2014, the Company acquired the remaining 50% interest in CE Generation. Refer to Note 3 for additional information.

Investments

BHE's investment in BYD Company Limited common stock is accounted for as an available-for-sale security with changes in fair value recognized in accumulated other comprehensive income (loss) ("AOCI"). As of September 30, 2014 and December 31, 2013, the fair value of BHE's investment in BYD Company Limited common stock was $1.5 billion and $1.1 billion, respectively, which resulted in a pre-tax unrealized gain of $1.3 billion and $871 million as of September 30, 2014 and December 31, 2013, respectively.

(6) Recent Financing Transactions

Long-Term Debt

In July 2014, NV Energy redeemed its $195 million variable-rate term loan due October 2014.

In June 2014, BHE repaid at par value $300 million, plus accrued interest, of its junior subordinated debentures due December 2043.

In April 2014, MidAmerican Energy issued $150 million of its 2.40% First Mortgage Bonds due March 2019, $300 million of its 3.50% First Mortgage Bonds due October 2024 and $400 million of its 4.40% First Mortgage Bonds due October 2044. The net proceeds were used for the optional redemption in May 2014 of $350 million of MidAmerican Energy's 4.65% Senior Notes due October 2014 and for general corporate purposes.

In March 2014, PacifiCorp issued $425 million of its 3.60% First Mortgage Bonds due April 2024. The net proceeds were used to fund capital expenditures and for general corporate purposes.

Credit Facilities

In June 2014, BHE entered into a $1.4 billion senior unsecured credit facility expiring in June 2017. This credit facility has a variable interest rate based on the London Interbank Offered Rate ("LIBOR") or a base rate, at BHE's option, plus a spread that varies based on BHE's senior unsecured long-term debt credit ratings. This credit facility is for general corporate purposes and also supports BHE's commercial paper program and provides for the issuance of letters of credit. The credit facility requires that BHE's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.70 to 1.0 as of the last day of each quarter.

In June 2014, Nevada Power amended its $500 million secured credit facility expiring in March 2017, reducing the amount available to $400 million and extending the maturity date to March 2018. The amended facility has a variable interest rate based on LIBOR or a base rate, at Nevada Power's option, plus a spread that varies based on Nevada Power's secured debt credit rating. The amended facility requires that Nevada Power's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.68 to 1.0 as of the last day of each quarter.

In June 2014, Sierra Pacific amended its $250 million secured credit facility expiring in March 2017, extending the maturity date to March 2018. The amended facility has a variable interest rate based on LIBOR or a base rate, at Sierra Pacific's option, plus a spread that varies based on Sierra Pacific's secured debt credit rating. The amended facility requires that Sierra Pacific's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.68 to 1.0 as of the last day of each quarter.

In March 2014, PacifiCorp arranged for the cancellation of $97 million of letters of credit previously issued to support variable-rate tax-exempt bond obligations. As of September 30, 2014, PacifiCorp had $451 million of fully available letters of credit issued under committed arrangements to support variable-rate tax-exempt bond obligations, of which $270 million were issued under revolving credit facilities. As of September 30, 2014, PacifiCorp had $142 million of variable-rate tax-exempt bond obligations outstanding supported by its revolving credit facilities.

(7) Income Taxes

A reconciliation of the federal statutory income tax rate to the effective income tax rate applicable to income before income tax expense is as follows:

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2014	2013	2014	2013
Federal statutory income tax rate	35%	35%	35%	35%
Income tax credits	(10)	(17)	(10)	(13)
State income tax, net of federal income tax benefit	2	1	2	2
Income tax effect of foreign income	(2)	(12)	(3)	(6)
Equity income	1	2	1	2
Other, net	—	—	—	(2)
Effective income tax rate	26%	9%	25%	18%

Income tax credits relate primarily to production tax credits earned by wind-powered generating facilities owned by MidAmerican Energy, PacifiCorp and Bishop Hill Energy II LLC. Federal renewable electricity production tax credits are earned as energy from qualifying wind-powered generating facilities is produced and sold and are based on a per-kilowatt hour rate pursuant to the applicable federal income tax law. Wind-powered generating facilities are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in-service.

In the third quarter of 2013, the Company recognized $54 million of deferred income tax benefits upon the enactment of a reduction in the United Kingdom corporate income tax rate from 23% to 21% effective April 1, 2014, and a further reduction to 20% effective April 1, 2015.

Berkshire Hathaway includes the Company in its United States federal income tax return. For the nine-month periods ended September 30, 2014 and 2013, the Company received net cash payments for income taxes from Berkshire Hathaway totaling $764 million and $825 million, respectively.

(8) Employee Benefit Plans

Domestic Operations

Net periodic benefit cost for the domestic pension and other postretirement benefit plans included the following components (in millions):

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2014	2013	2014	2013
Pension:				
Service cost	$ 11	$ 5	$ 28	$ 17
Interest cost	32	23	98	66
Expected return on plan assets	(41)	(31)	(123)	(90)
Net amortization	8	15	28	44
Net periodic benefit cost	$ 10	$ 12	$ 31	$ 37
Other postretirement:				
Service cost	$ 4	$ 4	$ 11	$ 10
Interest cost	11	8	34	25
Expected return on plan assets	(14)	(10)	(39)	(32)
Net amortization	(1)	1	(3)	4
Net periodic benefit cost	$ —	$ 3	$ 3	$ 7

Employer contributions to the domestic pension and other postretirement benefit plans are expected to be $48 million and $2 million, respectively, during 2014. As of September 30, 2014, $14 million and $1 million of contributions had been made to the domestic pension and other postretirement benefit plans, respectively.

Foreign Operations

Net periodic benefit cost for the United Kingdom pension plan included the following components (in millions):

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2014	2013	2014	2013
Service cost	$ 6	$ 5	$ 18	$ 16
Interest cost	24	21	72	63
Expected return on plan assets	(31)	(25)	(94)	(75)
Net amortization	12	14	39	41
Net periodic benefit cost	$ 11	$ 15	$ 35	$ 45

Employer contributions to the United Kingdom pension plan are expected to be £56 million during 2014. As of September 30, 2014, £42 million, or $70 million, of contributions had been made to the United Kingdom pension plan.

(9) Risk Management and Hedging Activities

The Company is exposed to the impact of market fluctuations in commodity prices, interest rates and foreign currency exchange rates. The Company is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk primarily through BHE's ownership of PacifiCorp, MidAmerican Energy, Nevada Power and Sierra Pacific (the "Utilities") as they have an obligation to serve retail customer load in their regulated service territories. MidAmerican Energy also provides nonregulated retail electricity and natural gas services in competitive markets. The Utilities' load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity, wholesale electricity that is purchased and sold, and natural gas supply for retail customers. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. Interest rate risk exists on variable-rate debt and future debt issuances. Additionally, the Company is exposed to foreign currency exchange rate risk from its business operations and investments in Great Britain. The Company does not engage in a material amount of proprietary trading activities.

Each of the Company's business platforms has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, the Company uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. The Company manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. Additionally, the Company may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate the Company's exposure to interest rate risk. The Company does not hedge all of its commodity price, interest rate and foreign currency exchange rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in the Company's accounting policies related to derivatives. Refer to Note 10 for additional information on derivative contracts.

The following table, which reflects master netting arrangements and excludes contracts that have been designated as normal under the normal purchases or normal sales exception afforded by GAAP, summarizes the fair value of the Company's derivative contracts, on a gross basis, and reconciles those amounts to the amounts presented on a net basis on the Consolidated Balance Sheets (in millions):

	Other Current Assets	Other Assets	Other Current Liabilities	Other Long-term Liabilities	Total
As of September 30, 2014					
Not designated as hedging contracts:					
Commodity assets[1]	$ 16	$ 58	$ 26	$ —	$ 100
Commodity liabilities[1]	(3)	(1)	(111)	(101)	(216)
Interest rate assets	3	—	—	—	3
Interest rate liabilities	—	—	(1)	(1)	(2)
Total	16	57	(86)	(102)	(115)
Designated as hedging contracts:					
Commodity assets	14	—	6	5	25
Commodity liabilities	(5)	—	(1)	(9)	(15)
Interest rate assets	—	4	—	—	4
Interest rate liabilities	—	—	(5)	—	(5)
Total	9	4	—	(4)	9
Total derivatives	25	61	(86)	(106)	(106)
Cash collateral receivable	—	—	41	5	46
Total derivatives - net basis	$ 25	$ 61	$ (45)	$ (101)	$ (60)
As of December 31, 2013					
Not designated as hedging contracts:					
Commodity assets[1]	$ 16	$ 62	$ 18	$ 2	$ 98
Commodity liabilities[1]	(2)	(1)	(78)	(145)	(226)
Interest rate assets	3	5	—	—	8
Interest rate liabilities	—	—	(1)	—	(1)
Total	17	66	(61)	(143)	(121)
Designated as hedging contracts:					
Commodity assets	1	—	1	—	2
Commodity liabilities	(1)	—	(5)	(8)	(14)
Interest rate assets	—	6	—	—	6
Interest rate liabilities	—	—	(6)	—	(6)
Total	—	6	(10)	(8)	(12)
Total derivatives	17	72	(71)	(151)	(133)
Cash collateral receivable	(2)	—	1	13	12
Total derivatives - net basis	$ 15	$ 72	$ (70)	$ (138)	$ (121)

(1) The Company's commodity derivatives not designated as hedging contracts are generally included in regulated rates, and as of September 30, 2014 and December 31, 2013, a net regulatory asset of $173 million and $182 million, respectively, was recorded related to the net derivative liability of $116 million and $128 million, respectively.

Not Designated as Hedging Contracts

The following table reconciles the beginning and ending balances of the Company's net regulatory assets and summarizes the pre-tax gains and losses on commodity derivative contracts recognized in net regulatory assets, as well as amounts reclassified to earnings (in millions):

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2014	2013	2014	2013
Beginning balance	$ 142	$ 172	$ 182	$ 235
Changes in fair value recognized in net regulatory assets	37	18	30	12
Net gains (losses) reclassified to operating revenue	5	7	(30)	9
Net losses reclassified to cost of sales	(11)	(53)	(9)	(112)
Ending balance	$ 173	$ 144	$ 173	$ 144

Designated as Hedging Contracts

The Company uses commodity derivative contracts accounted for as cash flow hedges to hedge electricity and natural gas commodity prices for delivery to nonregulated customers, spring operational sales, natural gas storage and other transactions. The following table reconciles the beginning and ending balances of the Company's accumulated other comprehensive (income) loss (pre-tax) and summarizes pre-tax gains and losses on commodity derivative contracts designated and qualifying as cash flow hedges recognized in other comprehensive income (loss) ("OCI"), as well as amounts reclassified to earnings (in millions):

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2014	2013	2014	2013
Beginning balance	$ (25)	$ 26	$ 12	$ 32
Changes in fair value recognized in OCI	16	1	(61)	1
Net (losses) gains reclassified to cost of sales	(5)	(1)	35	(7)
Ending balance	$ (14)	$ 26	$ (14)	$ 26

Certain derivative contracts, principally interest rate locks, have settled and the fair value at the date of settlement remains in AOCI and is recognized in earnings when the forecasted transactions impact earnings. Realized gains and losses on hedges and hedge ineffectiveness are recognized in income as operating revenue, cost of sales, operating expense or interest expense depending upon the nature of the item being hedged. For the three- and nine-month periods ended September 30, 2014 and 2013, hedge ineffectiveness was insignificant. As of September 30, 2014, the Company had cash flow hedges with expiration dates extending through December 2019 and $13 million of pre-tax net unrealized gains are forecasted to be reclassified from AOCI into earnings over the next twelve months as contracts settle.

Derivative Contract Volumes

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

	Unit of Measure	September 30, 2014	December 31, 2013
Electricity sales	Megawatt hours	—	(5)
Natural gas purchases	Decatherms	346	322
Fuel purchases	Gallons	1	9
Interest rate swaps	US$	446	650
Mortgage sale commitments, net	US$	(94)	(121)

Credit Risk

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

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

MidAmerican Energy also has potential indirect credit exposure to other market participants in the regional transmission organization markets where it actively participates, including the Midcontinent Independent System Operator, Inc. and the PJM Interconnection, L.L.C.

Collateral and Contingent Features

In accordance with industry practice, certain wholesale derivative contracts contain credit support provisions that in part base certain collateral requirements on credit ratings for senior unsecured debt as reported by one or more of the three recognized credit rating agencies. These derivative contracts may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance," or in some cases terminate the contract, in the event of a material adverse change in creditworthiness. These rights can vary by contract and by counterparty. As of September 30, 2014, the applicable credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of the Company's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $145 million and $176 million as of September 30, 2014 and December 31, 2013, respectively, for which the Company had posted collateral of $8 million and $12 million, respectively, in the form of cash deposits. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of September 30, 2014 and December 31, 2013, the Company would have been required to post $116 million and $147 million, respectively, of additional collateral. The Company's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors.

(10) Fair Value Measurements

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

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

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

	Input Levels for Fair Value Measurements				
	Level 1	**Level 2**	**Level 3**	**Other**[1]	**Total**
As of September 30, 2014					
Assets:					
Commodity derivatives	$ —	$ 55	$ 70	$ (46)	$ 79
Interest rate derivatives	—	7	—	—	7
Mortgage loans held for sale	—	112	—	—	112
Money market mutual funds[2]	744	—	—	—	744
Debt securities:					
United States government obligations	136	—	—	—	136
International government obligations	—	1	—	—	1
Corporate obligations	—	37	—	—	37
Municipal obligations	—	2	—	—	2
Agency, asset and mortgage-backed obligations	—	2	—	—	2
Auction rate securities	—	—	45	—	45
Equity securities:					
United States companies	226	—	—	—	226
International companies	1,499	—	—	—	1,499
Investment funds	139	—	—	—	139
	$ 2,744	$ 216	$ 115	$ (46)	$ 3,029
Liabilities:					
Commodity derivatives	$ (2)	$ (180)	$ (49)	$ 92	$ (139)
Interest rate derivatives	—	(7)	—	—	(7)
	$ (2)	$ (187)	$ (49)	$ 92	$ (146)

	Input Levels for Fair Value Measurements				
	Level 1	Level 2	Level 3	Other[(1)]	Total
As of December 31, 2013					
Assets:					
Commodity derivatives	$ 3	$ 28	$ 69	$ (27)	$ 73
Interest rate derivatives	—	14	—	—	14
Mortgage loans held for sale	—	130	—	—	130
Money market mutual funds[(2)]	809	—	—	—	809
Debt securities:					
United States government obligations	134	—	—	—	134
International government obligations	—	1	—	—	1
Corporate obligations	—	38	—	—	38
Municipal obligations	—	2	—	—	2
Agency, asset and mortgage-backed obligations	—	2	—	—	2
Auction rate securities	—	—	44	—	44
Equity securities:					
United States companies	214	—	—	—	214
International companies	1,107	—	—	—	1,107
Investment funds	114	—	—	—	114
	$ 2,381	$ 215	$ 113	$ (27)	$ 2,682
Liabilities:					
Commodity derivatives	$ (1)	$ (230)	$ (9)	$ 39	$ (201)
Interest rate derivatives	—	(7)	—	—	(7)
	$ (1)	$ (237)	$ (9)	$ 39	$ (208)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $46 million and $12 million as of September 30, 2014 and December 31, 2013, respectively.

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

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which the Company transacts. When quoted prices for identical contracts are not available, the Company uses forward price curves. Forward price curves represent the Company's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. The Company bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent brokers, exchanges, direct communication with market participants and actual transactions executed by the Company. Market price quotations are generally readily obtainable for the applicable term of the Company's outstanding derivative contracts; therefore, the Company's forward price curves reflect observable market quotes. Market price quotations for certain electricity and natural gas trading hubs are not as readily obtainable due to the length of the contract. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, the Company uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts. Refer to Note 9 for further discussion regarding the Company's risk management and hedging activities.

The Company's mortgage loans held for sale are valued based on independent quoted market prices, where available, or the prices of other mortgage whole loans with similar characteristics. As necessary, these prices are adjusted for typical securitization activities, including servicing value, portfolio composition, market conditions and liquidity.

The Company's investments in money market mutual funds and debt and equity securities are accounted for as available-for-sale securities and are stated at fair value. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics. The fair value of the Company's investments in auction rate securities, where there is no current liquid market, is determined using pricing models based on available observable market data and the Company's judgment about the assumptions, including liquidity and nonperformance risks, which market participants would use when pricing the asset.

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

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	Commodity Derivatives	Auction Rate Securities	Commodity Derivatives	Auction Rate Securities
2014:				
Beginning balance	$ 9	$ 46	$ 60	$ 44
Changes included in earnings	17	—	(4)	—
Changes in fair value recognized in OCI	—	(1)	4	1
Changes in fair value recognized in net regulatory assets	(3)	—	(3)	—
Settlements	(2)	—	(1)	—
Transfers from level 2	—	—	(35)	—
Ending balance	$ 21	$ 45	$ 21	$ 45
2013:				
Beginning balance	$ 27	$ 42	$ 32	$ 41
Changes included in earnings	12	—	16	—
Changes in fair value recognized in OCI	—	1	(5)	2
Changes in fair value recognized in net regulatory assets	(1)	—	1	—
Purchases	—	—	2	—
Settlements	1	—	(7)	—
Ending balance	$ 39	$ 43	$ 39	$ 43

The Company's long-term debt is carried at cost on the Consolidated Financial Statements. The fair value of the Company's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of the Company's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of the Company's long-term debt (in millions):

	As of September 30, 2014		As of December 31, 2013	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 32,064	$ 36,421	$ 32,012	$ 34,881

(11) Commitments and Contingencies

Legal Matters

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

USA Power

In October 2005, prior to BHE's ownership of PacifiCorp, PacifiCorp was added as a defendant to a lawsuit originally filed in February 2005 in the Third District Court of Salt Lake County, Utah ("Third District Court") by USA Power, LLC, USA Power Partners, LLC and Spring Canyon Energy, LLC (collectively, the "Plaintiff"). The Plaintiff's complaint alleged that PacifiCorp misappropriated confidential proprietary information in violation of Utah's Uniform Trade Secrets Act and accused PacifiCorp of breach of contract and related claims in regard to the Plaintiff's 2002 and 2003 proposals to build a natural gas-fueled generating facility in Juab County, Utah. In October 2007, the Third District Court granted PacifiCorp's motion for summary judgment on all counts and dismissed the Plaintiff's claims in their entirety. In February 2008, the Plaintiff filed a petition requesting consideration by the Utah Supreme Court. In May 2010, the Utah Supreme Court reversed summary judgment and remanded the case back to the Third District Court for further consideration, which led to a trial that began in April 2012. In May 2012, the jury reached a verdict in favor of the Plaintiff on its claims. The jury awarded damages to the Plaintiff for breach of contract and misappropriation of a trade secret in the amounts of $18 million for actual damages and $113 million for unjust enrichment. In May 2012, the Plaintiff filed a motion seeking exemplary damages. Under the Utah Uniform Trade Secrets law, the judge may award exemplary damages in an additional amount not to exceed twice the original award. The Plaintiff also filed a motion to seek recovery of attorneys' fees in an amount equal to 40% of all amounts ultimately awarded in the case. In October 2012, PacifiCorp filed post-trial motions for a judgment notwithstanding the verdict and a new trial (collectively, "PacifiCorp's post-trial motions"). The trial judge stayed briefing on the Plaintiff's motions, pending resolution of PacifiCorp's post-trial motions. As a result of a hearing in December 2012, the trial judge denied PacifiCorp's post-trial motions with the exception of reducing the aggregate amount of damages to $113 million. In January 2013, the Plaintiff filed a motion for prejudgment interest. In the first quarter of 2013, PacifiCorp filed its responses to the Plaintiff's post-trial motions for exemplary damages, attorneys' fees and prejudgment interest. An initial judgment was entered in April 2013 in which the trial judge denied the Plaintiff's motions for exemplary damages and prejudgment interest and ruled that PacifiCorp must pay the Plaintiff's attorneys' fees based on applying a reasonable rate to hours worked rather than the Plaintiff's request for an amount equal to 40% of all amounts ultimately awarded. In May 2013, a final judgment was entered against PacifiCorp in the amount of $115 million, which includes the $113 million of aggregate damages previously awarded and amounts awarded for the Plaintiff's attorneys' fees. The final judgment also ordered that postjudgment interest accrue beginning as of the date of the April 2013 initial judgment. In May 2013, PacifiCorp posted a surety bond issued by a subsidiary of Berkshire Hathaway to secure its estimated obligation. PacifiCorp strongly disagrees with the jury's verdict and is vigorously pursuing all appellate measures. Both PacifiCorp and the Plaintiff filed appeals with the Utah Supreme Court. Briefing before the Utah Supreme Court is complete and oral arguments will most likely be held in 2015. As of September 30, 2014, PacifiCorp had accrued $118 million for the final judgment and postjudgment interest, and believes the likelihood of any additional material loss is remote; however, any additional awards against PacifiCorp could also have a material effect on the consolidated financial results. Any payment of damages will be at the end of the appeals process, which could take as long as several years.

Commitments

The Topaz Project, which is a 550-MW solar project in California, and the Solar Star Projects, which are a combined 579-MW solar project in California, are in construction and are being placed in-service in phases in 2014 and 2015. BHE has committed to separately provide Topaz Solar Farms LLC and Solar Star Funding, LLC and its subsidiaries with equity to fund the costs of the projects in an amount up to $2.44 billion for the Topaz Project and $2.75 billion for the Solar Star Projects, less, among other things, the gross proceeds of long-term debt issuances, project revenue prior to completion and the total equity contributions made by BHE or its subsidiaries. As of September 30, 2014, the remaining equity commitment for the Topaz Project is $550 million and for the Solar Star Projects is $1.19 billion. If BHE does not maintain a minimum credit rating from two of the following three ratings agencies of at least BBB- from Standard & Poor's Ratings Services or Fitch Ratings or Baa3 from Moody's Investors Service, BHE's obligations under the equity commitment agreements would be supported by cash collateral or a letter of credit issued by a financial institution that meets certain minimum criteria specified in the respective financing documents. Upon reaching the final commercial operation date of the Topaz and Solar Star Projects, respectively, BHE will have no further obligation to make any equity contributions and any unused equity contribution obligations will be canceled under each project's respective equity commitment agreement.

Environmental Laws and Regulations

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

Guarantees

The Company has entered into guarantees as part of the normal course of business and the sale of certain assets. These guarantees are not expected to have a material impact on the Company's consolidated financial results.

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

The following table shows the change in AOCI attributable to BHE shareholders by each component of OCI, net of applicable income taxes (in millions):

	Unrecognized Amounts on Retirement Benefits	Foreign Currency Translation Adjustment	Unrealized Gains on Available-For-Sale Securities	Unrealized Gains on Cash Flow Hedges	AOCI Attributable To BHE Shareholders, Net
Balance, December 31, 2012	$ (575)	$ (172)	$ 261	$ 23	$ (463)
Other comprehensive income (loss)	36	(1)	200	5	240
Balance, September 30, 2013	$ (539)	$ (173)	$ 461	$ 28	$ (223)
Balance, December 31, 2013	$ (559)	$ (98)	$ 524	$ 36	$ (97)
Other comprehensive income (loss)	44	(83)	236	13	210
Balance, September 30, 2014	$ (515)	$ (181)	$ 760	$ 49	$ 113

Reclassifications from AOCI to net income for the periods ended September 30, 2014 and 2013 were insignificant. For information regarding cash flow hedge reclassifications from AOCI to net income in their entirety, refer to Note 9. Additionally, refer to the "Foreign Operations" discussion in Note 8 for information about unrecognized amounts on retirement benefits reclassifications from AOCI that do not impact net income in their entirety.

(13) Segment Information

The Company's reportable segments with foreign operations include Northern Powergrid Holdings, whose business is principally in Great Britain, and MidAmerican Renewables, whose business includes operations in the Philippines. Intersegment eliminations and adjustments, including the allocation of goodwill, have been made. Information related to the Company's reportable segments is shown below (in millions):

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2014	2013	2014	2013
Operating revenue:				
PacifiCorp	$ 1,438	$ 1,398	$ 3,969	$ 3,845
MidAmerican Funding	864	828	2,869	2,508
NV Energy	1,118	—	2,551	—
Pipelines	188	194	800	685
Northern Powergrid Holdings	306	243	947	796
MidAmerican Renewables	244	116	458	246
HomeServices	644	555	1,619	1,340
BHE and Other[1]	(28)	(1)	(87)	(32)
Total operating revenue	$ 4,774	$ 3,333	$ 13,126	$ 9,388
Depreciation and amortization:				
PacifiCorp	$ 189	$ 173	$ 555	$ 518
MidAmerican Funding	89	98	259	309
NV Energy	96	—	283	—
Pipelines	48	45	146	142
Northern Powergrid Holdings	52	44	150	129
MidAmerican Renewables	47	18	100	51
HomeServices	8	12	23	23
BHE and Other[1]	(2)	—	(5)	(6)
Total depreciation and amortization	$ 527	$ 390	$ 1,511	$ 1,166
Operating income:				
PacifiCorp	$ 419	$ 392	$ 1,054	$ 1,005
MidAmerican Funding	161	130	365	279
NV Energy	396	—	682	—
Pipelines	59	71	318	309
Northern Powergrid Holdings	158	112	517	424
MidAmerican Renewables	143	81	252	151
HomeServices	62	53	101	117
BHE and Other[1]	(23)	(21)	(64)	(53)
Total operating income	1,375	818	3,225	2,232
Interest expense	(423)	(309)	(1,266)	(893)
Capitalized interest	20	18	71	58
Allowance for equity funds	23	17	75	55
Other, net	18	14	59	54
Total income before income tax expense and equity income	$ 1,013	$ 558	$ 2,164	$ 1,506

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2014	2013	2014	2013
Interest expense:				
PacifiCorp	$ 96	$ 98	$ 291	$ 293
MidAmerican Funding	50	42	147	124
NV Energy	70	—	211	—
Pipelines	19	19	57	60
Northern Powergrid Holdings	38	35	114	105
MidAmerican Renewables	46	40	128	96
HomeServices	1	—	3	1
BHE and Other[(1)]	103	75	315	214
Total interest expense	$ 423	$ 309	$ 1,266	$ 893

	As of	
	September 30, 2014	December 31, 2013
Total assets:		
PacifiCorp	$ 23,068	$ 22,885
MidAmerican Funding	15,013	13,992
NV Energy	14,672	14,233
Pipelines	4,845	4,908
Northern Powergrid Holdings	7,151	6,874
MidAmerican Renewables	5,517	3,875
HomeServices	1,469	1,381
BHE and Other[(1)]	2,287	1,852
Total assets	$ 74,022	$ 70,000

(1) The differences between the reportable segment amounts and the consolidated amounts, described as BHE and Other, relate to corporate functions, MidAmerican Transmission, LLC, other corporate entities and intersegment eliminations.

The following table shows the change in the carrying amount of goodwill by reportable segment for the nine-month period ended September 30, 2014 (in millions):

	PacifiCorp	MidAmerican Funding	NV Energy	Pipelines	Northern Powergrid Holdings	MidAmerican Renewables	Home-Services	Other	Total
Balance, December 31, 2013	$ 1,129	$ 2,102	$ 2,280	$ 153	$ 1,149	$ 15	$ 695	$ 4	$ 7,527
Acquisitions	—	—	83	—	—	93	39	—	215
Foreign currency translation	—	—	—	—	(16)	—	—	—	(16)
Other	—	—	—	(19)	—	—	—	(1)	(20)
Balance, September 30, 2014	$ 1,129	$ 2,102	$ 2,363	$ 134	$ 1,133	$ 108	$ 734	$ 3	$ 7,706

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

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of the Company during the periods included herein. Explanations include management's best estimate of the impact of weather, customer growth and other factors. This discussion should be read in conjunction with the Company's historical unaudited Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q. The Company's actual results in the future could differ significantly from the historical results.

The Company's operations are organized and managed as ten distinct platforms: PacifiCorp, MidAmerican Funding (which primarily consists of MidAmerican Energy), NV Energy (which primarily consists of Nevada Power and Sierra Pacific), Northern Natural Gas, Kern River, Northern Powergrid Holdings (which primarily consists of Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc), MidAmerican Transmission, LLC (which owns a 50% interest in ETT and Electric Transmission America, LLC), MidAmerican Renewables, LLC (which owns interests in independent power projects in the United States), CalEnergy Philippines (which owns a majority interest in the Casecnan project in the Philippines), and HomeServices. Through these platforms, the Company owns four utility companies in the United States serving customers in 11 states, two interstate natural gas pipeline companies in the United States, two electricity distribution companies in Great Britain, a 50% interest in electric transmission businesses, a diversified portfolio of independent power projects, the second largest residential real estate brokerage firm in the United States and the second largest residential real estate brokerage franchise network in the United States. Northern Natural Gas and Kern River have been aggregated in the reportable segment called Pipelines, MidAmerican Renewables, LLC and CalEnergy Philippines have been aggregated in the reportable segment called MidAmerican Renewables and MidAmerican Transmission, LLC has been included in "BHE and Other". The reportable segment financial information includes all necessary adjustments and eliminations needed to conform to the Company's significant accounting policies. The differences between the reportable segment amounts and the consolidated amounts, described as BHE and Other, relate to corporate functions, MidAmerican Transmission, LLC, other corporate entities and intersegment eliminations.

Results of Operations for the Third Quarter and First Nine Months of 2014 and 2013

Overview

Net income for the Company's reportable segments is summarized as follows (in millions):

	Third Quarter				First Nine Months			
	2014	2013	Change		2014	2013	Change	
Net income attributable to BHE shareholders:								
PacifiCorp	$ 239	$ 217	$ 22	10%	$ 579	$ 542	$ 37	7%
MidAmerican Funding	168	143	25	17	353	264	89	34
NV Energy	213	—	213	*	318	—	318	*
Pipelines	27	33	(6)	(18)	166	161	5	3
Northern Powergrid Holdings	94	116	(22)	(19)	315	302	13	4
MidAmerican Renewables	69	41	28	68	100	70	30	43
HomeServices	34	30	4	13	55	69	(14)	(20)
BHE and Other	(68)	(55)	(13)	(24)	(190)	(134)	(56)	(42)
Total net income attributable to BHE shareholders	$ 776	$ 525	$ 251	48	$ 1,696	$ 1,274	$ 422	33

* Not meaningful

Net income attributable to BHE shareholders increased $251 million for the third quarter of 2014 compared to 2013 due to the following:

- PacifiCorp's net income increased due to higher retail prices and lower energy costs, partially offset by higher depreciation due to the impacts of a depreciation rate study effective in 2014 and higher plant in-service, lower wholesale volumes and lower renewable energy credit revenue.
- MidAmerican Funding's net income increased due to higher regulated electric margins from higher electric rates in Iowa, lower depreciation due to the impact of depreciation rate changes and higher AFUDC, partially offset by higher operating and interest expense.

- NV Energy was acquired in December 2013, and its results are included in the consolidated results beginning as of that date. Net income for the third quarter of 2014 totaled $213 million.
- Pipelines' net income decreased due to lower transportation revenue at Northern Natural Gas, higher operating expense due to higher maintenance costs and higher depreciation and amortization.
- Northern Powergrid's net income decreased due to deferred income tax benefits in 2013 of $54 million from reductions in the United Kingdom corporate income tax rate, partially offset by higher tariff rates, net favorable movements in regulatory provisions and the weaker United States dollar of $8 million.
- MidAmerican Renewables' net income increased due to higher earnings from the Topaz and Solar Star Projects as additional solar capacity was placed in-service and favorable earnings from the acquisition of the remaining 50% interest in CE Generation in June 2014, partially offset by lower earnings at the Casecnan Project due to lower revenue earned in 2014 from lower rainfall.
- HomeServices' net income increased due to earnings at newly acquired businesses, partially offset by lower earnings at existing mortgage businesses due to lower overall real estate purchase and refinancing activity.
- BHE and Other net loss increased due to higher interest expense from debt issuances in the fourth quarter of 2013, partially offset by higher equity earnings at ETT from continued investment and additional plant placed in-service.

Net income attributable to BHE shareholders increased $422 million for the first nine months of 2014 compared to 2013 due to the following:

- PacifiCorp's net income increased due to higher retail prices, the recognition of insurance recoveries for a fire claim and higher average wholesale prices, partially offset by higher energy costs, higher depreciation due primarily to the impacts of a depreciation rate study effective in 2014 and higher plant in-service, lower retail customer load and higher operating expense.
- MidAmerican Funding's net income increased due to higher regulated electric margins from higher electric rates in Iowa and higher natural gas margins from colder winter temperatures in 2014, lower depreciation from the impact of depreciation rate changes and higher AFUDC, partially offset by lower electric margins from cooler summer temperatures in 2014, higher operating and interest expense.
- NV Energy was acquired in December 2013, and its results are included in the consolidated results beginning as of that date. Net income for the first nine months of 2014 totaled $318 million.
- Pipelines' net income increased due to higher transportation revenue at Northern Natural Gas, partially offset by higher operating expense primarily at Northern Natural Gas, benefits from a contract restructuring in 2013 at Northern Natural Gas of $8 million and lower operating revenue at Kern River.
- Northern Powergrid's net income increased due to higher tariff rates and the weaker United States dollar of $25 million, partially offset by deferred income tax benefits in 2013 of $54 million from reductions in the United Kingdom corporate income tax rate, lower distributed units, higher operating expense and higher depreciation due to higher distribution assets placed in-service.
- MidAmerican Renewables' net income increased due to higher earnings from the Topaz and Solar Star Projects as additional solar capacity was placed in-service and favorable earnings from the acquisition of the remaining 50% interest in CE Generation in June 2014, partially offset by an unfavorable change in the valuation of the power purchase agreement derivative at Bishop Hill II, unfavorable changes in the valuation of the interest rate swaps at the Pinyon Pines Projects and lower earnings at the Casecnan Project due to lower revenue earned in 2014 from lower rainfall.
- HomeServices' net income decreased as earnings at newly acquired businesses were more than offset by lower earnings at existing brokerage, mortgage and franchise businesses due to lower units, lower overall real estate purchase and refinancing activity and higher operating expense.
- BHE and Other net loss increased due to higher interest expense from debt issuances in the fourth quarter of 2013, partially offset by higher equity earnings at ETT from continued investment and additional plant placed in-service.

Reportable Segment Results

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

	Third Quarter				First Nine Months			
	2014	2013	Change		2014	2013	Change	
Operating revenue:								
PacifiCorp	$ 1,438	$ 1,398	$ 40	3%	$ 3,969	$ 3,845	$ 124	3%
MidAmerican Funding	864	828	36	4	2,869	2,508	361	14
NV Energy	1,118	—	1,118	*	2,551	—	2,551	*
Pipelines	188	194	(6)	(3)	800	685	115	17
Northern Powergrid Holdings	306	243	63	26	947	796	151	19
MidAmerican Renewables	244	116	128	*	458	246	212	86
HomeServices	644	555	89	16	1,619	1,340	279	21
BHE and Other	(28)	(1)	(27)	*	(87)	(32)	(55)	*
Total operating revenue	$ 4,774	$ 3,333	$ 1,441	43	$ 13,126	$ 9,388	$ 3,738	40
Operating income:								
PacifiCorp	$ 419	$ 392	$ 27	7%	$ 1,054	$ 1,005	$ 49	5%
MidAmerican Funding	161	130	31	24	365	279	86	31
NV Energy	396	—	396	*	682	—	682	*
Pipelines	59	71	(12)	(17)	318	309	9	3
Northern Powergrid Holdings	158	112	46	41	517	424	93	22
MidAmerican Renewables	143	81	62	77	252	151	101	67
HomeServices	62	53	9	17	101	117	(16)	(14)
BHE and Other	(23)	(21)	(2)	(10)	(64)	(53)	(11)	(21)
Total operating income	$ 1,375	$ 818	$ 557	68	$ 3,225	$ 2,232	$ 993	44

* Not meaningful

PacifiCorp

Operating revenue increased $40 million for the third quarter of 2014 compared to 2013 due to higher retail revenue of $52 million, partially offset by lower wholesale and other revenue of $12 million. The increase in retail revenue was due to higher prices of $49 million and higher retail customer loads of $3 million. Customer load increased 0.6% due to higher residential and commercial customer usage in Utah, higher industrial customer usage in Wyoming and higher average number of residential customers, substantially offset by the impacts of cooler weather on residential and commercial customers in Utah and irrigation customers in Idaho. Wholesale and other revenue decreased due to lower wholesale volumes of $7 million and lower renewable energy credit revenue of $7 million.

Operating income increased $27 million for the third quarter of 2014 compared to 2013 due to the higher operating revenue and $5 million of lower energy costs, partially offset by higher depreciation and amortization of $16 million due to the impact of a depreciation rate study effective in 2014 and higher plant in-service, including Lake Side 2, a 645-MW combined-cycle combustion turbine natural gas-fueled generating facility ("Lake Side 2") in May 2014. Energy costs decreased due to lower purchased electricity volumes and lower average cost of natural gas, partially offset by higher natural gas volumes related to Lake Side 2, higher average cost of coal and lower net deferrals of incurred net power costs.

Operating revenue increased $124 million for the first nine months of 2014 compared to 2013 due to higher retail revenue of $102 million and higher wholesale and other revenue of $22 million. The increase in retail revenue was due to higher prices of $118 million, partially offset by lower retail customer load of $16 million. Customer load decreased 0.2% due to the impacts of milder weather on residential and commercial customers primarily in Utah and irrigation customers in Idaho, partially offset by higher residential, commercial and industrial customer usage in Utah, higher average number of residential customers and higher irrigation customer usage primarily in Oregon. Wholesale and other revenue increased primarily due to higher average wholesale prices of $19 million, partially offset by lower wholesale volumes of $4 million and lower renewable energy credit revenue of $4 million.

Operating income increased $49 million for the first nine months of 2014 compared to 2013 due to the higher operating revenue and the recognition of insurance recoveries for fire claims, partially offset by higher energy costs of $62 million, higher depreciation and amortization of $37 million, due to the impact of a depreciation rate study effective in 2014 and higher plant in-service including Lake Side 2, and higher operating expense of $13 million. Energy costs increased due to higher natural gas volumes including Lake Side 2, higher average cost of coal, higher average cost of purchased electricity and higher transmission expense, partially offset by lower purchased electricity volumes, lower coal volumes and higher hydroelectric generation.

MidAmerican Funding

MidAmerican Funding's operating revenue and operating income are summarized as follows (in millions):

	Third Quarter				First Nine Months			
	2014	2013	Change		2014	2013	Change	
Operating revenue:								
Regulated electric	$ 539	$ 512	$ 27	5%	$ 1,415	$ 1,338	$ 77	6%
Regulated natural gas	99	98	1	1	746	555	191	34
Nonregulated and other	226	218	8	4	708	615	93	15
Total operating revenue	$ 864	$ 828	$ 36	4	$ 2,869	$ 2,508	$ 361	14
Operating income:								
Regulated electric	$ 163	$ 130	$ 33	25%	$ 294	$ 211	$ 83	39%
Regulated natural gas	(6)	(6)	—	—	49	43	6	14
Nonregulated and other	4	6	(2)	(33)	22	25	(3)	(12)
Total operating income	$ 161	$ 130	$ 31	24	$ 365	$ 279	$ 86	31

Regulated electric operating revenue increased $27 million for the third quarter of 2014 compared to 2013 due to higher retail revenue of $35 million, partially offset by lower wholesale and other revenue of $8 million. Retail revenue was higher due to $48 million from higher electric rates in Iowa and $9 million from higher recoveries of demand-side management program costs, partially offset by $22 million from a decrease in retail customer load. Customer load decreased 2.7% compared to 2013 due to significantly milder temperatures in 2014, partially offset by strong industrial growth which increased 8.3%. The increase in Iowa electric rates includes an increase in base rates, partially attributable to changes in rate structure related to seasonal pricing that result in higher rates from June to September and lower rates in the remaining months and new adjustment clauses for recovery of retail energy production and transmission costs. Wholesale revenue decreased due to lower volumes of $10 million, partially offset by higher average prices of $2 million.

Regulated electric operating income increased $33 million for the third quarter of 2014 compared to 2013 due to the higher regulated electric operating revenue, lower depreciation of $9 million due to the impact of depreciation rate changes and lower energy costs of $6 million from lower natural gas-fueled generation, partially offset by higher operating expense of $9 million from higher demand-side management program costs.

Nonregulated and other operating revenue increased $8 million for the third quarter of 2014 compared to 2013 due to higher electricity prices and volumes and higher natural gas prices, partially offset by lower natural gas volumes. Nonregulated and other operating income decreased $2 million for 2014 compared to 2013 due to lower electric margins.

Regulated electric operating revenue increased $77 million for the first nine months of 2014 compared to 2013 due to higher retail revenue of $89 million, partially offset by lower wholesale and other revenue of $12 million. Retail revenue was higher due to $75 million from higher electric rates in Iowa and $13 million from higher recoveries of demand-side management program costs. The increase in Iowa electric rates includes the increase in base rates implemented in August 2013 and, effective with the implementation of final base rates in August 2014, changes in rate structure related to seasonal pricing that result in higher rates from June to September and lower rates in the remaining months, and new adjustment clauses for recovery of retail energy production and transmission costs. Customer load increased 2.5% compared to 2013 as a result of strong industrial growth and colder winter temperatures in 2014, partially offset by milder summer temperatures. Wholesale revenue decreased due to lower volumes of $34 million primarily from the higher retail energy requirements and lower generation, partially offset by higher average prices of $19 million.

Regulated electric operating income increased $83 million for the first nine months of 2014 compared to 2013 due to the higher regulated electric operating revenue and $50 million of lower depreciation due to the impact of depreciation rate changes, partially offset by higher energy costs of $23 million, primarily due to higher purchased power costs and higher coal-fueled generation costs per unit, and higher operating expense of $22 million. Operating expense increased primarily due to higher demand-side management program costs of $13 million and higher transmission and distribution costs.

Regulated natural gas operating revenue increased $191 million for the first nine months of 2014 compared to 2013 due to an increase in recoveries through adjustment clauses from a higher average per-unit cost of gas sold of $163 million and higher sales volumes from the colder winter temperatures in 2014. Regulated natural gas operating income increased $6 million for the first nine months of 2014 compared to 2013 due to the higher sales volumes, partially offset by higher operating expense resulting from a one-time refund of $8 million to customers of insurance recoveries related to environmental matters.

Nonregulated and other operating revenue increased $93 million for the first nine months of 2014 compared to 2013 due to higher natural gas prices, higher electricity prices and volumes and higher construction services, partially offset by lower natural gas volumes. Nonregulated and other operating income decreased $3 million for the first nine months of 2014 compared to 2013 due to lower electric margins, partially offset by higher natural gas margins.

NV Energy

NV Energy was acquired in December 2013, and its results are included in the consolidated results beginning as of that date. Operating revenue for the third quarter of 2014 consisted of $1.1 billion of electric revenue and $18 million of natural gas revenue. Operating income for the third quarter of 2014 totaled $396 million.

Operating revenue for the first nine months of 2014 consisted of $2.5 billion of electric revenue and $83 million of natural gas revenue. Operating income totaled $682 million for the first nine months of 2014.

Pipelines

Operating revenue decreased $6 million for the third quarter of 2014 compared to 2013 due to lower operating revenue at Northern Natural Gas from both lower transportation revenue of $3 million on lower volumes and lower natural gas sales related to system balancing activities of $3 million. Operating income decreased $12 million for the third quarter of 2014 compared to 2013 due to higher operating expense of $7 million primarily at Northern Natural Gas due to higher maintenance costs, the lower transportation revenue at Northern Natural Gas and higher depreciation and amortization of $3 million.

Operating revenue increased $115 million for the first nine months of 2014 compared to 2013 due to higher operating revenue at Northern Natural Gas from both higher natural gas sales related to system balancing activities of $77 million and higher transportation revenue of $40 million on higher rates and volumes due to colder than normal temperatures and volatile natural gas prices during the first quarter of 2014, partially offset by lower operating revenue at Kern River of $7 million primarily due to contract expirations with capacity being sold at lower rates. Operating income increased $9 million for the first nine months of 2014 compared to 2013 due to the higher transportation revenue at Northern Natural Gas, partially offset by the lower operating revenue at Kern River and higher operating expense of $24 million primarily at Northern Natural Gas due to higher maintenance costs.

Northern Powergrid Holdings

Operating revenue increased $63 million for the third quarter of 2014 compared to 2013 due to higher distribution revenue of $40 million and the weaker United States dollar of $26 million. Distribution revenue increased due to higher tariff rates of $29 million and net favorable movements in regulatory provisions of $15 million, partially offset by a decrease in distributed units of $3 million. Operating income increased $46 million for the third quarter of 2014 compared to 2013 due to the higher distribution revenue, the weaker United States dollar of $13 million, the write-off of hydrocarbon well exploration costs in 2013 of $6 million and lower pension costs, partially offset by higher distribution costs and higher depreciation of $4 million due to higher distribution assets placed in-service.

Operating revenue increased $151 million for the first nine months of 2014 compared to 2013 due to the weaker United States dollar of $75 million, higher distribution revenue of $67 million and higher contracting revenue of $14 million. Distribution revenue increased due to higher tariff rates of $82 million and net favorable movements in regulatory provisions of $6 million, partially offset by a decrease in distributed units of $18 million. Operating income increased $93 million for the first nine months of 2014 compared to 2013 due to the higher distribution revenue, the weaker United States dollar of $41 million, lower pension costs of $11 million and the write-off of hydrocarbon well exploration costs in 2013 of $6 million, partially offset by higher distribution costs and higher depreciation of $9 million due to higher distribution assets placed in-service.

MidAmerican Renewables

Operating revenue increased $128 million for the third quarter of 2014 compared to 2013 due to the acquisition of the remaining 50% interest in CE Generation in June 2014 of $77 million and an increase from the Topaz and Solar Star Projects of $61 million as additional solar capacity was placed in-service, partially offset by lower variable energy fees earned in 2014 at the Casecnan Project of $7 million from lower rainfall. Operating income increased $62 million for the third quarter of 2014 compared to 2013 due to $22 million from the CE Generation acquisition and the other changes in operating revenue, partially offset by higher depreciation of $10 million primarily from additional solar capacity placed in-service.

Operating revenue increased $212 million for the first nine months of 2014 compared to 2013 due to an increase from the Topaz and Solar Star Projects of $131 million as additional solar capacity was placed in-service and an increase of $103 million from the CE Generation acquisition, partially offset by a higher loss from the change in the valuation of the power purchase agreement derivative at Bishop Hill II of $14 million and lower variable energy fees earned in 2014 at the Casecnan Project of $7 million from lower rainfall. Operating income increased $101 million for the first nine months of 2014 compared to 2013 due to $31 million from the CE Generation acquisition and the other changes in operating revenue, partially offset by higher operating expense of $15 million and higher depreciation of $24 million from additional solar capacity placed in-service.

HomeServices

Operating revenue increased $89 million for the third quarter of 2014 compared to 2013 due to a 4.5% increase in closed brokerage units and a 14.2% increase in average home sales prices. An increase from acquired businesses totaling $105 million was partially offset by a decrease from existing businesses totaling $16 million. The decrease in existing businesses reflects a 7.4% decrease in closed brokerage units, partially offset by a 6.0% increase in average home sales prices. Operating income increased $9 million for the third quarter of 2014 compared to 2013 due to higher earnings at acquired businesses of $15 million, partially offset by lower earnings of $6 million primarily at existing franchise businesses, due to lower closed brokerage units and Berkshire Hathaway HomeServices rebranding activities, and mortgage businesses due to lower overall real estate purchase and refinancing activity.

Operating revenue increased $279 million for the first nine months of 2014 compared to 2013 due to a 9.4% increase in closed brokerage units and an 11.7% increase in average home sales price. An increase from newly acquired businesses totaling $330 million was partially offset by a decrease from existing businesses totaling $51 million. The decrease in existing businesses reflects an 8.0% decrease in closed brokerage units, partially offset by a 5.7% increase in average home sales prices. Operating income decreased $16 million for the first nine months of 2014 compared to 2013 as the earnings at newly acquired businesses of $17 million were more than offset by lower earnings of $33 million primarily at existing brokerage and franchise businesses due to lower closed brokerage units and higher operating expense largely from Berkshire Hathaway HomeServices rebranding activities at the franchise businesses and mortgage businesses due to lower overall real estate purchase and refinancing activity.

BHE and Other

Operating revenue decreased $27 million for the third quarter of 2014 compared to 2013 and $55 million for the first nine months of 2014 compared to 2013 due to higher intersegment eliminations related to the acquisition of NV Energy in December 2013. Operating loss increased $2 million for the third quarter of 2014 compared to 2013 and $11 million for the first nine months of 2014 compared to 2013 due to higher operating expense.

Consolidated Other Income and Expense Items

Interest Expense

Interest expense is summarized as follows (in millions):

	Third Quarter				First Nine Months			
	2014	**2013**	**Change**		**2014**	**2013**	**Change**	
Subsidiary debt	$ 319	$ 233	$ 86	37%	$ 948	$ 672	$ 276	41%
BHE senior debt and other	87	76	11	14	262	221	41	19
BHE junior subordinated debentures	17	—	17	*	56	—	56	*
Total interest expense	$ 423	$ 309	$ 114	37	$ 1,266	$ 893	$ 373	42

* Not meaningful

Interest expense on subsidiary debt increased $86 million for the third quarter of 2014 compared to 2013 and $276 million for the first nine months of 2014 compared to 2013 due to $70 million and $211 million, respectively, from the acquisition of NV Energy in December 2013, and $4 million and $5 million, respectively, from the acquisition of the remaining 50% interest in CE Generation in June 2014. Additionally, debt issuances at MidAmerican Funding ($950 million in September 2013 and $850 million in April 2014) and MidAmerican Renewables ($250 million in April 2013 and $1.0 billion in June 2013) and the impact of the foreign currency exchange rate of $3 million for the third quarter and $9 million for the first nine months of 2014 increased interest expense, partially offset by scheduled maturities and principal payments.

Interest expense on BHE senior debt increased $11 million for the third quarter of 2014 compared to 2013 and $41 million for the first nine months of 2014 compared to 2013 due to the issuance of $2.0 billion of BHE senior debt in November 2013.

Interest expense on the BHE junior subordinated debentures relates to the $2.6 billion of BHE junior subordinated debentures issued to certain Berkshire Hathaway subsidiaries in December 2013. In June 2014, BHE repaid at par value $300 million, plus accrued interest, of its junior subordinated debentures due December 2043.

Capitalized Interest

Capitalized interest increased $2 million for the third quarter of 2014 compared to 2013 primarily due to higher construction work-in-progress balances related to additional wind-powered generation at MidAmerican Energy and MidAmerican Renewables, partially offset by lower construction work-in-progress balances related to the Topaz Project.

Capitalized interest increased $13 million for the first nine months of 2014 compared to 2013 primarily due to higher construction work-in-progress balances related to the Solar Star Projects and additional wind-powered generation at MidAmerican Energy, partially offset by lower construction work-in-progress balances related to the Topaz Project.

Allowance for Equity Funds

Allowance for equity funds increased $6 million for the third quarter of 2014 compared to 2013 and $20 million for the first nine months of 2014 compared to 2013 primarily due to higher construction work-in-progress balances related to additional wind-powered generation at MidAmerican Energy, partially offset by lower construction work-in-progress balances at PacifiCorp.

Other, net

Other, net increased $4 million for the third quarter of 2014 compared to 2013 and $5 million for the first nine months of 2014 compared to 2013 due to the acquisition of NV Energy in December 2013 and higher charitable contributions in 2013 of $5 million, partially offset by lower Rabbi Trust performance, an unfavorable movement on the Pinyon Pines interest rate swaps and benefits from a contract restructuring at Northern Natural Gas of $12 million in the second quarter of 2013.

Income Tax Expense

Income tax expense increased $217 million for the third quarter of 2014 compared to 2013 and the effective tax rates were 26% for 2014 and 9% for 2013. The effective tax rate increased due to deferred income tax benefits in 2013 of $54 million from reductions in the United Kingdom corporate income tax rate, higher pre-tax earnings including the acquisition of NV Energy in December 2013, additional state income taxes of $9 million and less favorable impacts of ratemaking of $9 million, partially offset by higher production tax credits of $5 million in 2014.

Income tax expense increased $259 million for the first nine months of 2014 compared to 2013 and the effective tax rates were 25% for 2014 and 18% for 2013. The effective tax rate increased due to deferred income tax benefits in 2013 of $54 million from reductions in the United Kingdom corporate income tax rate, higher pre-tax earnings including the acquisition of NV Energy, additional state income taxes of $14 million and less favorable impacts of ratemaking of $12 million, partially offset by higher production tax credits of $30 million in 2014.

In the third quarter of 2013, the Company recognized $54 million of deferred income tax benefits upon the enactment of a reduction in the United Kingdom corporate income tax rate from 23% to 21% effective April 1, 2014, and a further reduction to 20% effective April 1, 2015.

Equity Income

Equity income is summarized as follows (in millions):

	Third Quarter				First Nine Months			
	2014	2013	Change		2014	2013	Change	
ETT	$ 22	$ 9	$ 13	*%	$ 59	$ 33	$ 26	79%
Agua Caliente	14	13	1	8	25	25	—	—
HomeServices Lending	—	2	(2)	(100)	1	10	(9)	(90)
CE Generation	—	2	(2)	(100)	(8)	(4)	(4)	(100)
Other	2	2	—	—	7	4	3	75
Total equity income	$ 38	$ 28	$ 10	36	$ 84	$ 68	$ 16	24

* Not meaningful

Equity income increased $10 million for the third quarter of 2014 compared to 2013 and $16 million for the first nine months of 2014 compared to 2013 due to higher equity earnings at ETT from continued investment and additional plant placed in-service, partially offset by lower equity earnings at the HomeServices mortgage joint venture due to lower refinancing activity and lower equity earnings at CE Generation as BHE acquired the remaining interest in CE Generation in June 2014.

Liquidity and Capital Resources

Each of BHE's direct and indirect subsidiaries is organized as a legal entity separate and apart from BHE and its other subsidiaries. It should not be assumed that the assets of any subsidiary will be available to satisfy BHE's obligations or the obligations of its other subsidiaries. However, unrestricted cash or other assets that are available for distribution may, subject to applicable law, regulatory commitments and the terms of financing and ring-fencing arrangements for such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to BHE or affiliates thereof. The long-term debt of subsidiaries may include provisions that allow BHE's subsidiaries to redeem such debt in whole or in part at any time. These provisions generally include make-whole premiums. Refer to Note 17 of Notes to Consolidated Financial Statements in Item 8 of the Company's Annual Report on Form 10-K for the year ended December 31, 2013 for further discussion regarding the limitation of distributions from BHE's subsidiaries.

As of September 30, 2014, the Company's total net liquidity was $5.6 billion as follows (in millions):

	BHE	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid Holdings	Other	Total
Cash and cash equivalents	$ 73	$ 116	$ 397	$ 561	$ 2	$ 332	$ 1,481
Credit facilities[1]	2,000	1,200	609	650	298	603	5,360
Less:							
Short-term debt	(75)	—	—	—	(161)	(358)	(594)
Tax-exempt bond support and letters of credit	(28)	(412)	(195)	—	—	—	(635)
Net credit facilities	1,897	788	414	650	137	245	4,131
Total net liquidity	$ 1,970	$ 904	$ 811	$ 1,211	$ 139	$ 577	$ 5,612
Credit facilities:							
Maturity dates	2017	2017, 2018	2015, 2018	2018	2017	2014, 2015, 2018	
Largest single bank commitment as a % of total credit facilities	6%	7%	7%	12%	46%	25%	

(1) Includes the drawn uncommitted credit facilities totaling $54 million at Northern Powergrid Holdings.

Refer to Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-Q for further discussion regarding the Company's credit facilities.

Operating Activities

Net cash flows from operating activities for the nine-month periods ended September 30, 2014 and 2013 were $4.3 billion and $3.7 billion, respectively. Improved operating results, including NV Energy, were partially offset by higher interest payments, lower income tax receipts and other changes in working capital.

Investing Activities

Net cash flows from investing activities for the nine-month periods ended September 30, 2014 and 2013 were $(4.2) billion and $(3.6) billion, respectively. The change was primarily due higher capital expenditures, including NV Energy, and acquisitions totaling $246 million in 2014 for the remaining 50% interest in CE Generation, the Jumbo Road Project and a residential real estate brokerage business, partially offset by changes in restricted cash and investments primarily used to fund capital expenditures at the Solar Star Projects.

Financing Activities

Net cash flows from financing activities for the nine-month period ended September 30, 2014 was $148 million. Sources of cash totaled $1.6 billion related to proceeds from subsidiary debt issuances totaling $1.3 billion and net proceeds from short-term debt totaling $367 million. Uses of cash totaled $1.5 billion and consisted mainly of repayments of subsidiary debt totaling $884 million and repayments of BHE senior debt and junior subordinated debentures totaling $550 million.

In July 2014, NV Energy redeemed its $195 million variable-rate term loan due October 2014.

In June 2014, BHE repaid at par value $300 million, plus accrued interest, of its junior subordinated debentures due December 2043.

In April 2014, MidAmerican Energy issued $150 million of its 2.40% First Mortgage Bonds due March 2019, $300 million of its 3.50% First Mortgage Bonds due October 2024 and $400 million of its 4.40% First Mortgage Bonds due October 2044. The net proceeds were used for the optional redemption in May 2014 of $350 million of MidAmerican Energy's 4.65% Senior Notes due October 2014 and for general corporate purposes.

In March 2014, PacifiCorp issued $425 million of its 3.60% First Mortgage Bonds due April 2024. The net proceeds were used to fund capital expenditures and for general corporate purposes.

Net cash flows from financing activities for the nine-month period ended September 30, 2013 was $1.0 billion. Sources of cash totaled $2.5 billion related to proceeds from subsidiary debt issuances. Uses of cash totaled $1.4 billion and consisted mainly of net repayments of short-term debt totaling $919 million and repayments of subsidiary debt totaling $437 million.

Future Uses of Cash

The Company has available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, the issuance of equity and other sources. These sources are expected to provide funds required for current operations, capital expenditures, acquisitions, investments, debt retirements and other capital requirements. The availability and terms under which each subsidiary has access to external financing depends on a variety of factors, including its credit ratings, investors' judgment of risk and conditions in the overall capital markets, including the condition of the utility industry and project finance markets, among other items.

Capital Expenditures

The Company has significant future capital requirements. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, changes in environmental and other rules and regulations; impacts to customers' rates; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital. Prudently incurred expenditures for compliance-related items, such as pollution-control technologies, replacement generation, nuclear decommissioning, hydroelectric relicensing, hydroelectric decommissioning and associated operating costs are generally incorporated into BHE's energy subsidiaries' regulated retail rates. Expenditures for certain assets may ultimately include acquisitions of existing assets.

Historical and forecasted capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, by reportable segment are as follows (in millions):

	Nine-Month Periods Ended September 30,		Forecasted
	2013	2014	2014
Capital expenditures:			
PacifiCorp	$ 752	$ 777	$ 1,091
MidAmerican Funding	599	968	1,643
NV Energy	—	264	548
Pipelines	99	162	291
Northern Powergrid Holdings	487	479	670
MidAmerican Renewables	926	1,391	2,298
Other	22	19	31
Total	$ 2,885	$ 4,060	$ 6,572

The Company's historical and forecasted capital expenditures consisted mainly of the following:

- Transmission system investments at the Utilities for the nine-month periods ended September 30, 2014 and 2013 totaling $302 million and $203 million, respectively. The Utilities anticipate costs for transmission projects will total $453 million for 2014. Transmission system investment for 2014 include costs for PacifiCorp's 170-mile single-circuit 345-kV Sigurd-Red Butte transmission line expected to be placed in-service in 2015 and MidAmerican Energy's Multi-Value Projects approved by the MISO for the construction of 245 miles of 345 kV transmission line located in Iowa and Illinois.
- Emissions control equipment on existing generating facilities at the Utilities for the nine-month periods ended September 30, 2014 and 2013 totaling $201 million and $169 million, respectively, for installation or upgrade of control systems for nitrogen oxides, particulate matter, sulfur dioxide and mercury. The Utilities anticipate costs for emissions control equipment will total $245 million for 2014.
- The construction of PacifiCorp's Lake Side 2 645-MW combined-cycle combustion turbine natural gas-fueled generating facility ("Lake Side 2") for the nine-month periods ended September 30, 2014 and 2013 totaling $32 million and $116 million, respectively, which was placed in-service in May 2014.
- The construction of 1,050 MW (nominal ratings) of wind-powered generating facilities at MidAmerican Energy for the nine-month period ended September 30, 2014 and 2013 totaling $593 million and $158 million, respectively. MidAmerican Energy anticipates costs for wind-powered generating facilities will total $792 million for 2014. As of September 30, 2014, MidAmerican Energy has placed in-service 194 MW of wind-powered generating facilities and expects to place an additional 361 MW (nominal ratings) in-service in 2014 and 495 MW (nominal ratings) in-service in 2015.
- NV Energy anticipates costs for additional generation capacity will total $153 million for 2014.
- Topaz has spent $1.7 billion for construction of the Topaz Project from inception through September 30, 2014, and expects to spend an additional $398 million for the remainder of 2014 and $69 million for 2015. The project is expected to cost $2.44 billion, including all interest costs during construction and the initial costs to acquire the project. The project will be comprised of 22 blocks of solar panels with a nominal facilities capacity of 586 MW. As of September 30, 2014, 556 MW have been placed in-service under the construction contract, and 542 MW of the Topaz Project are operating and delivering energy under the power purchase agreement. Construction and commissioning are approximately four months ahead of schedule and Topaz expects the project to reach substantial completion in the fourth quarter of 2014, with final completion expected in March 2015. As of September 30, 2014, the project was 99% constructed compared to the engineering, procurement and construction schedule of 83%, and 100% of the 8.44 million solar panels have been installed. The project is being constructed pursuant to a fixed-price, date certain, turn-key engineering, procurement and construction contract with a subsidiary of First Solar.

- Subsidiaries of Solar Star Funding have spent \$1.5 billion for construction of the Solar Star Projects from inception through September 30, 2014, and expect to spend an additional \$361 million for the remainder of 2014 and \$758 million for 2015. The projects are expected to cost \$2.75 billion, including all interest costs during construction and the initial costs to acquire the projects. The projects will be comprised of 13 blocks of solar panels with a capacity of 579 MW. As of September 30, 2014, 389 MW of the Solar Star Projects are operating and delivering energy under the power purchase agreements, including 243 MW placed in-service under the construction contract. On October 1, 2014, an additional 56 MW were placed in-service under the construction contract bringing the total to 299 MW. Subsidiaries of Solar Star Funding expect to place an additional 54 MW in-service in 2014 and 226 MW in-service in 2015. As of September 30, 2014, the projects were approximately 80% constructed compared to the engineering, procurement and construction schedule of 72%, which includes 1.39 million solar panels installed out of an expected total of 1.72 million. The projects are being constructed pursuant to fixed-price, date certain, turn-key engineering, procurement and construction contracts with a subsidiary of SunPower Corporation.
- Jumbo Road has spent \$214 million for construction of the Jumbo Road Project through September 30, 2014, and expects to spend an additional \$123 million for the remainder of 2014 and \$31 million for 2015. The project is expected to cost \$408 million, including all interest costs during construction and the initial costs to acquire the project. The project will be comprised of 162 General Electric Company 1.85 MW wind turbines with a total capacity of 300 MW. On-site construction was initiated in 2013 and as of September 30, 2014, 39 foundations have been installed and four turbines have been erected. The project is being constructed pursuant to fixed-price agreements that include a turbine supply agreement with General Electric Company, a main power transformer purchase agreement with GE Prolec Transformers Inc. and a balance of plant construction contract with Blattner Energy, Inc. The project is expected to achieve commercial operation by the end of the first quarter 2015.
- Remaining costs relate to routine expenditures for transmission, distribution, generation and other infrastructure needed to serve existing and expected demand and totaled \$1.6 billion and \$1.3 billion for the nine-month periods ended September 30, 2014 and 2013, respectively. These expenditures for transmission, distribution, generation and other infrastructure needed to serve existing and expected demand are expected to total \$2.6 billion for 2014.

In October 2014, MidAmerican Energy filed with the IUB an application for ratemaking principles related to the construction of up to 162 MW (nominal ratings) of additional wind-powered generating facilities expected to be placed in-service by the end of 2015. The filing, which is subject to IUB approval, establishes a cost cap of \$279 million, including AFUDC, and provides for a fixed rate of return on equity of 11.75% over the proposed 30-year useful lives of the facilities in any future Iowa rate proceeding. The cost cap ensures that as long as total costs are below the cap, the investment will be deemed prudent in any future Iowa rate proceeding. MidAmerican Energy has requested IUB approval in early 2015.

Business Acquisitions

On May 1, 2014, BHE entered into a Share Purchase Agreement whereby BHE, through a subsidiary, will acquire 100% of AltaLink, an indirect wholly-owned subsidiary of SNC-Lavalin Group Inc. ("SNC-Lavalin"), for an estimated cash purchase price of C\$3.2 billion (approximately US\$2.9 billion as of September 30, 2014). The purchase price is subject to adjustments based on certain capital contributions made into AltaLink and an interest component that will change based on the timing of closing. BHE's shareholders have committed to provide the capital to fund the entire purchase price of AltaLink; however, BHE expects to fund the purchase price with capital from Berkshire Hathaway and by issuing senior unsecured debt at BHE. AltaLink is a regulated transmission-only business, headquartered in Calgary, Alberta. The transaction has been approved by both the SNC-Lavalin and BHE boards of directors. In June 2014, an Advance Ruling Certificate was received from the Commissioner of Competition, providing clearance for the AltaLink acquisition. On July 25, 2014, the Canadian Minister of Industry approved the transaction under the Investment Canada Act, determining that the AltaLink transaction constitutes a net benefit to Canada. The Share Purchase Agreement contains customary representations, warranties and covenants of both SNC-Lavalin and BHE, and is subject to customary closing conditions, including one remaining governmental approval by the Alberta Utilities Commission. The transaction is expected to be completed by the end of 2014.

Energy Imbalance Market

PacifiCorp and the California Independent System Operator Corporation ("California ISO") implemented a new energy imbalance market ("EIM") in October 2014 beginning with a 30-day transition period where the California ISO and PacifiCorp enabled their systems to interact and produce results reflecting realistic market conditions, but without financially binding settlements or dispatch instructions. The EIM transitioned to a fully operational, financially binding market on November 1, 2014. The EIM is expected to reduce costs to serve customers through more efficient dispatch of a larger and more diverse pool of resources, more effectively integrate renewables and enhance reliability through improved situational awareness and responsiveness. In today's environment, utilities in the west outside the California ISO rely upon a combination of automated and manual dispatch within the hour to balance generation and load to maintain reliable supply and have limited capability to transact within the hour outside their own borders. In contrast, the EIM will optimize and automate five-minute dispatch of generation to serve load across the entire six-state PacifiCorp and California ISO footprint. The EIM is voluntary and available to all balancing authorities in the Western United States. Benefits to customers are expected to increase as more entities join and the footprint grows, bringing incremental generation and load diversity. In June 2014, the FERC issued two orders on tariff revisions to implement the EIM proposed by PacifiCorp and the California ISO, respectively, subject to compliance filings. In October 2014, the FERC issued orders accepting PacifiCorp's and the California ISO's compliance filings, subject to an additional compliance filing by each entity no later than November 19, 2014.

NV Energy has announced plans to join the EIM in October 2015 subject to regulatory approvals. In April 2014, NV Energy filed an application to amend its portfolio optimization procedures contained in the PUCN-approved energy supply plan for the remaining action period of 2016. The PUCN's final order approving the merger between BHE and NV Energy stipulated that NV Energy would obtain PUCN authorization prior to participating in an EIM. The amendment reflects NV Energy's participation in the EIM. The filing requested the PUCN to determine that the amended energy supply plan balances the objectives of minimizing the cost of supply and retail price volatility, maximizes the reliability of supply over the remaining term of the plan, optimizes the value of the overall supply portfolio of NV Energy for the benefit of bundled retail customers and does not contain any features or mechanisms that the PUCN finds would impair the restoration or the creditworthiness of NV Energy. The PUCN issued an order in August 2014 finding that it is in the public interest to grant the application and that NV Energy met the merger stipulation requirement to obtain PUCN approval prior to participating in an EIM. In April 2014, the California ISO filed the Implementation Agreement entered into by NV Energy and the California ISO. The Implementation Agreement provides the mechanism by which NV Energy will compensate the California ISO for its share of the costs to upgrade systems, software licenses and other configuration activities. The Implementation Agreement was approved by the FERC in June 2014.

Contractual Obligations

As of September 30, 2014, there have been no material changes outside the normal course of business in contractual obligations from the information provided in Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2013 other than the 2014 debt issuances previously discussed.

In October 2014, MidAmerican Energy entered into a contract with Siemens Energy Inc. ("Siemens") for the servicing, maintenance and repair of a majority of MidAmerican Energy's wind turbines procured from Siemens, including turbines currently under construction and turbines currently under warranty once the coverage expires. MidAmerican Energy expects to have more than 950 Siemens wind turbines in service by the end of 2015 that will be covered by the contract through June 2024.

Regulatory Matters

BHE's regulated subsidiaries and certain affiliates are subject to comprehensive regulation. The discussion below contains material developments to those matters disclosed in Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2013, and new regulatory matters occurring in 2014.

PacifiCorp

Utah

In January 2014, PacifiCorp filed a general rate case with the UPSC requesting an annual increase of $76 million, or an average price increase of 4%. PacifiCorp filed subsequent rebuttal testimony reducing the requested increase to $66 million. The requested increase includes recovery of PacifiCorp's investment in Lake Side 2, which was placed in-service in May 2014, and the Mona-Oquirrh transmission line investment found to be prudent in the prior general rate case. In August 2014, the UPSC approved a multi-party stipulation that provides for a two-step rate increase. The first increase of $35 million, or an average price increase of 2%, was effective September 2014, and the second increase of $19 million, or an average price increase of 1%, will be effective the later of September 2015 or the in-service date of the Sigurd-Red Butte transmission line. The stipulation resolved most issues in the general rate case, but did not settle the net metering facilities charge proposed by PacifiCorp, which was moved by the UPSC to a new docket for further analysis. The stipulation also specifies that September 2016 would be the earliest effective date that PacifiCorp could seek an increase to customers' rates in Utah, with the exception of the year-two increase agreed to above and other UPSC-approved and currently existing rate adjustment mechanisms, including the Energy Balancing Account ("EBA") pilot for which the stipulation provides a one-year extension through 2016.

In March 2014, PacifiCorp filed its annual EBA with the UPSC requesting $28 million, or an increase of 2%, for recovery of deferred net power costs for the period January 1, 2013 through December 31, 2013. In October 2014, the UPSC approved an all-party stipulation providing for a rate increase of $25 million, or 1%, effective November 2014. The parties to the stipulation agreed that, effective November 2014, the $25 million would be combined with the remaining deferral balances currently being collected in the EBA of $19 million, with the total balance of $44 million to be collected over a 12-month period beginning November 2014.

In March 2014, PacifiCorp filed its annual renewable energy credit balancing account application with the UPSC requesting recovery of $17 million over a three-year period. In May 2014, the UPSC approved interim rates effective June 2014. In September 2014, the UPSC issued a final order approving the interim rates as final.

Oregon

In April 2014, PacifiCorp made its initial filing for the annual Transition Adjustment Mechanism with the OPUC for an annual increase of $18 million, or an average price increase of 2%, based on forecasted net power costs for calendar year 2015. In July 2014, PacifiCorp filed an all-party stipulation with the OPUC resolving all issues in the proceeding. The stipulation reflects an overall annual increase of $10 million, or an average price increase of 1%, subject to updates through November 2014. In October 2014, the OPUC issued an order approving the stipulation. The new rates will be effective January 2015.

In April 2014, PacifiCorp filed for a separate tariff rider with the OPUC to recover the Oregon-allocated costs of PacifiCorp's investment in Lake Side 2. The separate tariff rider was agreed to in the 2013 Oregon general rate case stipulation with final costs subject to a prudence determination. The filing supports an overall rate increase of $22 million, or an average price increase of 2%. In May 2014, the OPUC approved the new rates effective June 2014.

Wyoming

In March 2014, PacifiCorp filed a general rate case with the WPSC requesting an annual increase of $36 million, or an average price increase of 5%. In September 2014, PacifiCorp filed rebuttal testimony reducing the requested increase to $32 million, or an average price increase of 5%. The requested increase includes recovery of PacifiCorp's investments in Lake Side 2 and the Mona-Oquirrh transmission line. Hearings were held by the WPSC in October 2014. If approved by the WPSC, the new rates will be effective January 2015.

In March 2014, PacifiCorp filed its annual Energy Cost Adjustment Mechanism ("ECAM") and Renewable Energy Credit and Sulfur Dioxide Revenue Adjustment Mechanism ("RRA") applications with the WPSC. The ECAM filing requests recovery of $17 million of deferred net power costs for the period January 1, 2013 through December 31, 2013, and the RRA application requests a $4 million increase in the RRA surcharge. The two applications represent a combined total price increase of 3%. In May 2014, the WPSC approved the ECAM and RRA rates effective May 2014 on an interim basis subject to further investigation and hearing.

Washington

In December 2012, PacifiCorp submitted a compliance filing with the WUTC presenting Washington-allocated actual renewable energy credit sales revenues of $17 million from January 1, 2009 through April 2, 2011. Also in December 2012, PacifiCorp filed for judicial review of the WUTC's August 2012 order requiring PacifiCorp to credit to its retail customers all proceeds from the sale of renewable energy credits attributable to Washington that were recorded on or after January 1, 2009, less any amounts already credited to retail customers, and the WUTC's November 2012 order denying PacifiCorp's petition for reconsideration and stay of the August 2012 order. In February 2013, PacifiCorp, WUTC staff and intervening parties submitted a joint filing with the WUTC proposing a tracking mechanism for renewable energy credit sales revenues from April 3, 2011 forward. In March 2013, the WUTC issued a notice stating that the February 2013 joint filing failed to comply with the WUTC's orders, primarily requiring PacifiCorp and other parties to clarify the period over which amortization of historical renewable energy credit sales revenues (revenues from January 1, 2009 through April 2, 2011) would occur. In March 2013, PacifiCorp filed a response to the WUTC notice requesting that the WUTC not require amortization of historical renewable energy credit sales revenues until after resolution of the pending judicial review of the WUTC's orders. In June 2014, a multi-party stipulation was filed with the WUTC resolving the request for judicial review associated with the appropriate rate treatment of renewable energy credit sales revenues from January 1, 2009 through April 2, 2011. The terms of the settlement include a one-time credit to customers totaling $13 million for renewable energy credit sales revenues from January 1, 2009 through April 2, 2011. The WUTC approved the stipulation and the one-time credit to customers effective June 2014. In July 2014, the Washington State Court of Appeals granted the parties' joint motion to dismiss the petition for judicial review.

In May 2014, PacifiCorp filed a general rate case with the WUTC requesting an annual increase of $27 million, or an average price increase of 8%. If approved by the WUTC, the new rates will be effective March 2015.

In October 2014, PacifiCorp filed for a temporary rate increase of $5 million, or an average price increase of 2%, to recover the amount of renewable energy credits reflected in customers' rates in excess of actual renewable energy credits sold from April 3, 2011 through December 31, 2013. PacifiCorp's proposal is consistent with the joint filing for a renewable energy credit tracking mechanism filed with the WUTC in February 2013. If approved by the WUTC, the new rates will be effective November 2014 and will remain in effect for approximately one year.

Idaho

In January 2014, PacifiCorp filed its annual ECAM application with the IPUC requesting recovery of $13 million of deferred net power costs. In April 2014, the IPUC issued an order approving recovery of $12 million of deferred net power costs, of which $7 million will be collected over a 12-month period and the remainder collected over a 24-month period, with new rates effective April 2014.

MidAmerican Energy

In March 2014, the IUB issued an order approving, with modifications, a non-unanimous settlement agreement among MidAmerican Energy, the Iowa Office of Consumer Advocate and environmental parties. The IUB order allows MidAmerican Energy to increase its base rates over approximately three years and will result in equal annualized increases in revenues of $45 million, or 3.6% over 2012, effective August 2013 and again on January 1, 2015 and 2016, for a total annualized increase of $135 million when fully implemented. In addition to an increase in base rates, the order approves the implementation of two adjustment clauses. One clause relates to retail energy production costs such as fuel, fuel transportation and the impacts of the production tax credit. The second clause relates to certain electric transmission charges. The adjustment clauses provide for recovery of these costs from customers based on MidAmerican Energy's forecasted annual costs, with the variance between actual and forecasted costs to be recovered or credited in the following year. The order also equalizes rates among MidAmerican Energy's current three pricing zones over a ten-year period. Rate equalization adjustments are revenue-neutral for MidAmerican Energy. The parties to the settlement agreement also agree not to seek or support an increase or decrease in the final base rates to become effective prior to January 1, 2018, unless MidAmerican Energy projects its return on equity for 2015, 2016 or 2017 to be below 10%. The IUB order also approves a revenue sharing mechanism that shares with MidAmerican Energy's customers 80% of revenues related to equity returns above 11% and 100% of revenues related to equity returns above 14%. The customer portion of any sharing reduces rate base. In April 2014, a number of the industrial intervenors sought rehearing on certain issues in the IUB order. The IUB granted rehearing for the purpose of reconsideration and on July 10, 2014, issued an order on rehearing that affirmed all of the economic provisions of its March 2014 order. On July 31, 2014, the IUB issued an order authorizing MidAmerican Energy to implement the new base rates and adjustment clauses effective immediately.

In December 2013, MidAmerican Energy filed a request with the Illinois Commerce Commission ("ICC") for a $22 million, or 17%, annual increase in Illinois retail electric base rates. In addition to the increase in base rates, the filing contains a request for the creation of a new adjustment clause for recovery of certain electric transmission charges to be effective with the implementation of final approved rates. On November 7, 2014, the ICC issued an order approving a retail electric base rate increase for MidAmerican Energy's Illinois customers. The order authorizes MidAmerican Energy to increase rates by $16 million, or 10%, annually and to implement the new adjustment clause for the recovery of electric transmission charges. New rates and the adjustment clause are expected to go into effect by December 1, 2014.

NV Energy

The PUCN's final order approving the merger between BHE and NV Energy stipulated that NV Energy will not seek recovery of any lost revenue for calendar year 2014 in an amount that exceeds 50% of the lost revenue that NV Energy could otherwise request. In February 2014, NV Energy filed an application with the PUCN to reset the energy efficiency implementation rate. In June 2014, the PUCN accepted a stipulation to adjust the energy efficiency implementation rate, as of July 1, 2014, to collect 50% of the estimated lost revenue that NV Energy would otherwise be allowed to recover for the 2014 calendar year. The energy efficiency implementation rate will be effective from July through December 2014 and will reset on January 1, 2015 and remain in effect through September 2015. To the extent NV Energy's earned rate of return exceeds the rate of return used to set base general rates, NV Energy is required to refund to customers energy efficiency implementation rate revenue collected. As a result, NV Energy has deferred recognition of energy efficiency implementation rate revenue collected and has recorded a liability of $13 million on the Consolidated Balance Sheets as of September 30, 2014.

In May 2014, Nevada Power filed its Emission Reduction Capacity Replacement Plan ("ERCR Plan") in compliance with Senate Bill No. 123 ("SB 123") enacted by the 2013 Nevada Legislature. The filing proposed, among other items, the retirement of Reid Gardner Generating Station units 1, 2 and 3 in 2014 and unit 4 in 2017; the elimination of Nevada Power's ownership interest in Navajo Generating Station in 2019; and a plan to replace the generating capacity being retired, as required by SB 123. The ERCR Plan includes the issuance of requests for proposals for 300 MW of renewable energy to be issued between 2014 and 2016; the acquisition of a 274-MW natural gas co-generating facility in 2014; the acquisition of a 222-MW natural gas peaking facility in 2014; the construction of a 15-MW solar photovoltaic facility expected to be placed in-service in 2015; and the construction of a 200-MW solar photovoltaic facility expected to be placed in-service in 2016. In the second quarter of 2014, Nevada Power executed various contractual agreements to fulfill the proposed ERCR Plan, which are subject to PUCN approval. The impacts of the ERCR Plan to Nevada Power's 2014 forecasted capital expenditures are included in the Future Uses of Cash previously discussed. The PUCN issued an order dated October 28, 2014 removing the 200-MW solar photovoltaic facility proposed by Nevada Power from the ERCR Plan but accepting the remaining requests. Under Nevada law, Nevada Power may elect to accept the plan as modified by the PUCN, file a motion for reconsideration or withdraw the filing from consideration and file a new ERCR Plan. In November 2014, Nevada Power filed a request to extend the deadline to make its election. The Company cannot determine the outcome of this proceeding at this time.

In May 2014, Nevada Power filed a general rate case with the PUCN. In July 2014, Nevada Power made its certification filing, which requested incremental annual revenue relief in the amount of $38 million, or an average price increase of 2%. In October 2014, Nevada Power reached a settlement agreement with certain parties agreeing to a zero increase in the revenue requirement. In October 2014, the PUCN approved and issued an order in the general rate case filing that agreed to the settlement. The order provides for increases in the fixed-monthly service charge for customers with a corresponding decrease in the base tariff general rate effective January 1, 2015. In October 2014, a party filed a petition for reconsideration of the PUCN order. Nevada Power is preparing a response to the reconsideration.

In connection with Nevada Power's general rate case filing in May 2014, as required by the PUCN, Sierra Pacific made a "companion filing" for the purpose of documenting the costs and benefits of Sierra Pacific's investment in the advanced service delivery program. In October 2014, the PUCN issued an order in the companion filing issued with the general rate case order that, among other things, provided for the implementation of new rates effective January 1, 2015 to begin recovery of costs associated with advance service delivery. The recovery costs will increase annual revenue approximately $10 million.

Kern River

In December 2009, the FERC issued an order establishing revised rates for the period of Kern River's initial long-term contracts ("Period One rates") and required that rates be established based on a levelized rate design for eligible customers that elect to take service following the expiration of their initial contracts ("Period Two rates"). In November 2010, the FERC issued an order that established Kern River is entitled to base its Period Two rates on a 100% equity capital structure.

In July 2011, the FERC issued an order requiring, among other things, that Period Two rates be based on a return on equity of 11.55% and a levelization period that coincides with a contract length of 10 or 15 years. Kern River filed in compliance with the FERC's order in August 2011 and, following an order on compliance, again in September 2011. In late September 2011, the FERC issued a second order on compliance, accepting Kern River's filing. In February 2013, the FERC issued an order that denied the requests for rehearing regarding its previous orders on Period Two rates.

In December 2013, Kern River filed its notice of appeal with the United States Court of Appeals for the District of Columbia. Kern River appealed the effective date of the final order for purposes of refunds and the denial of allowing a modification to Period One rates related to the rolled in shipper group rate credit. The shipper group has appealed the appropriate rate of return to be utilized in designing Period Two rates in conjunction with the use of a 100% equity capital structure. The court has established a briefing schedule and oral argument is expected to be in the second quarter of 2015.

Environmental Laws and Regulations

The Company is subject to federal, state, local and foreign laws and regulations regarding air and water quality, renewable portfolio standards, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact the Company's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by the EPA and various state, local and international agencies. The Company believes it is in material compliance with all applicable laws and regulations, although many are subject to interpretation that may ultimately be resolved by the courts. Refer to "Liquidity and Capital Resources" for discussion of the Company's forecasted environmental-related capital expenditures. The discussion below contains material developments to those matters disclosed in Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2013.

Clean Air Act Regulations

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

Mercury and Air Toxics Standards

The Clean Air Mercury Rule ("CAMR"), issued by the EPA in March 2005, was the United States' first attempt to regulate mercury emissions from coal-fueled generating facilities through the use of a market-based cap-and-trade system. The CAMR, which mandated emissions reductions of approximately 70% by 2018, was overturned by the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") in February 2008. In March 2011, the EPA proposed a new rule that would require coal-fueled generating facilities to reduce mercury emissions and other hazardous air pollutants through the establishment of "Maximum Achievable Control Technology" standards rather than a cap-and-trade system. The final rule, Mercury and Air Toxics Standards ("MATS"), was published in the Federal Register in February 2012, with an effective date of April 16, 2012, and requires that new and existing coal-fueled generating facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. Existing sources are required to comply with the new standards by April 16, 2015. Individual sources may be granted up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls or for transmission system reliability reasons. The Company believes that its emissions reduction projects completed to date or currently permitted or planned for installation, including scrubbers, baghouses and electrostatic precipitators, are consistent with the EPA's MATS and will support the Company's ability to comply with the final rule's standards for acid gases and non-mercury metallic hazardous air pollutants. The Company will be required to take additional actions to reduce mercury emissions through the installation of controls or use of sorbent injection at certain of its coal-fueled generating facilities and otherwise comply with the final rule's standards, which may include retiring certain units.

PacifiCorp continues to plan for retirement of the Carbon coal-fueled generating facility ("Carbon Facility") in early 2015 as the least-cost alternative to comply with the MATS and other environmental regulations. Efforts are underway to effectuate the decommissioning activities and transmission system modifications necessary to maintain system reliability following disconnection. The Carbon Facility produced 1.2 million megawatt hours ("MWh") of electricity, or 2.1% of PacifiCorp's owned generation production, during 2013.

MidAmerican Energy plans to retire four coal-fueled generating units between 2015 and 2016 as the least-cost alternative to comply with the MATS. These units are Walter Scott, Jr. Energy Center Units 1 and 2, and George Neal Energy Center Units 1 and 2. These units produced 2.0 million MWh of electricity, or 7% of MidAmerican Energy's owned generation production, during 2013. A fifth unit, Riverside Generating Station, will be limited to natural gas combustion by March 31, 2015.

Incremental costs to install and maintain emissions control equipment at the Company's coal-fueled generating facilities and any requirement to shut down what have traditionally been low cost coal-fueled generating facilities will likely increase the cost of providing service to customers. In addition, numerous lawsuits were filed against the MATS in the D.C. Circuit. In April 2014, the D.C. Circuit upheld the MATS requirements.

Clean Air Interstate Rule, Clean Air Transport Rule and Cross-State Air Pollution Rule

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

In July 2008, a three-judge panel of the D.C. Circuit issued a unanimous decision vacating the CAIR. In December 2008, the D.C. Circuit issued an opinion remanding, without vacating, the CAIR back to the EPA to conduct proceedings to fix the flaws in CAIR consistent with the D.C. Circuit's July 2008 ruling. In response to the court's ruling on CAIR, in July 2010, the EPA proposed the Clean Air Transport Rule ("Transport Rule"), which required electric generating units in 31 states and the District of Columbia to reduce emissions of nitrogen oxides and sulfur dioxide on a state-by-state basis in accordance with each state's modeled contribution to nonattainment of the ozone and fine particulate standards in downwind states.

In July 2011, the EPA issued the final Transport Rule, renamed the Cross-State Air Pollution Rule ("CSAPR"), to address interstate transport of sulfur dioxide and nitrogen oxides emissions in 27 eastern and Midwestern states. Upon full implementation in 2014, the CSAPR would have reduced total sulfur dioxide emissions by 73% and nitrogen oxides emissions by 54% at electric generating facilities in the 27-state region as compared to 2005 levels.

In December 2011, the D.C. Circuit issued a stay on the implementation of the CSAPR pending consideration of several petitions for review before the court which were ultimately decided in August 2012, when the D.C. Circuit vacated the CSAPR in a 2-1 decision after it determined that the CSAPR exceeded the EPA's statutory authority. In a petition filed in October 2012, the EPA sought a full review of the CSAPR ruling by the entire D.C. Circuit. In January 2013, the D.C. Circuit denied the request. The case was appealed to the United States Supreme Court where oral arguments were heard in December 2013. The United States Supreme Court issued its decision April 29, 2014, upholding the 2011 CSAPR and reversing the D.C. Circuit's ruling, concluding that the EPA's allocation of emissions reductions in upwind states permissibly considered the cost-effectiveness of achieving downwind attainment and that the EPA has authority under the Clean Air Act to impose federal implementation plans immediately after disapproving state implementation plans. The United States Supreme Court remanded the case to the D.C. Circuit for further action. The D.C. Circuit's previous stay of the rule was lifted in October 2014 and the first phase of the rule may be implemented as early as January 2015.

MidAmerican Energy has installed emissions controls at some of its coal-fueled generating facilities to comply with the CSAPR and may purchase emissions allowances to meet a portion of its compliance obligations. The cost of these allowances is subject to market conditions at the time of purchase and historically has not been material. The full impact of the CSAPR cannot be determined until the rule is fully implemented. However, MidAmerican Energy believes that the controls installed to date are consistent with the reductions to be achieved from implementation of such a rule.

MidAmerican Energy operates natural gas-fueled generating facilities in Iowa and MidAmerican Renewables operates natural gas-fueled generating facilities in Texas, Illinois and New York, which are subject to the CSAPR. However, the provisions are not anticipated to have a material impact on the Company. None of PacifiCorp's, Nevada Power's or Sierra Pacific's generating facilities are subject to the CSAPR.

Regional Haze

The EPA has initiated a regional haze program intended to improve visibility in designated federally protected areas ("Class I areas"). Some of PacifiCorp's coal-fueled generating facilities in Utah, Wyoming and Arizona and certain of Nevada Power's and Sierra Pacific's fossil-fueled generating facilities are subject to the Clean Air Visibility Rules. In accordance with the federal requirements, states are required to submit SIPs that address emissions from sources subject to best available retrofit technology ("BART") requirements and demonstrate progress towards achieving natural visibility requirements in Class I areas by 2064.

The state of Utah issued a regional haze SIP requiring the installation of sulfur dioxide, nitrogen oxides and particulate matter controls on Hunter Units 1 and 2, and Huntington Units 1 and 2. In December 2012, the EPA approved the sulfur dioxide portion of the Utah regional haze SIP and disapproved the nitrogen oxides and particulate matter portions. Certain groups appealed the EPA's approval of the sulfur dioxide portion and oral argument was heard before the United States Court of Appeals for the Tenth Circuit ("Tenth Circuit") in March 2014. In October 2014, the Tenth Circuit upheld the EPA's approval of the sulfur dioxide portion of the SIP. The state of Utah and PacifiCorp filed petitions for administrative and judicial review of the EPA's final rule on the BART determinations for nitrogen oxides and particulate matter portions of Utah's regional haze SIP in March 2013. Oral argument was held before the Tenth Circuit in March 2014. In May 2014, the Tenth Circuit dismissed the petition, concluding that even though the EPA had changed the promulgation date for its final action, the EPA did not do so explicitly, the filing date for petitions for judicial review ran from the EPA's original action, and the Tenth Circuit had no jurisdiction to decide the case. The state of Utah and PacifiCorp then filed petitions for review of the Tenth Circuit's dismissal, which the Tenth Circuit again rejected in September 2014. In addition, and separate from the EPA's approval process and related litigation, the Utah Division of Air Quality has undertaken an additional BART analysis for Hunter Units 1 and 2, and Huntington Units 1 and 2, which will be provided to the EPA as a supplement to the existing Utah SIP after the public comment period closes December 1, 2014, and the Utah Division of Air Quality responds to the public comments. It is unknown whether and how this supplemental analysis will impact the EPA's decision regarding the Utah SIP.

The state of Wyoming issued two regional haze SIPs requiring the installation of sulfur dioxide, nitrogen oxides and particulate matter controls on certain PacifiCorp coal-fueled generating facilities in Wyoming. The EPA approved the sulfur dioxide SIP in December 2012. Certain groups have appealed the EPA's approval of the sulfur dioxide SIP, and PacifiCorp has intervened in that appeal. Oral argument was held before the Tenth Circuit in March 2014. In October 2014, the Tenth Circuit upheld the EPA's approval of the sulfur dioxide portion of the SIP. In addition, the EPA initially proposed in June 2012 to disapprove portions of the nitrogen oxides and particulate matter SIP and instead issue a federal implementation plan ("FIP"). The EPA withdrew its initial proposed actions on the nitrogen oxides and particulate matter SIP and the proposed FIP, published a re-proposed rule in June 2013, and finalized its determination on January 10, 2014, which aligns more closely with the SIP proposed by the state of Wyoming. The EPA's final action on the Wyoming SIP approved the state's plan to have PacifiCorp install low-nitrogen oxides burners at Naughton Units 1 and 2, selective catalytic reduction at Naughton Unit 3 by December 2014, selective catalytic reduction at Jim Bridger Units 1 through 4 between 2015 and 2022, and low-nitrogen oxides burners at Dave Johnston Unit 4. The EPA disapproved the Wyoming SIP and issued a FIP for Dave Johnston Unit 3, where it required the installation of selective catalytic reduction by 2019 or, in lieu of installing selective catalytic reduction, a commitment to shut down Dave Johnston Unit 3 by 2027, its currently approved depreciable life. The EPA also disapproved the Wyoming SIP and issued a FIP for the Wyodak coal-fueled generating facility ("Wyodak Facility"), requiring the installation of selective catalytic reduction within five years (i.e., by 2019). The EPA action became final on March 3, 2014. PacifiCorp filed an appeal of the EPA's final action on the Wyodak Facility in March 2014. The state of Wyoming has also filed an appeal of the EPA's final action, as have the Powder River Basin Resource Council, National Parks Conservation Association and Sierra Club. In September 2014, the Tenth Circuit issued a stay of the March 2019 compliance deadline for the Wyodak Facility, pending further action by the Tenth Circuit in the appeal. With respect to Naughton Unit 3, the EPA indicated it supported the conversion of the unit to natural gas and would expedite action relative to consideration of the natural gas conversion once the state of Wyoming submitted the requisite SIP amendment; nonetheless, the Naughton Unit 3 natural gas conversion remains subject to final approval by the EPA. In June 2014, the Wyoming Department of Environmental Quality issued a revised BART permit providing for the Naughton Unit 3 natural gas conversion in 2018 and allowing the unit to operate on coal through 2017.

Environmental groups have challenged both of the EPA's final determinations with respect to Nevada's regional haze SIP. In May 2012, WildEarth Guardians petitioned the United States Court of Appeals for the Ninth Circuit ("Ninth Circuit") to review the EPA's March 2012 approval of Nevada's SIP for all affected units and emissions except nitrogen oxides controls at the Reid Gardner Generating Station. Both Nevada Power and Sierra Pacific intervened in the lawsuit and briefing was completed in February 2013. The matter was heard before the Ninth Circuit in May 2014. On July 17, 2014, the Ninth Circuit issued its decision, dismissing the petition in part because WildEarth Guardians did not have standing to challenge a portion of the SIP, and denying the petition in part based on its conclusion that the EPA's approval of the Nevada SIP was appropriate.

The Navajo Generating Station, in which Nevada Power is a joint owner with an 11.3% ownership share, is also a source that is subject to the regional haze BART requirements. In January 2013, the EPA announced a proposed FIP addressing BART and an alternative for the Navajo Generating Station that includes a flexible timeline for reducing nitrogen oxides emissions. Nevada Power, along with the other owners of the facility, have been reviewing the EPA's proposal to determine its impact on the viability of the facility's future operations. The land lease for the Navajo Generating Station is subject to renewal in 2019. Renewal of the lease will require completion of an Environmental Impact Statement as well as a renewal of the fuel supply agreement. In September 2013, the EPA issued a supplemental proposal that included another BART alternative called the Technical Work Group Alternative, which is based on a proposal submitted to the EPA by a group of Navajo Generating Station stakeholders. The EPA accepted comments on the various alternatives through January 6, 2014 and, in July 2014, the EPA announced it had approved the final plan for the Navajo Generating Station, including the reduction of emissions of nitrogen oxides by approximately 80% through the retirement of one unit in 2019 and installation of selective catalytic reduction controls at the other two units by 2030. In October 2014, several groups filed an appeal of the EPA's decision in the Ninth Circuit. Until such time as additional action is taken by the Ninth Circuit and the uncertainties regarding lease and agreement renewal terms for the Navajo Generating Station are addressed, the Company cannot predict the outcome of this matter. Nevada Power filed the ERCR Plan in May 2014 that proposed to eliminate its ownership participation in the Navajo Generating Station in 2019; the PUCN has issued an order and management is assessing its impacts.

A case was filed in the Tenth Circuit appealing a FIP issued by the EPA in New Mexico. In addition, two cases involving the EPA's issuance of a FIP were appealed to the United States Supreme Court in 2014, one from the Tenth Circuit based on the EPA rejecting portions of the Oklahoma SIP and one from the United States Court of Appeals for the Eighth Circuit based on the EPA's rejection of the North Dakota SIP. In May 2014, the United States Supreme Court issued its decisions denying review of the Oklahoma and North Dakota SIPs.

Until the EPA takes final action in each state and decisions have been made on each appeal, the Company cannot fully determine the impacts of the Regional Haze regulation on its generating facilities.

Climate Change

In June 2014, the EPA released proposed regulations to address greenhouse gas emissions from existing fossil-fueled generating facilities, referred to as the Clean Power Plan, under Section 111(d) of the Clean Air Act. The EPA's proposal calculated state-specific emission rate targets to be achieved based on four building blocks that it determined were the "Best System of Emission Reduction." The four building blocks include: (a) a 6% heat rate improvement from coal-fueled generating facilities; (b) increased utilization of existing combined-cycle natural gas-fueled generating facilities to 70%; (c) increased deployment of renewable and non-carbon generating resources; and (d) increased energy efficiency. Under the EPA's proposal, states may utilize any measure to achieve the specified emission reduction goals, with an initial implementation period of 2020-2029 and the final goal to be achieved by 2030. When fully implemented, the proposal is expected to reduce carbon dioxide emissions in the power sector to 30% below 2005 levels by 2030. The EPA is taking comment on its proposal until December 1, 2014 and is scheduled to issue final rules in June 2015. States are required to submit implementation plans by June 2016, but they may request an extension to June 2017, or June 2018 if they plan to participate in a regional compliance program. The impacts of the proposal on PacifiCorp, MidAmerican Energy, Nevada Power, Sierra Pacific and MidAmerican Renewables cannot be determined until the EPA finalizes the proposal and the states develop their implementation plans. PacifiCorp, MidAmerican Energy, Nevada Power and Sierra Pacific have historically pursued cost-effective projects, including plant efficiency improvements, increased diversification of their generating fleets to include deployment of renewable and lower carbon generating resources, and advancement of customer energy efficiency programs.

Water Quality Standards

The federal Water Pollution Control Act ("Clean Water Act") establishes the framework for maintaining and improving water quality in the United States through a program that regulates, among other things, discharges to and withdrawals from waterways. The Clean Water Act requires that cooling water intake structures reflect the "best technology available for minimizing adverse environmental impact" to aquatic organisms. In July 2004, the EPA established significant new technology-based performance standards for existing electricity generating facilities that take in more than 50 million gallons of water per day. These rules were aimed at minimizing the adverse environmental impacts of cooling water intake structures by reducing the number of aquatic organisms lost as a result of water withdrawals. In response to a legal challenge to the rule, in January 2007, the United States Court of Appeals for the Second Circuit ("Second Circuit") remanded almost all aspects of the rule to the EPA, without addressing whether companies with cooling water intake structures were required to comply with these requirements. On appeal from the Second Circuit, in April 2009, the United States Supreme Court ruled that the EPA permissibly relied on a cost-benefit analysis in setting the national performance standards regarding "best technology available for minimizing adverse environmental impact" at cooling water intake structures and in providing for cost-benefit variances from those standards as part of the §316(b) Clean Water Act Phase II regulations. The United States Supreme Court remanded the case back to the Second Circuit to conduct further proceedings consistent with its opinion.

In March 2011, the EPA released a proposed rule under §316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The proposed rule establishes requirements for all power generating facilities that withdraw more than two million gallons per day, based on total design intake capacity, of water from waters of the United States and use at least 25% of the withdrawn water exclusively for cooling purposes. PacifiCorp's Dave Johnston generating facility and all of MidAmerican Energy's coal-fueled generating facilities, except Louisa, Ottumwa and Walter Scott, Jr. Unit 4, which have water cooling towers, withdraw more than two million gallons per day of water from waters of the United States for once-through cooling applications. PacifiCorp's Jim Bridger, Naughton, Gadsby, Hunter, Carbon and Huntington generating facilities currently utilize closed cycle cooling towers but withdraw more than two million gallons of water per day. The proposed rule includes impingement (i.e., when fish and other organisms are trapped against screens when water is drawn into a facility's cooling system) mortality standards to be met through average impingement mortality or intake velocity design criteria and entrainment (i.e., when organisms are drawn into the facility) standards to be determined on a case-by-case basis. The standards are required to be met as soon as possible after the effective date of the final rule, but no later than eight years thereafter. While the rule was required to be finalized by the EPA by July 2012, the deadline for finalizing the rule was extended to June 2013 and then again to January 2014. The final rule was released May 19, 2014, and allows facilities to choose one of seven options to reduce fish impingement. Facilities that withdraw at least 125 million gallons of water per day must conduct studies to help their permitting authority determine what site-specific controls, if any, would be required to reduce entrainment of aquatic organisms. PacifiCorp and MidAmerican Energy are assessing the options for compliance at their generating facilities impacted by the final rule and will complete impingement and entrainment studies. The costs of compliance with the cooling water intake structure rule cannot be determined until the prescribed studies are conducted. In the event that PacifiCorp's or MidAmerican Energy's existing intake structures require modification, the costs are not anticipated to be significant to the consolidated financial statements. Nevada Power and Sierra Pacific do not utilize once-through cooling water intake or discharge structures at any of their generating facilities. All of the Nevada Power and Sierra Pacific generating stations are designed to have either minimal or zero discharge; therefore, they are not expected to be impacted by the §316(b) final rule.

In June 2013, the EPA published proposed effluent limitation guidelines and standards for the steam electric power generating sector. These guidelines, which had not been revised since 1982, were revised in response to the EPA's concerns that the addition of controls for air emissions have changed the effluent discharged from coal- and natural gas-fueled generating facilities. While the EPA expected the final rule to be published in May 2014, the final rule is now scheduled for release by September 30, 2015. It is likely that the new guidelines will impose more stringent limits on wastewater discharges from coal-fueled generating facilities and ash and scrubber ponds. However, until the revised guidelines are finalized, the Company cannot predict the impact on its generating facilities.

In April 2014, the EPA and the United States Army Corps of Engineers issued a joint proposal to address "Waters of the United States" to clarify protection under the Clean Water Act for streams and wetlands. The proposed rule comes as a result of United States Supreme Court decisions in 2001 and 2006 that created confusion regarding jurisdictional waters that were subject to permitting under either nationwide or individual permitting requirements. As currently proposed, a variety of projects that otherwise would have qualified for streamlined permitting processes under nationwide or regional general permits will be required to undergo more lengthy and costly individual permit procedures based on an extension of waters that will be deemed jurisdictional. The public comment period has been extended on the proposal to November 14, 2014. Until the rule is finalized, the Company cannot determine whether projects that include construction and demolition will face more complex permitting issues, higher costs or increased requirements for compensatory mitigation.

Collateral and Contingent Features

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

BHE and its subsidiaries have no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments. The Company's unsecured revolving credit facilities do not require the maintenance of a minimum credit rating level in order to draw upon their availability. However, commitment fees and interest rates under the credit facilities are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities.

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base certain collateral requirements on credit ratings for senior unsecured debt as reported by one or more of the three recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance," or in some cases terminate the contract, in the event of a material adverse change in creditworthiness. These rights can vary by contract and by counterparty. As of September 30, 2014, the applicable credit ratings from the three recognized credit rating agencies were investment grade. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of September 30, 2014, the Company would have been required to post $401 million of additional collateral. The Company's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors. Refer to Note 9 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q for a discussion of the Company's collateral requirements specific to the Company's derivative contracts.

In accordance with BHE's equity commitment agreement related to the Topaz and Solar Star Projects, if BHE does not maintain at least an investment grade credit rating from at least two of the three credit ratings agencies, BHE's obligations under the equity commitment agreement would be supported by cash collateral or a letter of credit issued by a financial institution that meets certain minimum criteria specified in the financing documents. Upon reaching the final commercial operation date of the Topaz and Solar Star Projects, BHE will have no further obligation to make any equity contribution and any unused equity contribution obligations will be canceled. As of September 30, 2014, the remaining equity commitment for the Topaz Project was $550 million and for the Solar Star Projects was $1.19 billion. Refer to Note 11 of Notes to Consolidated Financial Statements in this Form 10-Q for a discussion of the Company's collateral requirements specific to the Company's equity commitments.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting the Company, refer to Note 2 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q.

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Consolidated Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty and will likely change in the future as additional information becomes available. Estimates are used for, but not limited to, the accounting for the effects of certain types of regulation, derivatives, impairment of goodwill and long-lived assets, pension and other postretirement benefits, income taxes and revenue recognition - unbilled revenue. For additional discussion of the Company's critical accounting estimates, see Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2013. There have been no significant changes in the Company's assumptions regarding critical accounting estimates since December 31, 2013.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

For quantitative and qualitative disclosures about market risk affecting the Company, see Item 7A of the Company's Annual Report on Form 10-K for the year ended December 31, 2013. The Company's exposure to market risk and its management of such risk has not changed materially since December 31, 2013, except as discussed below. Refer to Note 9 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q for disclosure of the Company's derivative positions as of September 30, 2014.

On May 1, 2014, BHE entered into a Share Purchase Agreement whereby BHE, through a subsidiary, will acquire 100% of AltaLink, L.P. ("AltaLink"), an indirect wholly-owned subsidiary of SNC-Lavalin Group Inc. ("SNC-Lavalin"), for an estimated cash purchase price of C$3.2 billion (approximately US$2.9 billion as of September 30, 2014). As of September 30, 2014, a 10% weakening of the United States dollar against the Canadian dollar would result in an increase in the United States dollars required at closing of approximately US$290 million. Refer to Note 3 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q for additional discussion.

Item 4. Controls and Procedures

At the end of the period covered by this Quarterly Report on Form 10-Q, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) promulgated under the Securities and Exchange Act of 1934, as amended). Based upon that evaluation, the Company's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), concluded that the Company's disclosure controls and procedures were effective to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the United States Securities and Exchange Commission's rules and forms, and is accumulated and communicated to management, including the Company's Chief Executive Officer (principal executive officer) and Chief Financial Officer (principal financial officer), or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. There has been no change in the Company's internal control over financial reporting during the quarter ended September 30, 2014 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II

Item 1. Legal Proceedings

None.

Item 1A. Risk Factors

There has been no material change to the Company's risk factors from those disclosed in Item 1A of the Company's Annual Report on Form 10-K for the year ended December 31, 2013.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Not applicable.

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. Mine Safety Disclosures

Information regarding the Company's mine safety violations and other legal matters disclosed in accordance with Section 1503 (a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act is included in Exhibit 95 to this Form 10-Q.

Item 5. Other Information

Not applicable.

Item 6. Exhibits

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

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

BERKSHIRE HATHAWAY ENERGY COMPANY
(Registrant)

Date: November 7, 2014

/s/ Patrick J. Goodman
Patrick J. Goodman
Executive Vice President and Chief Financial Officer
(principal financial and accounting officer)

EXHIBIT INDEX

Exhibit No.	Description
2.1	Share Purchase Agreement, dated as of May 1, 2014, by and among Berkshire Hathaway Energy Company and SNC-Lavalin Group Inc. and certain of its subsidiaries (incorporated by reference to Exhibit 2.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2014).
3.1	Articles of Amendment to the Second Amended and Restated Articles of Incorporation of MidAmerican Energy Holdings Company effective April 30, 2014 (incorporated by reference to Exhibit 3.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2014).
4.1	Twenty-Seventh Supplemental Indenture, dated as of March 1, 2014, by and between PacifiCorp and The Bank of New York Mellon Trust Company, N.A., to PacifiCorp's Mortgage and Deed of Trust dated as of January 9, 1989 (incorporated by reference to Exhibit 4.1 to the PacifiCorp Current Report on Form 8-K dated March 13, 2014).
4.2	Amendment No. 1 to the First Supplemental Indenture, dated as of April 3, 2014, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to MidAmerican Energy Company's Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated April 3, 2014).
4.3	Second Supplemental Indenture, dated as of April 3, 2014, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to MidAmerican Energy Company's Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated April 3, 2014).
10.1	$1,400,000,000 Credit Agreement, dated as of June 27, 2014, among Berkshire Hathaway Energy Company, as borrower, the Initial Lenders, Union Bank, N.A., as administrative agent and swingline lender and the LC Issuing Banks (incorporated by reference to Exhibit 10.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated June 27, 2014).
10.2	$400,000,000 Amended and Restated Credit Agreement, dated as of June 27, 2014, among Nevada Power Company, as borrower, the Initial Lenders, Wells Fargo Bank, National Association, as administrative agent and swingline lender and the LC Issuing Banks (incorporated by reference to Exhibit 10.1 to the Nevada Power Company Current Report on Form 8-K dated June 27, 2014).
10.3	$250,000,000 Amended and Restated Credit Agreement, dated as of June 27, 2014, among Sierra Pacific Power Company, as borrower, the Initial Lenders, Wells Fargo Bank, National Association, as administrative agent and swingline lender and the LC Issuing Banks (incorporated by reference to Exhibit 10.1 to the Sierra Pacific Power Company Current Report on Form 8-K dated June 27, 2014).
15	Awareness Letter of Independent Registered Public Accounting Firm.
31.1	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	Mine Safety Disclosures Required by the Dodd-Frank Wall Street Reform and Consumer Protection Act.
101	The following financial information from Berkshire Hathaway Energy Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2014, is formatted in XBRL (eXtensible Business Reporting Language) and included herein: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Changes in Equity, (v) the Consolidated Statements of Cash Flows, and (vi) the Notes to Consolidated Financial Statements, tagged in summary and detail.

EXHIBIT 15

November 7, 2014

To the Board of Directors and Shareholders of
Berkshire Hathaway Energy Company
Des Moines, Iowa

We have reviewed, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the unaudited consolidated interim financial information of Berkshire Hathaway Energy Company and subsidiaries for the periods ended September 30, 2014 and 2013, as indicated in our report dated November 7, 2014; because we did not perform an audit, we expressed no opinion on that information.

We are aware that our report referred to above, which is included in your Quarterly Report on Form 10-Q for the quarter ended September 30, 2014, is incorporated by reference in Registration Statement No. 333-147957 on Form S-8.

We also are aware that the aforementioned report, pursuant to Rule 436(c) under the Securities Act of 1933, is not considered a part of the Registration Statement prepared or certified by an accountant or a report prepared or certified by an accountant within the meaning of Sections 7 and 11 of that Act.

/s/ Deloitte & Touche LLP

Des Moines, Iowa

EXHIBIT 31.1

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

I, Gregory E. Abel, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Berkshire Hathaway Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 7, 2014

/s/ Gregory E. Abel
Gregory E. Abel
Chairman, President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.2

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

I, Patrick J. Goodman, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Berkshire Hathaway Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 7, 2014

/s/ Patrick J. Goodman
Patrick J. Goodman
Executive Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 32.1

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

I, Gregory E. Abel, Chairman, President and Chief Executive Officer of Berkshire Hathaway Energy Company (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Quarterly Report on Form 10-Q of the Company for the quarterly period ended September 30, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: November 7, 2014

/s/ Gregory E. Abel
Gregory E. Abel
Chairman, President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.2

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

I, Patrick J. Goodman, Executive Vice President and Chief Financial Officer of Berkshire Hathaway Energy Company (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Quarterly Report on Form 10-Q of the Company for the quarterly period ended September 30, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: November 7, 2014

/s/ Patrick J. Goodman
Patrick J. Goodman
Executive Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 95

MINE SAFETY VIOLATIONS AND OTHER LEGAL MATTER DISCLOSURES PURSUANT TO SECTION 1503(a) OF THE DODD-FRANK WALL STREET REFORM AND CONSUMER PROTECTION ACT

PacifiCorp and its subsidiaries operate certain coal mines and coal processing facilities (collectively, the "mining facilities") that are regulated by the Federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the "Mine Safety Act"). MSHA inspects PacifiCorp's mining facilities on a regular basis. The total number of reportable Mine Safety Act citations, orders, assessments and legal actions for the three-month period ended September 30, 2014 are summarized in the table below and are subject to contest and appeal. The severity and assessment of penalties may be reduced or, in some cases, dismissed through the contest and appeal process. Amounts are reported regardless of whether PacifiCorp has challenged or appealed the matter. Coal reserves that are not yet mined and mines that are closed or idled are not included in the information below as no reportable events occurred at those locations during the three-month period ended September 30, 2014. There were no mining-related fatalities during the three-month period ended September 30, 2014. PacifiCorp has not received any notice of a pattern, or notice of the potential to have a pattern, of violations of mandatory health or safety standards that are of such nature as could have significantly and substantially contributed to the cause and effect of coal or other mine health or safety hazards under Section 104(e) of the Mine Safety Act during the three-month period ended September 30, 2014.

	Mine Safety Act						Legal Actions		
Mining Facilities	Section 104 Significant and Substantial Citations(1)	Section 104(b) Orders(2)	Section 104(d) Citations/ Orders(3)	Section 110(b)(2) Violations(4)	Section 107(a) Imminent Danger Orders(5)	Total Value of Proposed MSHA Assessments (in thousands)	Pending as of Last Day of Period(6)	Instituted During Period	Resolved During Period
Deer Creek	3	—	—	—	—	$ 5	3	1	3
Bridger (surface)	1	—	—	—	—	7	2	1	—
Bridger (underground)	24	—	—	—	—	75	11	4	6
Cottonwood Preparatory Plant	—	—	—	—	—	—	—	—	—
Wyodak Coal Crushing Facility	—	—	—	—	—	—	—	—	—

(1) Citations for alleged violations of mandatory health and safety standards that could significantly or substantially contribute to the cause and effect of a safety or health hazard under Section 104 of the Mine Safety Act.

(2) For alleged failure to totally abate the subject matter of a Mine Safety Act Section 104(a) citation within the period specified in the citation.

(3) For alleged unwarrantable failure (i.e., aggravated conduct constituting more than ordinary negligence) to comply with a mandatory health or safety standard.

(4) For alleged flagrant violations (i.e., reckless or repeated failure to make reasonable efforts to eliminate a known violation of a mandatory health or safety standard that substantially and proximately caused, or reasonably could have been expected to cause, death or serious bodily injury).

(5) For the existence of any condition or practice in a coal or other mine which could reasonably be expected to cause death or serious physical harm before such condition or practice can be abated.

(6) Amounts include 14 contests of proposed penalties under Subpart C, one contest of a citation under Subpart B and one labor-related complaint under Subpart E of the Federal Mine Safety and Health Review Commission's procedural rules. The pending legal actions are not exclusive to citations, notices, orders and penalties assessed by MSHA during the reporting period.