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, 2015

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, 2015, 77,391,144 shares of common stock were outstanding.

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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 Powergrid	Northern Powergrid Holdings Company
Northern Natural Gas	Northern Natural Gas Company
Kern River	Kern River Gas Transmission Company
AltaLink	BHE AltaLink Ltd.
ALP	AltaLink, L.P.
BHE U.S. Transmission	BHE U.S. Transmission, LLC
HomeServices	HomeServices of America, Inc. and its subsidiaries
BHE Pipeline Group	Consists of Northern Natural Gas and Kern River
BHE Transmission	Consists of AltaLink and BHE U.S. Transmission
BHE Renewables	Consists of BHE Renewables, LLC and CalEnergy Philippines
Utilities	PacifiCorp, MidAmerican Energy, Nevada Power and Sierra Pacific
Berkshire Hathaway	Berkshire Hathaway Inc. and its subsidiaries
Topaz	Topaz Solar Farms LLC
Topaz Project	550-megawatt solar project in California
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 586-megawatt solar project in California

Certain Industry Terms	
AESO	Alberta Electric System Operator
AFUDC	Allowance for Funds Used During Construction
AUC	Alberta Utilities Commission
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gases
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;
- performance, availability and ongoing operation of the Company's facilities, including facilities not operated by the Company, due to the impacts of market conditions, outages and repairs, transmission constraints, weather, including wind, solar and hydroelectric conditions, and operating conditions;
- 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;
- 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 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, 2015, and the related consolidated statements of operations and comprehensive income for the three-month and nine-month periods ended September 30, 2015 and 2014, and of changes in equity and cash flows for the nine-month periods ended September 30, 2015 and 2014. 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, 2014, 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 February 27, 2015, 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, 2014 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 6, 2015

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

	As of	
	September 30, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,651	$ 617
Trade receivables, net	2,005	1,837
Income taxes receivable	115	1,156
Inventories	859	826
Mortgage loans held for sale	380	286
Other current assets	1,059	1,221
Total current assets	6,069	5,943
Property, plant and equipment, net	60,131	59,248
Goodwill	9,143	9,343
Regulatory assets	4,092	4,000
Investments and restricted cash and investments	3,126	2,803
Other assets	1,198	967
Total assets	$ 83,759	$ 82,304

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, 2015	December 31, 2014
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 1,657	$ 1,991
Accrued interest	474	454
Accrued property, income and other taxes	919	366
Accrued employee expenses	368	255
Short-term debt	940	1,445
Current portion of long-term debt	1,574	1,232
Other current liabilities	1,271	1,369
Total current liabilities	7,203	7,112
Regulatory liabilities	2,682	2,669
BHE senior debt	7,860	7,860
BHE junior subordinated debentures	3,194	3,794
Subsidiary debt	25,617	25,763
Deferred income taxes	12,234	11,802
Other long-term liabilities	2,781	2,731
Total liabilities	61,571	61,731
Commitments and contingencies (Note 13)		
Equity:		
BHE shareholders' equity:		
Common stock - 115 shares authorized, no par value, 77 shares issued and outstanding	—	—
Additional paid-in capital	6,412	6,423
Retained earnings	16,437	14,513
Accumulated other comprehensive loss, net	(797)	(494)
Total BHE shareholders' equity	22,052	20,442
Noncontrolling interests	136	131
Total equity	22,188	20,573
Total liabilities and equity	$ 83,759	$ 82,304

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,	
	2015	2014	2015	2014
Operating revenue:				
Energy	$ 4,324	$ 4,130	$ 11,787	$ 11,507
Real estate	745	644	1,951	1,619
Total operating revenue	5,069	4,774	13,738	13,126
Operating costs and expenses:				
Energy:				
Cost of sales	1,354	1,410	3,937	4,328
Operating expense	903	888	2,744	2,567
Depreciation and amortization	609	519	1,794	1,488
Real estate	667	582	1,790	1,518
Total operating costs and expenses	3,533	3,399	10,265	9,901
Operating income	1,536	1,375	3,473	3,225
Other income (expense):				
Interest expense	(475)	(423)	(1,423)	(1,266)
Capitalized interest	18	20	69	71
Allowance for equity funds	23	23	84	75
Interest and dividend income	27	10	79	28
Other, net	(9)	8	27	31
Total other income (expense)	(416)	(362)	(1,164)	(1,061)
Income before income tax expense and equity income	1,120	1,013	2,309	2,164
Income tax expense	269	266	474	531
Equity income	33	38	89	84
Net income	884	785	1,924	1,717
Net income attributable to noncontrolling interests	10	9	23	21
Net income attributable to BHE shareholders	$ 874	$ 776	$ 1,901	$ 1,696

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,	
	2015	2014	2015	2014
Net income	$ 884	$ 785	$ 1,924	$ 1,717
Other comprehensive (loss) income, net of tax:				
Unrecognized amounts on retirement benefits, net of tax of $7, $13, $4 and $13	16	40	10	44
Foreign currency translation adjustment	(318)	(214)	(479)	(83)
Unrealized (losses) gains on available-for-sale securities, net of tax of $(69), $79, $121 and $158	(103)	119	179	236
Unrealized (losses) gains on cash flow hedges, net of tax of $(6), $(5), $(9) and $8	(7)	(6)	(13)	13
Total other comprehensive (loss) income, net of tax	(412)	(61)	(303)	210
Comprehensive income	472	724	1,621	1,927
Comprehensive income attributable to noncontrolling interests	10	9	23	21
Comprehensive income attributable to BHE shareholders	$ 462	$ 715	$ 1,598	$ 1,906

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, 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, September 30, 2014	77	$ —	$ 6,423	$ 14,114	$ 113	$ 122	$ 20,772
Balance, December 31, 2014	77	$ —	$ 6,423	$ 14,513	$ (494)	$ 131	$ 20,573
Adoption of ASC 853	—	—	—	56	—	11	67
Net income	—	—	—	1,901	—	13	1,914
Other comprehensive loss	—	—	—	—	(303)	—	(303)
Distributions	—	—	—	—	—	(15)	(15)
Common stock purchases	—	—	(3)	(33)	—	—	(36)
Other equity transactions	—	—	(8)	—	—	(4)	(12)
Balance, September 30, 2015	77	$ —	$ 6,412	$ 16,437	$ (797)	$ 136	$ 22,188

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, 2015	2014
Cash flows from operating activities:		
Net income	$ 1,924	$ 1,717
Adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization	1,814	1,511
Allowance for equity funds	(84)	(75)
Equity income, net of distributions	(38)	(60)
Changes in regulatory assets and liabilities	326	(54)
Deferred income taxes and amortization of investment tax credits	617	1,063
Other, net	41	94
Changes in other operating assets and liabilities, net of effects from acquisitions:		
Trade receivables and other assets	(251)	(74)
Derivative collateral, net	8	(30)
Pension and other postretirement benefit plans	(9)	(23)
Accrued property, income and other taxes	1,608	201
Accounts payable and other liabilities	(47)	70
Net cash flows from operating activities	5,909	4,340
Cash flows from investing activities:		
Capital expenditures	(4,251)	(4,060)
Acquisitions, net of cash acquired	(157)	(246)
(Increase) decrease in restricted cash and investments	(64)	184
Purchases of available-for-sale securities	(132)	(131)
Proceeds from sales of available-for-sale securities	123	101
Equity method investments	(32)	(22)
Other, net	67	(6)
Net cash flows from investing activities	(4,446)	(4,180)
Cash flows from financing activities:		
Repayments of BHE senior debt and junior subordinated debentures	(600)	(550)
Common stock purchases	(36)	—
Proceeds from subsidiary debt	1,468	1,272
Repayments of subsidiary debt	(712)	(884)
Net (repayments of) proceeds from short-term debt	(473)	367
Other, net	(75)	(57)
Net cash flows from financing activities	(428)	148
Effect of exchange rate changes	(1)	(2)
Net change in cash and cash equivalents	1,034	306
Cash and cash equivalents at beginning of period	617	1,175
Cash and cash equivalents at end of period	$ 1,651	$ 1,481

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 eight business segments: 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 Powergrid Holdings Company ("Northern Powergrid") (which primarily consists of Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc), BHE Pipeline Group (which consists of Northern Natural Gas Company ("Northern Natural Gas") and Kern River Gas Transmission Company ("Kern River")), BHE Transmission (which consists of BHE AltaLink Ltd. ("AltaLink") (which primarily consists of AltaLink, L.P. ("ALP")) and BHE U.S. Transmission, LLC), BHE Renewables, and HomeServices of America, Inc. (collectively with its subsidiaries, "HomeServices"). The Company, through these businesses, owns four utility companies in the United States serving customers in 11 states, two electricity distribution companies in Great Britain, two interstate natural gas pipeline companies in the United States, an electric transmission business in Canada, interests in electric transmission businesses in the United States, a renewable energy business primarily selling power generated from solar, wind, geothermal and hydro sources under long-term contracts, the second largest residential real estate brokerage firm in the United States and one of the largest residential real estate brokerage franchise networks in the United States.

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, 2015 and for the three- and nine-month periods ended September 30, 2015 and 2014. The results of operations for the three- and nine-month periods ended September 30, 2015 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, 2014 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, 2015.

(2) New Accounting Pronouncements

In April 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2015-03, which amends FASB Accounting Standards Codification ("ASC") Subtopic 835-30, "Interest - Imputation of Interest." The amendments in this guidance require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability instead of as an asset. This guidance is effective for interim and annual reporting periods beginning after December 15, 2015, with early adoption permitted. This guidance must be adopted retrospectively, wherein the balance sheet of each period presented should be adjusted to reflect the new guidance. 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 May 2014, the FASB issued ASU No. 2014-09, which creates FASB 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. In August 2015, the FASB issued ASU No. 2015-14, which defers the effective date of ASU No. 2014-09 one year to interim and annual reporting periods beginning after December 15, 2017. 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 January 2014, the FASB issued ASU No. 2014-05, which amends FASB ASC Topic 853, "Service Concession Arrangements" ("ASC 853"). The amendments in this guidance require an entity to not account for service concession arrangements as a lease and should also not recognize them as property, plant and equipment. This guidance is effective for interim and annual reporting periods beginning after December 15, 2014. The Company adopted this guidance effective January 1, 2015 under a modified retrospective method where the cumulative effect is recognized at the date of initial application. The adoption resulted in the establishment of a financial asset with a related recognition of interest income, the elimination of a portion of previously recognized property, plant and equipment, the elimination of recognizing guaranteed water and energy delivery fees in operating revenue and increases to retained earnings attributable to the Company of $56 million and noncontrolling interests of $11 million.

(3) Business Acquisitions

AltaLink

Transaction Description

On December 1, 2014, BHE completed its acquisition of AltaLink and AltaLink became an indirect wholly owned subsidiary of BHE. Under the terms of the Share Purchase Agreement, dated May 1, 2014, between BHE and SNC-Lavalin Group Inc. ("SNC-Lavalin"), BHE paid C$3.1 billion (US$2.7 billion) in cash to SNC-Lavalin for 100% of the equity interests of AltaLink. BHE funded the total purchase price with $1.5 billion of junior subordinated debentures issued and sold to subsidiaries of Berkshire Hathaway, $1.0 billion borrowed under its commercial paper program and cash on hand.

ALP is a regulated electric transmission business, headquartered in Calgary, Alberta. ALP owns 7,800 miles of transmission lines and 300 substations in Alberta and operates under a cost-of-service regulatory model, including a forward test year, overseen by the Alberta Utilities Commission ("AUC").

Allocation of Purchase Price

The operations of ALP are subject to the rate-setting authority of the AUC and are accounted for pursuant to GAAP, including the authoritative guidance for regulated operations. The rate-setting and cost recovery provisions establish rates on a cost-of-service basis designed to allow ALP an opportunity to recover its costs of providing service and a return on its investment in rate base. Except for certain assets not currently in rates, the fair value of ALP's 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 AltaLink'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 contracts, deferred tax amounts and certain 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, further information regarding the fair value of the contracts and the resolution of contingency related items.

AltaLink's non-regulated assets acquired and liabilities assumed consist principally of AltaLink Investments, L.P.'s and AltaLink Holdings, L.P.'s senior bonds and debentures. The fair value of these liabilities 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 $15	$ 174
Property, plant and equipment	5,610
Goodwill	1,731
Other long-term assets	128
Total assets	7,643
Current liabilities, including current portion of long-term debt of $79	866
Subsidiary debt, less current portion	3,772
Deferred income taxes	95
Other long-term liabilities	182
Total liabilities	4,915
Net assets acquired	$ 2,728

Goodwill

The excess of the purchase price paid over the estimated fair values of the identifiable assets acquired and liabilities assumed totaled $1.7 billion and is reflected as goodwill in the BHE Transmission reportable segment. The goodwill reflects the value for the opportunities to invest in Alberta's electric transmission infrastructure and to develop solutions to meet the long-term energy needs of Alberta. 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, non-recurring transaction costs incurred by both BHE and AltaLink during 2014 and the amortization of the purchase price adjustments each assuming the acquisition had taken place on January 1, 2013 (in millions):

	Nine-Month Period Ended September 30, 2014
Operating revenue	$ 13,565
Net income attributable to BHE shareholders	$ 1,736

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.

(4) Property, Plant and Equipment, Net

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

	Depreciable Life	As of September 30, 2015	As of December 31, 2014
Regulated assets:			
Utility generation, distribution and transmission system	5-80 years	$ 67,044	$ 64,645
Interstate pipeline assets	3-80 years	6,761	6,660
		73,805	71,305
Accumulated depreciation and amortization		(22,666)	(21,447)
Regulated assets, net		51,139	49,858
Nonregulated assets:			
Independent power plants	5-30 years	4,737	4,362
Other assets	3-30 years	837	673
		5,574	5,035
Accumulated depreciation and amortization		(742)	(839)
Nonregulated assets, net		4,832	4,196
Net operating assets		55,971	54,054
Construction work-in-progress		4,160	5,194
Property, plant and equipment, net		$ 60,131	$ 59,248

Construction work-in-progress includes $3.9 billion and $4.3 billion as of September 30, 2015 and December 31, 2014, respectively, related to the construction of regulated assets.

(5) Regulatory Matters

Utah Mine Disposition

Due to quality issues with the coal reserves at PacifiCorp's Deer Creek mine in Utah and rising costs at PacifiCorp's wholly owned subsidiary, Energy West Mining Company, PacifiCorp believes the Deer Creek coal reserves are no longer able to be economically mined. As a result, in December 2014, PacifiCorp filed applications with the Utah Public Service Commission ("UPSC"), the Oregon Public Utility Commission ("OPUC"), the Wyoming Public Service Commission ("WPSC") and the Idaho Public Utilities Commission ("IPUC") seeking certain approvals, prudence determinations and accounting orders to close its Deer Creek mining operations, sell certain Utah mining assets, enter into a replacement coal supply agreement, amend an existing coal supply agreement, withdraw from the United Mine Workers of America ("UMWA") 1974 Pension Plan and settle PacifiCorp's other postretirement benefit obligation for UMWA participants (collectively, the "Utah Mine Disposition").

In April 2015, PacifiCorp filed all-party settlement stipulations with the UPSC and the WPSC finding that the decision to enter into the Utah Mine Disposition transaction is prudent and in the public interest. The UPSC approved the stipulation in April 2015 and the WPSC approved the stipulation in May 2015. In May 2015, the OPUC issued its final order concluding that the Utah Mine Disposition transaction produces net benefits for customers and is in the public interest. The IPUC also issued an order in May 2015, approving the Utah Mine Disposition and ruling that the decision to enter into the transaction is prudent and in the public interest. Accordingly, in June 2015, PacifiCorp sold the specified Utah mining assets and the replacement and amended coal supply agreements became effective. Refer to Note 13 for discussion of the contractual obligations related to the replacement coal supply agreement. Refer to Note 9 for discussion of the settlement of the other postretirement benefit obligation for UMWA participants. The Deer Creek mine is currently idled and closure activities have begun.

(6) Investments and Restricted Cash and Investments

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

	As of	
	September 30, 2015	December 31, 2014
Investments:		
BYD Company Limited common stock	$ 1,186	$ 881
Rabbi trusts	372	386
Other	139	126
Total investments	1,697	1,393
Equity method investments:		
Electric Transmission Texas, LLC	565	515
Bridger Coal Company	189	192
Other	184	161
Total equity method investments	938	868
Restricted cash and investments:		
Quad Cities Station nuclear decommissioning trust funds	415	424
Solar Star and Topaz Projects	125	66
Other	153	167
Total restricted cash and investments	693	657
Total investments and restricted cash and investments	$ 3,328	$ 2,918
Reflected as:		
Current assets	$ 202	$ 115
Noncurrent assets	3,126	2,803
Total investments and restricted cash and investments	$ 3,328	$ 2,918

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"). The fair value of BHE's investment in BYD Company Limited common stock reflects a pre-tax unrealized gain of $954 million and $649 million as of September 30, 2015 and December 31, 2014, respectively.

(7) Recent Financing Transactions

Long-Term Debt

In October 2015, MidAmerican Energy issued $200 million of its 3.50% First Mortgage Bonds due October 2024 and $450 million of its 4.25% First Mortgage Bonds due May 2046. The net proceeds will be used for the repayment of $426 million of long-term debt maturing December 31, 2015, and for general corporate purposes.

In September 2015, TX Jumbo Road Wind, LLC issued a $230 million Term Loan due September 2025. The Term Loan has an underlying variable interest rate based on LIBOR plus a fixed credit spread with a one-time increase during the term of the loan. The Company has entered into interest rate swaps that fix the underlying interest rate on 100% of the outstanding debt.

In June 2015, BHE repaid at par value $600 million, plus accrued interest, of its junior subordinated debentures due December 2043.

In June 2015, PacifiCorp issued $250 million of its 3.35% First Mortgage Bonds due July 2025. The net proceeds were used to fund capital expenditures and for general corporate purposes, including retirement of short-term debt.

In June 2015, ALP issued C$350 million of its 4.09% Series 2015-1 Medium-Term Notes due June 2045. The net proceeds were used to repay short-term debt.

In April 2015, Northern Powergrid (Yorkshire) plc issued £150 million of its 2.50% Bonds due April 2025. The net proceeds were used for general corporate purposes, including the repayment of short-term debt.

In March 2015, Solar Star Funding, LLC issued $325 million of its 3.95% Series B Senior Secured Notes. The principal of the notes amortizes beginning June 2016 with a final maturity in June 2035. The net proceeds were used to fund the repayment or reimbursement of amounts provided by BHE for the costs related to the development, construction and financing of a combined 586-megawatt solar project in California (the "Solar Star Projects").

In March 2015, AltaLink Investments, L.P. issued C$200 million of its 2.244% Series 15-1 Senior Bonds due March 2022. The net proceeds were used to repay short-term debt, provide equity to ALP and for general corporate purposes.

Credit Facilities

In March 2015, Topaz Solar Farms LLC amended its $345 million letter of credit facility reducing the amount available to $326 million and extending the maturity date to March 2025. As of September 30, 2015, Topaz had $316 million of letters of credit issued under this facility.

In March 2015, PacifiCorp obtained $191 million of letters of credit to support variable-rate tax-exempt bond obligations. These letters of credit expire through March 2017 and replace certain letters of credit previously issued under one of the credit facilities. Also, in March 2015, PacifiCorp arranged for the cancellation of $23 million of letters of credit previously issued under one of the credit facilities to support variable-rate tax-exempt bond obligations.

As of September 30, 2015, PacifiCorp had $310 million of fully available letters of credit issued under committed arrangements to support variable-rate tax-exempt bond obligations, of which $10 million were issued under credit facilities.

(8) 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,	
	2015	2014	2015	2014
Federal statutory income tax rate	35%	35%	35%	35%
Income tax credits	(9)	(10)	(11)	(10)
State income tax, net of federal income tax benefit	—	2	1	2
Income tax effect of foreign income and credits	(1)	(2)	(4)	(3)
Equity income	1	1	1	1
Other, net	(2)	—	(1)	—
Effective income tax rate	24%	26%	21%	25%

Income tax credits relate primarily to production tax credits from wind-powered generating facilities owned by MidAmerican Energy, PacifiCorp, Bishop Hill Energy II LLC and Jumbo Road Holdings, 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.

Berkshire Hathaway includes the Company in its United States federal income tax return. For the nine-month periods ended September 30, 2015 and 2014, the Company received net cash payments for income taxes from Berkshire Hathaway totaling $1.8 billion and $764 million, respectively.

(9) 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,	
	2015	2014	2015	2014
Pension:				
Service cost	$ 8	$ 11	$ 24	$ 28
Interest cost	30	32	91	98
Expected return on plan assets	(42)	(41)	(127)	(123)
Net amortization	13	8	41	28
Net periodic benefit cost	$ 9	$ 10	$ 29	$ 31
Other postretirement:				
Service cost	$ 2	$ 4	$ 8	$ 11
Interest cost	6	11	22	34
Expected return on plan assets	(10)	(14)	(33)	(39)
Net amortization	(1)	(1)	(7)	(3)
Net periodic benefit cost	$ (3)	$ —	$ (10)	$ 3

Employer contributions to the domestic pension and other postretirement benefit plans are expected to be $34 million and $2 million, respectively, during 2015. As of September 30, 2015, $8 million and $2 million of contributions had been made to the domestic pension and other postretirement benefit plans, respectively.

Utah Mine Disposition and Labor Agreement

In conjunction with the Utah Mine Disposition described in Note 5, in December 2014, Energy West Mining Company reached a labor settlement with the UMWA covering union employees at PacifiCorp's Deer Creek mining operations. As a result of the labor settlement, the UMWA agreed to assume PacifiCorp's other postretirement benefit obligation associated with UMWA plan participants in exchange for PacifiCorp transferring $150 million to a fund managed by the UMWA. Transfer of the assets and settlement of this obligation occurred in May 2015 and resulted in a remeasurement of the other postretirement plan assets and benefit obligation. As a result of the remeasurement, PacifiCorp recognized a $9 million settlement loss, with the portion that is probable of recovery deferred as a regulatory asset.

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,	
	2015	**2014**	**2015**	**2014**
Service cost	$ 6	$ 6	$ 18	$ 18
Interest cost	20	24	60	72
Expected return on plan assets	(29)	(31)	(87)	(94)
Net amortization	17	12	49	39
Net periodic benefit cost	$ 14	$ 11	$ 40	$ 35

Employer contributions to the United Kingdom pension plan are expected to be £49 million during 2015. As of September 30, 2015, £37 million, or $57 million, of contributions had been made to the United Kingdom pension plan.

(10) Asset Retirement Obligations

In December 2014, the United States Environmental Protection Agency released its final rule regulating the management and disposal of coal combustion byproducts resulting from the operation of coal-fueled generating facilities, including requirements for the operation and closure of surface impoundment and ash landfill facilities. The final rule was published in the Federal Register in April 2015 and was effective in October 2015. As of September 30, 2015 and December 31, 2014, the Company's asset retirement obligations totaled $803 million and $687 million, respectively, and the change was substantially due to the impacts of the final rule.

(11) 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, which creates contractual obligations to provide electric and natural gas services. 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, future debt issuances and mortgage commitments. Additionally, the Company is exposed to foreign currency exchange rate risk from its business operations and investments in Great Britain and Canada. 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, forward sale commitments, or mortgage interest rate lock commitments, 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 12 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, 2015					
Not designated as hedging contracts:					
Commodity assets[1]	$ 28	$ 76	$ 12	$ 2	$ 118
Commodity liabilities[1]	(4)	—	(115)	(182)	(301)
Interest rate assets	7	—	—	—	7
Interest rate liabilities	—	—	(6)	(8)	(14)
Total	31	76	(109)	(188)	(190)
Designated as hedging contracts:					
Commodity assets	1	—	2	—	3
Commodity liabilities	—	—	(25)	(25)	(50)
Interest rate assets	—	1	—	—	1
Interest rate liabilities	—	—	(5)	(2)	(7)
Total	1	1	(28)	(27)	(53)
Total derivatives	32	77	(137)	(215)	(243)
Cash collateral receivable	—	—	33	62	95
Total derivatives - net basis	$ 32	$ 77	$ (104)	$ (153)	$ (148)

As of December 31, 2014	Other Current Assets	Other Assets	Other Current Liabilities	Other Long-term Liabilities	Total
Not designated as hedging contracts:					
Commodity assets[1]	$ 47	$ 66	$ 21	$ 1	$ 135
Commodity liabilities[1]	(11)	—	(146)	(134)	(291)
Interest rate assets	4	—	—	—	4
Interest rate liabilities	—	—	(2)	(4)	(6)
Total	40	66	(127)	(137)	(158)
Designated as hedging contracts:					
Commodity assets	1	—	5	2	8
Commodity liabilities	—	—	(27)	(17)	(44)
Interest rate assets	—	1	—	—	1
Interest rate liabilities	—	—	(4)	—	(4)
Total	1	1	(26)	(15)	(39)
Total derivatives	41	67	(153)	(152)	(197)
Cash collateral receivable	—	—	56	19	75
Total derivatives - net basis	$ 41	$ 67	$ (97)	$ (133)	$ (122)

(1) The Company's commodity derivatives not designated as hedging contracts are generally included in regulated rates, and as of September 30, 2015 and December 31, 2014, a net regulatory asset of $253 million and $223 million, respectively, was recorded related to the net derivative liability of $183 million and $156 million, respectively. The difference between the net regulatory asset and the net derivative liability relates primarily to a power purchase agreement derivative at BHE Renewables.

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,	
	2015	2014	2015	2014
Beginning balance	$ 233	$ 142	$ 223	$ 182
Changes in fair value recognized in net regulatory assets	47	37	104	30
Net (losses) gains reclassified to operating revenue	(11)	5	(4)	(30)
Net losses reclassified to cost of sales	(16)	(11)	(70)	(9)
Ending balance	$ 253	$ 173	$ 253	$ 173

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 ("OCI"), as well as amounts reclassified to earnings (in millions):

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2015	2014	2015	2014
Beginning balance	$ 38	$ (25)	$ 32	$ 12
Changes in fair value recognized in OCI	20	16	37	(61)
Net gains reclassified to operating revenue	1	—	4	—
Net (losses) gains reclassified to cost of sales	(14)	(5)	(28)	35
Ending balance	$ 45	$ (14)	$ 45	$ (14)

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, 2015 and 2014, hedge ineffectiveness was insignificant. As of September 30, 2015, the Company had cash flow hedges with expiration dates extending through September 2025 and $25 million of pre-tax net unrealized losses are forecasted to be reclassified from AOCI into earnings over the next twelve months as contracts settle.

Derivative Contract Volumes

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

	Unit of Measure	September 30, 2015	December 31, 2014
Electricity purchases	Megawatt hours	7	6
Natural gas purchases	Decatherms	353	308
Fuel purchases	Gallons	3	2
Interest rate swaps	US$	662	443
Mortgage sale commitments, net	US$	(341)	(264)

Credit Risk

The Utilities are exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent the Utilities' counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, the Utilities analyze the financial condition of each significant wholesale counterparty, 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 further mitigate wholesale counterparty credit risk, 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. If required, the Utilities exercise rights under these arrangements, including calling on the counterparty's credit support arrangement.

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, 2015, 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 $290 million and $243 million as of September 30, 2015 and December 31, 2014, respectively, for which the Company had posted collateral of $71 million and $28 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, 2015 and December 31, 2014, the Company would have been required to post $204 million and $182 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.

(12) 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, 2015					
Assets:					
Commodity derivatives	$ —	$ 29	$ 92	$ (20)	$ 101
Interest rate derivatives	—	1	7	—	8
Mortgage loans held for sale	—	367	—	—	367
Money market mutual funds[2]	976	—	—	—	976
Debt securities:					
United States government obligations	136	—	—	—	136
International government obligations	—	2	—	—	2
Corporate obligations	—	40	—	—	40
Municipal obligations	—	2	—	—	2
Agency, asset and mortgage-backed obligations	—	3	—	—	3
Auction rate securities	—	—	44	—	44
Equity securities:					
United States companies	225	—	—	—	225
International companies	1,191	—	—	—	1,191
Investment funds	149	—	—	—	149
	$ 2,677	$ 444	$ 143	$ (20)	$ 3,244
Liabilities:					
Commodity derivatives	$ (12)	$ (290)	$ (49)	$ 115	$ (236)
Interest rate derivatives	—	(21)	—	—	(21)
	$ (12)	$ (311)	$ (49)	$ 115	$ (257)

	Input Levels for Fair Value Measurements					
	Level 1	Level 2	Level 3	Other[1]	Total
As of December 31, 2014					
Assets:					
Commodity derivatives	$ 1	$ 48	$ 94	$ (40)	$ 103
Interest rate derivatives	—	5	—	—	5
Mortgage loans held for sale	—	279	—	—	279
Money market mutual funds[2]	320	—	—	—	320
Debt securities:					
United States government obligations	136	—	—	—	136
International government obligations	—	1	—	—	1
Corporate obligations	—	39	—	—	39
Municipal obligations	—	2	—	—	2
Agency, asset and mortgage-backed obligations	—	2	—	—	2
Auction rate securities	—	—	45	—	45
Equity securities:					
United States companies	238	—	—	—	238
International companies	886	—	—	—	886
Investment funds	137	—	—	—	137
	$ 1,718	$ 376	$ 139	$ (40)	$ 2,193
Liabilities:					
Commodity derivatives	$ (18)	$ (274)	$ (43)	$ 115	$ (220)
Interest rate derivatives	—	(10)	—	—	(10)
	$ (18)	$ (284)	$ (43)	$ 115	$ (230)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $95 million and $75 million as of September 30, 2015 and December 31, 2014, 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 11 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 stated at fair value and are primarily accounted for as available-for-sale securities. 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	Interest Rate Derivatives	Auction Rate Securities	Commodity Derivatives	Interest Rate Derivatives	Auction Rate Securities
2015:						
Beginning balance	$ 34	$ 5	$ 45	$ 51	$ —	$ 45
Changes included in earnings	6	25	—	17	70	—
Changes in fair value recognized in OCI	(2)	—	(1)	(5)	—	(1)
Changes in fair value recognized in net regulatory assets	(4)	—	—	(21)	—	—
Purchases	—	—	—	1	—	—
Settlements	9	(23)	—	—	(66)	—
Transfers from Level 2	—	—	—	—	3	—
Ending balance	$ 43	$ 7	$ 44	$ 43	$ 7	$ 44
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

The Company's long-term debt is carried at cost on the Consolidated Balance Sheets. 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, 2015		As of December 31, 2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 38,245	$ 42,342	$ 38,649	$ 43,863

(13) 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 a May 2010 ruling on the Plaintiff's petition for reconsideration, the Utah Supreme Court reversed summary judgment and remanded the case back to the Third District Court for further consideration. In May 2012, a 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. 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. 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. 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 were heard in September 2015. As of September 30, 2015, PacifiCorp had accrued $121 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.

Commitments

As a result of the Utah Mine Disposition discussed in Note 5, PacifiCorp's replacement coal supply agreement for one of its generating facilities became effective in June 2015. Also during the three-month period ended June 30, 2015, PacifiCorp entered into several purchased electricity contracts from facilities that have not yet achieved commercial operation. These coal supply and purchased electricity contracts result in minimum future purchases of $70 million in 2016, $112 million in 2017, $127 million in 2018, $127 million in 2019 and $1.6 billion in 2020 and thereafter.

During the three-month period ended September 30, 2015, MidAmerican Energy entered into several contracts totaling $541 million for the construction of wind-powered generating facilities to be placed in-service in 2016, for which all of the purchase obligation is expected to be paid by the end of 2016. During the nine-month period ended September 30, 2015, MidAmerican Energy also entered into non-cancelable easements totaling $115 million with minimum commitments ranging through 2048 and non-cancelable maintenance and service contracts totaling $73 million with minimum commitments ranging through 2021. The easements and maintenance and service contracts relate to MidAmerican Energy's wind-powered generating facilities being placed in-service in 2015 and 2016.

The Solar Star Projects, which are a combined 586-MW solar project in California, achieved commercial operations under the power purchase agreements effective July 2015. BHE committed to provide Solar Star Funding, LLC and its subsidiaries with equity to fund the costs of the Solar Star Projects in an amount up to $2.75 billion, 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, 2015, the remaining equity commitment for the Solar Star Projects is $69 million. Upon reaching the project completion date of the Solar Star Projects, BHE will have no further obligation to make any equity contributions and any unused equity contribution obligation will be canceled under the equity commitment agreement.

In March 2015, the equity commitment for the Topaz Project was canceled as the project reached the project completion date.

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.

(14) Components of 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, 2013	$ (559)	$ (98)	$ 524	$ 36	$ (97)
Other comprehensive income (loss)	44	(83)	236	13	210
Balance, September 30, 2014	$ (515)	$ (181)	$ 760	$ 49	$ 113
Balance, December 31, 2014	$ (490)	$ (412)	$ 390	$ 18	$ (494)
Other comprehensive income (loss)	10	(479)	179	(13)	(303)
Balance, September 30, 2015	$ (480)	$ (891)	$ 569	$ 5	$ (797)

Reclassifications from AOCI to net income for the periods ended September 30, 2015 and 2014 were insignificant. For information regarding cash flow hedge reclassifications from AOCI to net income in their entirety, refer to Note 11. Additionally, refer to the "Foreign Operations" discussion in Note 9 for information about unrecognized amounts on retirement benefits reclassifications from AOCI that do not impact net income in their entirety.

(15) Segment Information

The Company's reportable segments with foreign operations include Northern Powergrid, whose business is principally in the United Kingdom, BHE Transmission, whose business includes operations in Canada, and BHE 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,	
	2015	2014	2015	2014
Operating revenue:				
PacifiCorp	$ 1,423	$ 1,438	$ 3,942	$ 3,969
MidAmerican Funding	921	864	2,669	2,869
NV Energy	1,124	1,118	2,665	2,551
Northern Powergrid	265	306	852	947
BHE Pipeline Group	196	188	736	800
BHE Transmission	153	—	428	—
BHE Renewables	269	244	583	458
HomeServices	745	644	1,951	1,619
BHE and Other[1]	(27)	(28)	(88)	(87)
Total operating revenue	$ 5,069	$ 4,774	$ 13,738	$ 13,126
Depreciation and amortization:				
PacifiCorp	$ 194	$ 189	$ 584	$ 555
MidAmerican Funding	101	89	300	259
NV Energy	103	96	307	283
Northern Powergrid	50	52	148	150
BHE Pipeline Group	51	48	151	146
BHE Transmission	56	—	147	—
BHE Renewables	55	47	160	100
HomeServices	8	8	20	23
BHE and Other[1]	(1)	(2)	(3)	(5)
Total depreciation and amortization	$ 617	$ 527	$ 1,814	$ 1,511
Operating income:				
PacifiCorp	$ 437	$ 419	$ 1,037	$ 1,054
MidAmerican Funding	211	161	440	365
NV Energy	398	396	697	682
Northern Powergrid	129	158	452	517
BHE Pipeline Group	66	59	322	318
BHE Transmission	62	(4)	166	(8)
BHE Renewables	153	143	225	252
HomeServices	78	62	161	101
BHE and Other[1]	2	(19)	(27)	(56)
Total operating income	1,536	1,375	3,473	3,225
Interest expense	(475)	(423)	(1,423)	(1,266)
Capitalized interest	18	20	69	71
Allowance for equity funds	23	23	84	75
Interest and dividend income	27	10	79	28
Other, net	(9)	8	27	31
Total income before income tax expense and equity income	$ 1,120	$ 1,013	$ 2,309	$ 2,164

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2015	2014	2015	2014
Interest expense:				
PacifiCorp	$ 97	$ 96	$ 287	$ 291
MidAmerican Funding	50	50	150	147
NV Energy	67	70	195	211
Northern Powergrid	37	38	108	114
BHE Pipeline Group	16	19	51	57
BHE Transmission	37	—	110	—
BHE Renewables	49	46	144	128
HomeServices	1	1	3	3
BHE and Other[1]	121	103	375	315
Total interest expense	$ 475	$ 423	$ 1,423	$ 1,266

	As of	
	September 30, 2015	December 31, 2014
Total assets:		
PacifiCorp	$ 23,534	$ 23,466
MidAmerican Funding	16,099	15,368
NV Energy	14,756	14,454
Northern Powergrid	7,282	7,076
BHE Pipeline Group	4,914	4,968
BHE Transmission	7,682	7,992
BHE Renewables	5,867	6,123
HomeServices	1,806	1,629
BHE and Other[1]	1,819	1,228
Total assets	$ 83,759	$ 82,304

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2015	2014	2015	2014
Operating revenue by country:				
United States	$ 4,643	$ 4,433	$ 12,444	$ 12,089
United Kingdom	265	306	852	945
Canada	154	3	434	13
Philippines and other	7	32	8	79
Total operating revenue by country	$ 5,069	$ 4,774	$ 13,738	$ 13,126

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2015	2014	2015	2014
Income (loss) before income tax expense and equity income by country:				
United States	$ 962	$ 874	$ 1,785	$ 1,717
United Kingdom	98	126	364	411
Canada	41	(4)	119	(8)
Philippines and other	19	17	41	44
Total income (loss) before income tax expense and equity income by country	$ 1,120	$ 1,013	$ 2,309	$ 2,164

(1) The differences between the reportable segment amounts and the consolidated amounts, described as BHE and Other, relate to other corporate entities, corporate functions 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, 2015 (in millions):

	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	Home-Services	Other	Total
December 31, 2014	$ 1,129	$ 2,102	$ 2,369	$ 1,100	$ 127	$ 1,657	$ 95	$ 761	$ 3	$9,343
Acquisitions	—	—	—	—	—	31	—	27	—	58
Foreign currency translation	—	—	—	(23)	—	(216)	—	—	—	(239)
Other	—	—	—	—	(19)	—	—	—	—	(19)
September 30, 2015	$ 1,129	$ 2,102	$ 2,369	$ 1,077	$ 108	$ 1,472	$ 95	$ 788	$ 3	$9,143

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 eight business segments: PacifiCorp, MidAmerican Funding (which primarily consists of MidAmerican Energy), NV Energy (which primarily consists of Nevada Power and Sierra Pacific), Northern Powergrid (which primarily consists of Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc), BHE Pipeline Group (which consists of Northern Natural Gas and Kern River), BHE Transmission (which consists of AltaLink and BHE U.S. Transmission), BHE Renewables, and HomeServices. The Company, through these businesses, owns four utility companies in the United States serving customers in 11 states, two electricity distribution companies in Great Britain, two interstate natural gas pipeline companies in the United States, an electric transmission business in Canada, interests in electric transmission businesses in the United States, a renewable energy business primarily selling power generated from solar, wind, hydro and geothermal sources under long-term contracts, the second largest residential real estate brokerage firm in the United States and one of the largest residential real estate brokerage franchise networks in the United States. 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 principally to other corporate entities, corporate functions and intersegment eliminations.

Results of Operations for the Third Quarter and First Nine Months of 2015 and 2014

Overview

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

	Third Quarter				First Nine Months			
	2015	2014	Change		2015	2014	Change	
Net income attributable to BHE shareholders:								
PacifiCorp	$ 245	$ 239	$ 6	3%	$ 551	$ 579	$ (28)	(5)%
MidAmerican Funding	231	168	63	38	459	353	106	30
NV Energy	219	213	6	3	341	318	23	7
Northern Powergrid	77	94	(17)	(18)	281	315	(34)	(11)
BHE Pipeline Group	32	27	5	19	168	166	2	1
BHE Transmission	46	12	34	*	137	34	103	*
BHE Renewables	74	69	5	7	109	100	9	9
HomeServices	44	34	10	29	91	55	36	65
BHE and Other	(94)	(80)	(14)	(18)	(236)	(224)	(12)	(5)
Total net income attributable to BHE shareholders	$ 874	$ 776	$ 98	13	$ 1,901	$ 1,696	$ 205	12

* Not meaningful

Net income attributable to BHE shareholders increased $98 million for the third quarter of 2015 compared to 2014 due to the following:

- PacifiCorp's net income increased due to higher margins of $19 million, partially offset by lower AFUDC of $4 million. Margins increased primarily due to lower purchased electricity prices, lower natural gas costs, higher retail rates and lower coal generation, partially offset by higher purchased electricity volumes, lower retail customer load and lower wholesale electricity revenue. Customer load decreased 2.6% due to lower industrial customer usage in Utah and Wyoming, partially offset by an increase in the average number of residential and commercial customers primarily in Utah.

- MidAmerican Funding's net income increased due to higher regulated electric margins of $60 million and lower income tax expense due to higher recognized production tax credits of $29 million and the impacts of rate making of $13 million, partially offset by higher depreciation and amortization of $12 million due to wind-powered generation and other plant placed in-service and lower AFUDC of $8 million. Regulated electric margins increased primarily due to higher retail rates and changes in rate structure related to seasonal pricing, higher retail customer load, a lower average cost of fuel for generation and lower purchased power costs, partially offset by lower wholesale revenue. Electric retail customer load increased 6.7% compared to 2014 as a result of warmer temperatures and industrial growth.
- NV Energy's net income increased due to higher regulated electric margins of $20 million and lower interest expense of $3 million, partially offset by higher operating expense of $11 million and higher depreciation and amortization of $7 million due to higher regulatory amortizations. Regulated electric margins increased primarily due to higher retail customer load and higher energy efficiency rate revenue, which is offset in operating expense, partially offset by lower retail rates as a result of a rate design change from the 2014 Nevada Power general rate case effective January 2015. Electric retail customer load increased 1.8% compared to 2014 due to the impacts of weather and customer growth.
- Northern Powergrid's net income decreased due to lower distribution revenues of $19 million and the stronger United States dollar of $6 million. Distribution revenue decreased due to lower tariff rates of $43 million mainly reflecting the impact of the new price control period effective April 1, 2015, partially offset by the recovery of the December 2013 customer rebate of $12 million and favorable movements in regulatory provisions of $13 million.
- BHE Pipeline Group's net income increased due to higher transportation and storage revenue due to expansion projects and higher storage rates.
- BHE Transmission's net income increased $34 million due to the acquisition of AltaLink on December 1, 2014. Operating revenue and operating income for the third quarter of 2015 from AltaLink was $153 million and $64 million, respectively.
- BHE Renewables' net income increased due primarily to additional solar capacity at the Solar Star Project being placed in service, partially offset by lower income from changes in the valuations of a power purchase agreement derivative and interest rate swap derivatives.
- HomeServices' net income increased due to higher earnings at existing businesses from a 9.1% increase in closed brokerage units and higher closed title units.
- BHE and Other net loss increased due primarily to higher interest expense of $21 million due to the issuance of $1.5 billion of BHE senior debt in December 2014 and $1.5 billion of junior subordinated debentures to certain Berkshire Hathaway subsidiaries in the fourth quarter of 2014, partially offset by the repayment of junior subordinated debentures totaling $600 million in June 2015.

Net income attributable to BHE shareholders increased $205 million for the first nine months of 2015 compared to 2014 due to the following:

- PacifiCorp's net income decreased due to the prior year recognition of insurance recoveries for fire claims, higher depreciation and amortization of $29 million and lower AFUDC of $20 million, partially offset by higher margins of $42 million. Margins increased primarily due to higher retail rates, lower purchased electricity prices and lower natural gas generation and costs, partially offset by higher purchased electricity volumes, lower retail customer load, lower wholesale electricity revenue, lower renewable energy credit revenue and higher coal costs. Customer load decreased 1.5% due to lower industrial customer usage in Utah and Wyoming and lower residential customer usage across the service territory, partially offset by an increase in the average number of residential customers in Utah and Oregon and an increase in the average number of commercial customers in Utah.
- MidAmerican Funding's net income increased due to higher regulated electric margins of $111 million, higher recognized production tax credits of $45 million and lower fossil-fueled generation maintenance of $19 million, partially offset by higher depreciation and amortization of $41 million due to wind-powered generation and other plant placed in-service and lower AFUDC of $20 million. Regulated electric margins increased primarily due to higher retail rates and changes in rate structure related to seasonal pricing, lower purchased power costs, a lower average cost of fuel for generation, higher transmission revenue and higher retail customer load, partially offset by lower wholesale revenue. Electric retail customer load increased 1.9% compared to 2014 primarily as a result of strong industrial growth.

- NV Energy's net income increased due to higher regulated electric margins of $56 million and lower interest expense of $16 million, partially offset by higher depreciation and amortization of $24 million due to higher regulatory amortizations and higher operating expense of $18 million. Regulated electric margins increased primarily due to higher retail customer load, higher retail rates as a result of a rate design change from the 2014 Nevada Power general rate case effective January 2015 and higher energy efficiency rate revenue, which is offset in operating expense. Electric retail customer load increased 1.4% compared to 2014 due to customer growth, partially offset by the impacts of weather.

- Northern Powergrid's net income decreased due to the stronger United States dollar of $26 million and lower distribution revenues of $9 million. Distribution revenue decreased due to lower tariff rates of $46 million, partially offset by the recovery of the December 2013 customer rebate of $25 million and favorable movements in regulatory provisions of $14 million.

- BHE Pipeline Group's net income increased due to higher transportation revenue and lower interest expense, partially offset by higher depreciation expense.

- BHE Transmission's net income increased due to the acquisition of AltaLink on December 1, 2014 totaling $98 million. Operating revenue and operating income for the first nine months of 2015 from AltaLink was $428 million and $168 million, respectively.

- BHE Renewables' net income increased primarily due to additional solar capacity at the Solar Star and Topaz Projects being placed in service and a favorable change in the valuation of a power purchase agreement derivative, partially offset by lower earnings at CE Generation and lower wind generation at existing projects.

- HomeServices' net income increased due to higher earnings at existing businesses from an increase in closed brokerage units, home sales prices, closed title units and mortgage units, and positive results at newly acquired businesses of $5 million.

- BHE and Other net loss increased due primarily to higher interest expense of $67 million, partially offset by favorable United States income taxes on foreign earnings.

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			
	2015	2014	Change		2015	2014	Change	
Operating revenue:								
PacifiCorp	$ 1,423	$ 1,438	$ (15)	(1)%	$ 3,942	$ 3,969	$ (27)	(1)%
MidAmerican Funding	921	864	57	7	2,669	2,869	(200)	(7)
NV Energy	1,124	1,118	6	1	2,665	2,551	114	4
Northern Powergrid	265	306	(41)	(13)	852	947	(95)	(10)
BHE Pipeline Group	196	188	8	4	736	800	(64)	(8)
BHE Transmission	153	—	153	*	428	—	428	*
BHE Renewables	269	244	25	10	583	458	125	27
HomeServices	745	644	101	16	1,951	1,619	332	21
BHE and Other	(27)	(28)	1	(4)	(88)	(87)	(1)	(1)
Total operating revenue	$ 5,069	$ 4,774	$ 295	6	$ 13,738	$ 13,126	$ 612	5
Operating income:								
PacifiCorp	$ 437	$ 419	$ 18	4%	$ 1,037	$ 1,054	$ (17)	(2)%
MidAmerican Funding	211	161	50	31	440	365	75	21
NV Energy	398	396	2	1	697	682	15	2
Northern Powergrid	129	158	(29)	(18)	452	517	(65)	(13)
BHE Pipeline Group	66	59	7	12	322	318	4	1
BHE Transmission	62	(4)	66	*	166	(8)	174	*
BHE Renewables	153	143	10	7	225	252	(27)	(11)
HomeServices	78	62	16	26	161	101	60	59
BHE and Other	2	(19)	21	*	(27)	(56)	29	52
Total operating income	$ 1,536	$ 1,375	$ 161	12	$ 3,473	$ 3,225	$ 248	8

* Not meaningful

PacifiCorp

Operating revenue decreased $15 million for the third quarter of 2015 compared to 2014 due to lower wholesale and other revenue from lower average wholesale prices of $12 million and lower average wholesale volumes of $5 million. Higher retail rates of $20 million were offset by lower retail customer load. Customer load decreased 2.6% due to lower industrial customer usage in Utah and Wyoming, partially offset by an increase in the average number of residential and commercial customers primarily in Utah.

Operating income increased $18 million for the third quarter of 2015 compared to 2014 due to higher margins of $19 million. Margins increased due to lower energy costs of $34 million, partially offset by the lower operating revenue. Energy costs decreased due to lower purchased electricity prices, a lower average cost of natural gas and lower coal and natural gas generation, partially offset higher purchased electricity volumes.

Operating revenue decreased $27 million for the first nine months of 2015 compared to 2014 due to lower wholesale and other revenue of $76 million, partially offset by higher retail revenue of $49 million. Wholesale and other revenue decreased due to lower wholesale volumes of $34 million, lower renewable energy credit revenue of $31 million and lower average wholesale prices of $11 million. The increase in retail revenue was due to higher retail rates of $94 million, partially offset by lower retail customer load of $45 million. Customer load decreased 1.5% due to lower industrial customer usage in Utah and Wyoming and lower residential customer usage across the service territory, partially offset by an increase in the average number of residential customers in Utah and Oregon and an increase in the average number of commercial customers in Utah. The impacts of mild weather in the first quarter of 2015 on residential and commercial customers primarily in Oregon and Washington and minimal weather impacts in the third quarter of 2015 were largely offset by the impacts of the hot weather in June 2015 on residential and commercial customers.

Operating income decreased $17 million for the first nine months of 2015 compared to 2014 due to the prior year recognition of insurance recoveries for fire claims and higher depreciation and amortization of $29 million primarily due to higher plant in-service including the Lake Side 2 natural gas-fueled generating facility placed in-service in May 2014, partially offset by higher margins of $42 million. Margins increased due to lower energy costs of $69 million, partially offset by the lower operating revenue. Energy costs decreased due to lower purchased electricity prices, lower natural gas generation and a lower average cost of natural gas, partially offset by higher purchased electricity volumes, lower net deferrals of incurred net power costs and a higher average cost of coal.

MidAmerican Funding

Operating revenue increased $57 million for the third quarter of 2015 compared to 2014 due primarily to higher regulated electric operating revenue of $46 million and higher nonregulated and other operating revenue of $16 million. Regulated electric operating revenue increased due to higher retail revenue of $65 million, partially offset by lower wholesale and other revenue of $19 million. Retail revenue increased due to $43 million from higher electric rates primarily in Iowa and $19 million from warmer temperatures. The increase in Iowa electric rates reflects higher retail rates and changes in rate structure related to seasonal pricing that were effective with the implementation of final base rates in August 2014 and result in a greater differential between higher rates from June to September and lower rates in the remaining months. Electric retail customer load increased 6.7% compared to 2014 as a result of warmer temperatures and industrial growth. Electric wholesale and other revenue decreased due to lower average wholesale prices of $14 million and lower wholesale volumes of $12 million, partially offset by higher transmission revenue of $5 million related to MidAmerican Energy's Multi-Value Projects. Nonregulated and other operating revenue increased due to higher electricity and natural gas volumes, partially offset by lower natural gas prices.

Operating income increased $50 million for the third quarter of 2015 compared to 2014 due primarily to higher regulated electric operating income of $52 million, which increased due to the higher retail rates and changes in retail rate structure related to seasonal pricing, the higher retail sales volumes and lower energy costs of $14 million from a lower average cost of fuel for generation and lower purchased power costs, partially offset by higher depreciation and amortization of $12 million, due to wind generation and other plant placed in-service, and the lower wholesale revenue.

Operating revenue decreased $200 million for the first nine months of 2015 compared to 2014 due to lower regulated natural gas operating revenue of $247 million and lower nonregulated and other operating revenue of $10 million, partially offset by higher regulated electric operating revenue of $57 million. Regulated natural gas operating revenue decreased due to a lower average per-unit cost of gas sold of $252 million, which is offset in cost of sales, and 13.6% lower retail sales volumes primarily from colder than normal winter temperatures in 2014, partially offset by higher wholesale volumes. Nonregulated and other operating revenue decreased due to lower natural gas prices and volumes of $69 million and lower construction services of $4 million, partially offset by higher electricity volumes and prices of $66 million. Regulated electric operating revenue increased due to higher retail revenue of $89 million, partially offset by lower wholesale and other revenue of $32 million. Retail revenue increased due to $57 million from higher electric rates primarily in Iowa, $24 million from higher recoveries through adjustment clauses, which is substantially offset in operating expense, and $8 million from non-weather-related customer load factors. Electric retail customer load increased 1.9% compared to 2014 primarily as a result of strong industrial growth. Electric wholesale and other revenue decreased primarily due to lower average wholesale prices of $53 million, partially offset by higher transmission revenue of $15 million related to MidAmerican Energy's Multi-Value Projects and higher wholesale volumes of $9 million.

Operating income increased $75 million for the first nine months of 2015 compared to 2014 due to higher regulated electric operating income of $82 million, partially offset by lower regulated natural gas operating income of $4 million and lower nonregulated and other operating income of $3 million. Regulated electric operating income increased due to lower energy costs of $54 million from lower purchased power costs and a lower average cost of fuel for generation, the higher retail rates and changes in rate structure related to seasonal pricing, the higher transmission revenue and lower fossil-fueled generation maintenance from the planned major outages in 2014 of $19 million, partially offset by higher depreciation and amortization of $41 million, due to wind generation and other plant placed in-service, and the lower wholesale revenue. Regulated natural gas operating income decreased due to lower retail sales volumes, partially offset by a one-time refund of $8 million to customers in 2014 of insurance recoveries related to environmental matters.

NV Energy

Operating revenue increased $6 million for the third quarter of 2015 compared to 2014 due primarily to higher regulated electric operating revenue of $3 million, which increased due to higher wholesale and other revenue of $4 million, partially offset by lower retail revenue of $1 million. Wholesale and other revenue increased due primarily to $3 million of higher transmission revenue. Retail revenue was lower due to $30 million from lower retail rates as a result of deferred energy adjustment mechanisms and a rate design change from the 2014 Nevada Power general rate case effective in January 2015, partially offset by $14 million from higher customer growth, $11 million from higher energy efficiency rate revenue, which is offset in operating expense, and $3 million from higher customer usage primarily due to the impacts of weather. Electric retail customer load increased 1.8% compared to 2014.

Operating income increased $2 million for the third quarter of 2015 compared to 2014 due to higher regulated electric margins of $20 million from the higher regulated electric operating revenue and lower energy costs of $15 million. Energy costs decreased due to a lower average cost of natural gas and coal of $47 million and lower purchased power costs of $23 million, partially offset by higher net deferred power costs of $55 million. The higher regulated electric margins were partially offset by higher operating expense of $11 million and higher depreciation and amortization of $7 million due to higher regulatory amortizations.

Operating revenue increased $114 million for the first nine months of 2015 compared to 2014 primarily due to higher regulated electric operating revenue of $98 million and higher regulated natural gas operating revenue of $11 million due primarily to a rate change. Regulated electric operating revenue increased due to higher retail revenue of $84 million and higher wholesale and other revenue of $14 million mainly from higher transmission revenue. Retail revenue was higher primarily due to $39 million from higher customer growth, $31 million from higher retail rates as a result of deferred energy adjustment mechanisms and a rate design change from the 2014 Nevada Power general rate case effective in January 2015 and $27 million of higher energy efficiency rate revenue, which is offset in operating expense, partially offset by $7 million lower customer usage primarily due to the impacts of weather. Electric retail customer load increased 1.4% compared to 2014.

Operating income increased $15 million for the first nine months of 2015 compared to 2014 due to higher regulated electric margins of $56 million from the higher regulated electric operating revenue, partially offset by higher energy costs of $47 million. Energy costs increased due to higher net deferred power costs of $228 million, partially offset by a lower average cost of natural gas and coal of $162 million and lower purchased power costs of $19 million. The higher regulated electric margins were partially offset by higher depreciation and amortization of $24 million due to higher regulatory amortizations and higher operating expense of $18 million.

Northern Powergrid

Operating revenue decreased $41 million for the third quarter of 2015 compared to 2014 due to the stronger United States dollar of $22 million and lower distribution revenue of $19 million. Distribution revenue decreased due to lower tariff rates of $43 million mainly reflecting the impact of the new price control period effective April 1, 2015, partially offset by the recovery of the December 2013 customer rebate of $12 million and favorable movements in regulatory provisions of $13 million. Operating income decreased $29 million for the third quarter of 2015 compared to 2014 primarily due to the lower distribution revenue and the stronger United States dollar of $10 million.

Operating revenue decreased $95 million for the first nine months of 2015 compared to 2014 due to the stronger United States dollar of $77 million, lower contracting and other revenue of $7 million and lower distribution revenue of $9 million. Distribution revenue decreased due to lower tariff rates of $46 million mainly reflecting the impact of the new price control period effective April 1, 2015, partially offset by the recovery of the December 2013 customer rebate of $25 million and favorable movements in regulatory provisions of $14 million. Operating income decreased $65 million for the first nine months of 2015 compared to 2014 due to the stronger United States dollar of $41 million, the lower distribution revenues, higher pension costs of $7 million and higher distribution related costs of $7 million.

BHE Pipeline Group

Operating revenue increased $8 million for the third quarter of 2015 compared to 2014 due to higher transportation revenue from expansion projects and higher storage revenue from higher rates. Operating income increased $7 million for the third quarter of 2015 compared to 2014 due to the higher transportation and storage revenue and lower operating expense of $3 million, partially offset by higher depreciation expense of $3 million.

Operating revenue decreased $64 million for the first nine months of 2015 compared to 2014 due to lower gas sales of $68 million related to system and operational balancing activities, partially offset by higher transportation revenues. Operating income increased $4 million for the first nine months of 2015 compared to 2014 due to the higher transportation revenue, partially offset by higher depreciation expense of $5 million. The lower revenue related to system and operational balancing activities was offset by lower costs of gas sold.

BHE Transmission

AltaLink was acquired on December 1, 2014, and its results are included in the consolidated results beginning as of that date. Operating revenue and operating income for the third quarter of 2015 from AltaLink was $153 million and $64 million, respectively. Operating revenue and operating income for the first nine months of 2015 from AltaLink was $428 million and $168 million, respectively.

BHE Renewables

Operating revenue increased $25 million for the third quarter of 2015 compared to 2014 due to an increase of $65 million as additional solar and wind capacity was placed in-service, partially offset by a $26 million decrease at CalEnergy Philippines, an unfavorable change in the valuation of a power purchase agreement derivative of $10 million and lower pricing at certain geothermal plants of $5 million. CalEnergy Philippines operating revenue decreased due to the adoption of Financial Accounting Standards Board Accounting Standards Codification Topic 853, "Service Concession Arrangements" ("ASC 853") on January 1, 2015, which resulted in the elimination of recognizing the guaranteed water and energy delivery fees in operating revenue and the establishment of a financial asset with a related recognition of interest income.

Operating income increased $10 million for the third quarter of 2015 compared to 2014 due to the higher operating revenue, partially offset by higher depreciation and amortization of $8 million and higher operating expense of $6 million. Depreciation and amortization increased due to $13 million from additional solar and wind capacity placed in-service, partially offset by a $6 million decrease at CalEnergy Philippines due to the adoption of ASC 853, which reclassified a portion of property, plant and equipment to a financial asset. Operating expense increased due to $8 million from additional solar and wind capacity placed in-service, partially offset by a $4 million reduction at certain geothermal plants.

Operating revenue increased $125 million for the first nine months of 2015 compared to 2014 due to an increase of $142 million as additional solar and wind capacity was placed in-service, an increase from the acquisition of the remaining 50% interest in CE Generation in June 2014 of $55 million and a favorable change in the valuation of a power purchase agreement derivative of $14 million, partially offset by a $69 million decrease at CalEnergy Philippines due to the adoption of ASC 853 and lower wind generation at existing projects.

Operating income decreased $27 million for the first nine months of 2015 compared to 2014 as the higher operating revenue was more than offset by higher operating expense of $92 million and higher depreciation and amortization of $60 million. Operating expense increased due to $69 million from the CE Generation acquisition, $19 million from additional solar and wind capacity placed in-service and higher project acquisition costs of $7 million. Depreciation and amortization increased due to $43 million from additional solar and wind capacity placed in-service and $33 million from the CE Generation acquisition, partially offset by a $17 million decrease at CalEnergy Philippines due to the adoption of ASC 853.

HomeServices

Operating revenue increased $101 million for the third quarter of 2015 compared to 2014 due to a 13.4% increase in closed brokerage units. The increase in operating revenue was due to an increase from existing businesses totaling $63 million and an increase in acquired businesses totaling $38 million. The increase in existing businesses reflects a 9.1% increase in closed brokerage units. Operating income increased $16 million for the third quarter of 2015 compared to 2014 due to the higher revenues at existing businesses, partially offset by higher costs, primarily commission expense, at existing businesses.

Operating revenue increased $332 million for the first nine months of 2015 compared to 2014 due to a 12.9% increase in closed brokerage units and a 4.3% increase in average home sales prices. The increase in operating revenue was due to an increase from existing businesses totaling $200 million and an increase in acquired businesses totaling $132 million. The increase in existing businesses reflects a 10.0% increase in closed brokerage units and a 2.6% increase in average home sales prices. Operating income increased $60 million for the first nine months of 2015 compared to 2014 due to higher revenues offset by higher costs, primarily commission expense, at existing businesses of $53 million and higher earnings at acquired businesses of $7 million.

BHE and Other

Operating loss improved $21 million for the third quarter and $29 million for the first nine months of 2015 compared to 2014 primarily due to lower other operating expense.

Consolidated Other Income and Expense Items

Interest Expense

Interest expense is summarized as follows (in millions):

	Third Quarter				First Nine Months			
	2015	**2014**	**Change**		**2015**	**2014**	**Change**	
Subsidiary debt	$ 351	$ 319	$ 32	10%	$ 1,038	$ 948	$ 90	9%
BHE senior debt and other	100	87	13	15	304	262	42	16
BHE junior subordinated debentures	24	17	7	41	81	56	25	45
Total interest expense	$ 475	$ 423	$ 52	12	$ 1,423	$ 1,266	$ 157	12

Interest expense on subsidiary debt increased $32 million for the third quarter and $90 million for the first nine months of 2015 compared to 2014 due to $37 million and $110 million, respectively, from the acquisition of AltaLink in December 2014 and $6 million for the first nine months of 2015 compared to 2014 from the acquisition of the remaining 50% interest in CE Generation in June 2014. Additionally, debt issuances at PacifiCorp ($250 million in June 2015), MidAmerican Funding ($850 million in April 2014), Northern Powergrid (£150 million in April 2015) and BHE Renewables ($325 million in March 2015) increased interest expense, partially offset by scheduled maturities and principal payments and the impact of the foreign currency exchange rate of $3 million and $10 million, respectively.

Interest expense on BHE senior debt and other increased $13 million for the third quarter and $42 million for the first nine months of 2015 compared to 2014 due to the issuance of $1.5 billion of BHE senior debt in December 2014.

Interest expense on BHE junior subordinated debentures increased $7 million for the third quarter and $25 million for the first nine months of 2015 compared to 2014 due to the issuance of $1.5 billion of junior subordinated debentures to certain Berkshire Hathaway subsidiaries in the fourth quarter of 2014, partially offset by the repayment of junior subordinated debentures totaling $600 million in June 2015 and $300 million in June 2014.

Capitalized Interest

Capitalized interest decreased $2 million for the third quarter and $2 million for the first nine months of 2015 compared to 2014 as $8 million and $30 million, respectively, from AltaLink was more than offset by lower construction work-in-progress balances at BHE Renewables, PacifiCorp and MidAmerican Energy.

Allowance for Equity Funds

Allowance for equity funds was flat for the third quarter and increased $9 million for the first nine months of 2015 compared to 2014 as $8 million and $34 million, respectively, from AltaLink was offset by lower construction work-in-progress balances at PacifiCorp and MidAmerican Energy.

Interest and Dividend Income

Interest and dividend income increased $17 million for the third quarter and $51 million for the first nine months of 2015 compared to 2014 primarily due to the recognition of interest income on the financial asset established as a result of the adoption of ASC 853 at CalEnergy Philippines.

Other, net

Other, net decreased $17 million for the third quarter of 2015 compared to 2014 primarily due to lower investment returns and unfavorable movements on interest rate swaps.

Other, net decreased $4 million for the first nine months of 2015 compared to 2014 primarily due to lower investment returns, partially offset by a gain on sale of a generating facility lease at MidAmerican Funding in 2015.

Income Tax Expense

Income tax expense increased $3 million for the third quarter of 2015 compared to 2014 and the effective tax rate was 24% for 2015 and 26% for 2014. The effective tax rate decreased due to favorable impacts of rate making of $22 million, favorable state income tax benefits of $9 million and higher production tax credits recognized of $5 million.

Income tax expense decreased $57 million for the first nine months of 2015 compared to 2014 and the effective tax rate was 21% for 2015 and 25% for 2014. The effective tax rate decreased due to favorable impacts of rate making of $43 million, favorable United States income taxes on foreign earnings of $29 million primarily due to foreign tax credits and higher production tax credits recognized of $17 million.

Production tax credits are recognized in earnings for interim periods based on the application of an estimated annual effective tax rate to pretax earnings. 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. Production tax credits recognized in the third quarter of 2015 were $102 million, or $5 million higher than 2014, while production tax credits earned in the third quarter of 2015 were $54 million, or $16 million higher than 2014. Production tax credits recognized in the first nine months of 2015 were $235 million, or $17 million higher than 2014, while production tax credits earned in the first nine months of 2015 were $197 million, or $17 million higher than 2014. The difference between production tax credits recognized and earned of $38 million as of September 30, 2015 will be reflected in earnings over the remainder of 2015.

Equity Income

Equity income decreased $5 million for the third quarter of 2015 compared to 2014 primarily due lower equity earnings at Electric Transmission Texas.

Equity income increased $5 million for the first nine months of 2015 compared to 2014 primarily due to the acquisition of the remaining 50% interest in CE Generation in June 2014, which incurred a loss in 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. 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, 2014 for further discussion regarding the limitation of distributions from BHE's subsidiaries.

The Company's long-term debt may include provisions that allow BHE or its subsidiaries to redeem such debt in whole or in part at any time. These provisions generally include make-whole premiums.

As of September 30, 2015, the Company's total net liquidity was as follows (in millions):

	BHE	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	AltaLink	Other	Total
Cash and cash equivalents	$ 478	$ 47	$ 246	$ 537	$ 5	$ 9	$ 329	$ 1,651
Credit facilities[1]	2,000	1,200	609	650	279	976	988	6,702
Less:								
Short-term debt	—	—	—	—	(207)	(227)	(506)	(940)
Tax-exempt bond support and letters of credit	(51)	(160)	(195)	—	—	(4)	—	(410)
Net credit facilities	1,949	1,040	414	650	72	745	482	5,352
Total net liquidity	$ 2,427	$ 1,087	$ 660	$ 1,187	$ 77	$ 754	$ 811	$ 7,003
Credit facilities:								
Maturity dates	2017	2017, 2018	2016, 2018	2018	2020	2016, 2019	2015, 2016, 2018	

(1) Includes the drawn uncommitted credit facilities totaling $52 million at Northern Powergrid.

Operating Activities

Net cash flows from operating activities for the nine-month periods ended September 30, 2015 and 2014 were $5.9 billion and $4.3 billion, respectively. Higher income tax receipts of $1.0 billion, improved operating results, including AltaLink, and other changes in working capital were partially offset by higher interest payments of $143 million.

In December 2014, the Tax Increase Prevention Act of 2014 (the "Act") was signed into law, extending the 50% bonus depreciation for qualifying property purchased and placed in-service before January 1, 2015 and before January 1, 2016 for certain longer-lived assets. Production tax credits were extended for wind power and other forms of non-solar renewable energy projects that begin construction before the end of 2014. As a result of the Act, the Company's cash flows from operations have benefited in 2015 due to bonus depreciation on qualifying assets placed in-service and for production tax credits earned on qualifying projects. The timing of the Company's income tax cash flows from period to period can be significantly affected by the changes in the tax law and the estimated federal income tax payment methods and assumptions for each payment date.

Investing Activities

Net cash flows from investing activities for the nine-month periods ended September 30, 2015 and 2014 were $(4.4) billion and $(4.2) billion, respectively. The change was primarily due to higher capital expenditures, including AltaLink, and changes in restricted cash and investments, partially offset by higher acquisitions totaling $246 million in 2014 compared to $157 million in 2015.

Financing Activities

Net cash flows from financing activities for the nine-month period ended September 30, 2015 was $(428) million. Uses of cash totaled $1.9 billion and consisted mainly of repayment of BHE junior subordinated debentures of $600 million, repayments of subsidiary debt totaling $712 million, net repayments of short-term debt of $473 million and repurchases of common stock totaling $36 million. Sources of cash totaled $1.5 billion related to proceeds from subsidiary debt issuances.

In October 2015, MidAmerican Energy issued $200 million of its 3.50% First Mortgage Bonds due October 2024 and $450 million of its 4.25% First Mortgage Bonds due May 2046. The net proceeds will be used for the repayment of $426 million of long-term debt maturing December 31, 2015, and for general corporate purposes.

In September 2015, TX Jumbo Road Wind, LLC issued a $230 million Term Loan due September 2025. The Term Loan has an underlying variable interest rate based on LIBOR plus a fixed credit spread with a one-time increase during the term of the loan. The Company has entered into interest rate swaps that fix the underlying interest rate on 100% of the outstanding debt.

In June 2015, PacifiCorp issued $250 million of its 3.35% First Mortgage Bonds due July 2025. The net proceeds were used to fund capital expenditures and for general corporate purposes, including retirement of short-term debt.

In June 2015, ALP issued C$350 million of its 4.09% Series 2015-1 Medium-Term Notes due June 2045. The net proceeds were used to repay short-term debt.

In April 2015, Northern Powergrid (Yorkshire) plc issued £150 million of its 2.50% Bonds due April 2025. The net proceeds were used for general corporate purposes, including the repayment of short-term debt.

In March 2015, Solar Star Funding, LLC issued $325 million of its 3.95% Series B Senior Secured Notes. The principal of the notes amortizes beginning June 2016 with a final maturity in June 2035. The net proceeds were used to fund the repayment or reimbursement of amounts provided by BHE for the costs related to the development, construction and financing of a combined 586-megawatt solar project in California (the "Solar Star Projects").

In March 2015, AltaLink Investments, L.P. issued C$200 million of its 2.244% Series 15-1 Senior Bonds due March 2022. The net proceeds were used to repay short-term debt, provide equity to ALP and for general corporate purposes.

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 and consisted of proceeds from subsidiary debt issuances of $1.3 billion and net proceeds from short-term debt of $367 million. Uses of cash totaled $1.5 billion and consisted mainly of repayments of BHE senior debt and junior subordinated debentures of $550 million and repayments of subsidiary debt of $884 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. Expenditures for certain assets may ultimately include acquisitions of existing assets.

The Company's historical and forecast 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,		Annual Forecast
	2014	2015	2015
Capital expenditures by business:			
PacifiCorp	$ 777	$ 640	$ 919
MidAmerican Funding	968	880	1,445
NV Energy	264	367	567
Northern Powergrid	479	535	693
BHE Pipeline Group	162	155	255
BHE Transmission	—	735	889
BHE Renewables	1,391	923	1,015
HomeServices	12	8	20
BHE and Other	7	8	11
Total	$ 4,060	$ 4,251	$ 5,814
Capital expenditures by type:			
Solar generation	$ 1,156	$ 729	$ 793
Wind generation	808	804	1,030
Electric transmission	302	725	931
Environmental	201	97	153
Other development projects	50	44	68
Electric distribution and other operating	1,543	1,852	2,839
Total	$ 4,060	$ 4,251	$ 5,814

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

- Solar generation includes the following:
  - Construction of the Topaz Project totaling $49 million and $443 million for the nine-month periods ended September 30, 2015 and 2014, respectively. Final completion under the engineering, procurement and construction agreement occurred February 28, 2015, and project completion was achieved under the financing documents on March 30, 2015.
  - Construction of the Solar Star Projects totaling $641 million and $713 million for the nine-month periods ended September 30, 2015 and 2014, respectively. Subsidiaries of Solar Star Funding anticipate costs for the Solar Star Projects will total an additional $57 million for 2015. Facility substantial completion under the engineering, procurement and construction agreements occurred in July 2015 for the Solar Star Projects, and both projects declared July 1, 2015 as the commercial operation date in accordance with the power purchase agreements.

- Wind generation includes the following:
  - Construction of wind-powered generating facilities at MidAmerican Energy totaling $601 million and $593 million for the nine-month periods ended September 30, 2015 and 2014, respectively. MidAmerican Energy anticipates costs for wind-powered generating facilities will total an additional $209 million for 2015. MidAmerican Energy is constructing an additional 657 MW (nominal ratings) of wind-powered generating facilities expected to be placed in-service in 2015, and 551 MW (nominal ratings) approved by the IUB in August 2015 that are expected to be placed in-service in 2016.
  - Construction of wind-powered generating facilities at BHE Renewables totaling $201 million and $214 million for the nine-month periods ended September 30, 2015 and 2014, respectively. The Jumbo Road Project with a total capacity of 300 MW achieved commercial operation in April 2015. In addition, BHE Renewables acquired for cash consideration totaling $111 million certain assets that will facilitate the development of up to 472 MW of wind-powered generating facilities in Nebraska and Kansas. BHE Renewables anticipates costs for wind-powered generating facilities will total an additional $31 million for 2015.
- Electric transmission includes investments for ALP's directly assigned projects from the AESO, PacifiCorp's costs primarily associated with the Energy Gateway Transmission Expansion Program and MidAmerican Energy's MVPs approved by the MISO for the construction of 245 miles of 345 kV transmission line located in Iowa and Illinois.
- Environmental includes the installation of new or the replacement of existing emissions control equipment at certain generating facilities at the Utilities, including installation or upgrade of selective catalytic reduction control systems and low nitrogen oxide burners to reduce nitrogen oxides, particulate matter control systems, sulfur dioxide emissions control systems and mercury emissions control systems, as well as expenditures for the management of coal combustion residuals.
- Electric distribution and other operating includes ongoing distribution systems infrastructure needed at the Utilities and Northern Powergrid and investments in routine expenditures for transmission, generation and other infrastructure needed to serve existing and expected demand.

MidAmerican Energy Wind

In April 2015, MidAmerican Energy filed with the IUB an application for ratemaking principles related to the construction of up to 552 MW (nominal ratings) of additional wind-powered generating facilities expected to be placed in-service by the end of 2016. In June 2015, MidAmerican Energy and the Iowa Office of Consumer Advocate ("OCA") entered into a settlement agreement relating to the proposal. The settlement agreement established a cost cap of $903 million, including AFUDC, and provides for a fixed rate of return on equity of 11.35% over the proposed 30-year useful lives of those facilities in any future Iowa rate proceeding. In August 2015, the IUB approved the settlement agreement except for a reduction of the cost cap to $889 million, including AFUDC, to which MidAmerican Energy and the OCA agreed. 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.

Other Renewable Investments

The Company has entered into renewable tax equity investments that require equity contributions of approximately $170 million in 2015 and $480 million in 2016.

PacifiCorp and the California ISO Memorandum of Understanding

In April 2015, PacifiCorp and the California Independent System Operator Corporation ("California ISO") entered into a non-binding memorandum of understanding to explore the feasibility, costs and benefits of PacifiCorp joining a regional ISO as a participating transmission owner if the California ISO becomes a regional ISO by modifying its governance structure and expanding its balancing authority area. A comprehensive benefits study was completed and results were publicly announced in October 2015, along with an extension of the non-binding memorandum of understanding. The benefits study demonstrated gross benefits for customers exist, warranting further exploration and analysis of integration. PacifiCorp and the California ISO will initiate a stakeholder input and review process. If PacifiCorp decides to become a participating transmission owner in the regional ISO, it will seek necessary regulatory approvals, including from its state regulatory commissions and the FERC. PacifiCorp and the California ISO launched the regional energy imbalance market ("EIM") in November 2014, which allows PacifiCorp to participate in the California ISO's real-time energy markets to most cost-effectively manage short-term fluctuations in energy supply and demand. Joining the regional ISO would extend that participation by PacifiCorp into the day-ahead energy market operated by the California ISO, in addition to unified planning and operation of PacifiCorp's transmission network.

Nevada Utilities Energy Imbalance Market

The Nevada Utilities had previously announced plans to join the EIM in October 2015. The EIM is expected to reduce costs to serve customers through more efficient dispatch of a larger and more diverse pool of generation resources, more effectively integrate renewables and enhance reliability through improved situational awareness and responsiveness. In July 2015, following the issuance of an order by the FERC and in conjunction with the California ISO's announcement of a supplemental stakeholder process, the California ISO and the Nevada Utilities announced a delay in the EIM entrance date. In October 2015, the California ISO and the Nevada Utilities filed its Readiness Certification with the FERC for its participation in the EIM; however the Nevada Utilities are awaiting the FERC's approval before participating in the EIM.

NV Energy Joint Dispatch

Nevada Power and Sierra Pacific are currently parties to an Interim Joint Dispatch Agreement ("Interim JDA") which outlines the joint dispatch of their combined power supply resources utilizing ON Line. In March 2015, Nevada Power and Sierra Pacific filed an application with the PUCN seeking approval of an indefinite Joint Dispatch Agreement ("JDA"). The JDA is intended to replace the currently effective Interim JDA, which terminates on December 31, 2015. Joint dispatch transactions addressed by the proposed JDA include real-time, hourly and daily transactions. The JDA also explicitly governs joint dispatch transactions between the Nevada Utilities and the California ISO utilizing the California ISO's EIM.

The primary differences between the Interim JDA and the JDA relate to EIM transactions with the California ISO. The JDA establishes Nevada Power as the EIM scheduling coordinator for the Nevada Utilities and recognizes that the joint dispatch costs and benefits associated with EIM transactions will be governed by the accounting protocols and allocations set forth in the JDA, which are unchanged from those currently in effect under the Interim JDA. In July 2015, the PUCN approved the JDA with minor modifications, and established December 31, 2019 as the termination date for the agreement. In September 2015, the JDA was approved by the FERC.

Contractual Obligations

As of September 30, 2015, 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, 2014 other than the 2015 debt issuances and the renewable tax equity investments previously discussed and the 2015 commitments discussed in Note 13 in Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q.

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, 2014, and new regulatory matters occurring in 2015.

PacifiCorp

Utah Mine Disposition

In December 2014, PacifiCorp filed applications with the UPSC, the OPUC, the WPSC and the IPUC seeking certain approvals, prudence determinations and accounting orders to close its Deer Creek mining operations, sell certain Utah mining assets, enter into a replacement coal supply agreement, amend an existing coal supply agreement, withdraw from the United Mine Workers of America ("UMWA") 1974 Pension Plan and settle PacifiCorp's other postretirement benefit obligation for UMWA participants (collectively, the "Utah Mine Disposition").

In April 2015, PacifiCorp filed all-party settlement stipulations with the UPSC and the WPSC finding that the decision to enter into the Utah Mine Disposition transaction is prudent and in the public interest and recommending the appropriate treatment for accounting and ratemaking purposes. The UPSC approved the stipulation in April 2015 and the WPSC approved the stipulation in May 2015. The IPUC also issued an order in May 2015, approving the Utah Mine Disposition and ruling that the decision to enter into the transaction was prudent and in the public interest. The IPUC's order established the accounting treatment necessary to implement the transaction while deferring any incremental ratemaking treatment to the next general rate case.

In May 2015, the OPUC issued its final order in the Utah Mine Disposition transaction proceeding, concluding that the transaction produces net benefits for customers and is in the public interest. In accordance with the OPUC order, PacifiCorp implemented two tariffs that reflect an overall annual rate increase of $3 million effective June 2015.

Utah

In March 2015, PacifiCorp filed its annual Energy Balancing Account with the UPSC requesting recovery of $31 million in deferred net power costs for the period January 1, 2014 through December 31, 2014. In September 2015, a settlement agreement was filed with the UPSC in which the parties agreed to recovery of $30 million. In October 2015, the UPSC approved the settlement agreement with the new rates effective November 2015.

In March 2015, PacifiCorp filed its annual renewable energy credit ("REC") balancing account application with the UPSC requesting recovery of $6 million over a two-year period. In May 2015, the UPSC approved the new rates effective June 2015 on an interim basis until a final order is issued by the UPSC. In September 2015, the UPSC issued a final order approving the interim rates as final.

Oregon

In April 2015, PacifiCorp made its initial filing for the annual Transition Adjustment Mechanism with the OPUC for an annual increase of $12 million, or an average price increase of 1%, based on forecasted net power costs for calendar year 2016. The filing will be subject to updates throughout the year. In October 2015, the OPUC issued a preliminary order approving PacifiCorp's request, subject to updates in November 2015. New rates will be effective January 2016.

Wyoming

In March 2015, PacifiCorp filed a general rate case with the WPSC requesting an annual increase of $32 million, or an average price increase of 5%, effective January 2016. The filing includes a proposal to implement a modified Energy Cost Adjustment Mechanism ("ECAM") to replace the current ECAM, which sunsets for new deferrals December 2015. In June 2015, PacifiCorp filed a net power cost update that reduced the requested increase to $30 million. In September 2015, PacifiCorp filed rebuttal testimony reducing the requested increase to $27 million, or an average price increase of 4%. Hearings were held in October and early November of 2015.

In March 2015, PacifiCorp filed its annual ECAM and Renewable Energy Credit and Sulfur Dioxide Revenue Adjustment Mechanism ("RRA") applications with the WPSC. The ECAM filing requests approval to recover $8 million in deferred net power costs for the period January 1, 2014 through December 31, 2014, and the RRA application requests approval to refund $1 million to customers. In May 2015, the WPSC approved the ECAM and RRA rates effective May 2015 on an interim basis. In September 2015, the WPSC approved a stipulation in which the parties agreed to allow the interim rates that were effective in May 2015 to become final.

Washington

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%. In November 2014, PacifiCorp filed rebuttal testimony that increased the request to $32 million, or an average price increase of 10%, primarily as a result of updated net power costs. In March 2015, the WUTC issued a final order in the proceeding approving an overall annual increase of $10 million, or an average price increase of 3%, effective March 2015. In April 2015, PacifiCorp filed a petition for judicial review of certain findings of the WUTC's March 2015 order.

In the March 2015 general rate case order described above, the WUTC initiated a second phase of the proceeding to implement a Power Cost Adjustment Mechanism ("PCAM") under which a portion of the difference between base net power costs set during a general rate case and actual net power costs would be deferred and reflected in future rates. In May 2015, the WUTC approved an all-party stipulation in which the parties agreed to the implementation of a PCAM. The PCAM applies a $4 million dead band for positive or negative net power cost variances. For net power cost variances between $4 million and $10 million, the PCAM reflects asymmetrical sharing bands in which amounts to be recovered from customers will be allocated 50% to customers and 50% to PacifiCorp, and amounts to be credited to customers will be allocated 75% to customers and 25% to PacifiCorp. Positive or negative net power cost variances in excess of $10 million will be allocated 90% to customers and 10% to PacifiCorp. PacifiCorp will make its first annual PCAM filing in June 2016 to cover net power costs for the period April 1, 2015 through December 31, 2015. The PCAM will convert to a calendar year basis beginning in 2016.

Idaho

In February 2015, PacifiCorp filed its annual ECAM application with the IPUC requesting recovery of $17 million, consisting primarily of $10 million for deferred net power costs and $6 million for the difference between REC revenues included in base rates and actual REC revenues. In March 2015, the IPUC approved recovery of $16 million effective April 2015.

In May 2015, PacifiCorp filed an application with the IPUC requesting approval to modify the ECAM, update base net power costs and increase rates by $10 million, effective January 2016. The requested increase included $7 million for the difference between REC revenues included in base rates and actual REC revenues, and $3 million as a result of updating base net power costs. In October 2015, PacifiCorp filed a settlement agreement with the IPUC in which the parties agreed to the requested increase in rates, effective January 2016. If the settlement agreement is approved, the ECAM will be modified to include production tax credits and exclude sulfur dioxide revenues. The settlement agreement allows another update to base net power costs in rates to be effective January 2017 and also specifies that January 2018 would be the earliest effective date that PacifiCorp could seek an increase to base rates through a general rate case.

NV Energy

In July 2015, Nevada Power filed an amendment to its Emissions Reduction and Capacity Replacement Plan ("ERCR Plan") with the PUCN. In September 2015, the PUCN approved the filed amendment requesting two renewable power purchase agreements with 100-MW solar photovoltaic generating facilities related to the replacement of coal plants. Each of these agreements were entered into by issuing requests for proposals for the procurement of energy through the competitive solicitation process that was set forth in Nevada Power's ERCR Plan in compliance with Senate Bill No. 123 ("SB 123"). In June 2015, the Nevada State Legislature passed Assembly Bill No. 498, which modified the capacity replacement components of SB 123. As a result, Nevada Power will not proceed with issuance of a third 100-MW request for proposal for renewable energy until such time as the PUCN determines Nevada Power has satisfactorily demonstrated a need for such electric generating capacity.

Northern Powergrid

In March 2015, Northern Powergrid sought permission from the Competition and Markets Authority ("CMA") to appeal against the license modifications that give effect to the RIIO-ED1 price control. The appeal relates to three specific areas:

1. Ofgem's decision to demand further cost savings in relation to smart grid technology over and above the ones captured by its original benchmarking exercise;
2. Ofgem's assessment of the variation in wage rates across the country; and
3. Ofgem's projections for labor cost increases.

Permission to appeal was granted by the CMA in March 2015. British Gas Trading Limited (an electricity supplier) was granted permission to appeal the price control, with a view to reduce the revenue available to all slow-tracked Distribution Network Operators.

In September 2015, the CMA announced it upheld Northern Powergrid's appeal on cost savings in relation to smart grid technology concluding that Ofgem's decision was not based on robust evidence. The CMA has therefore increased Northern Powergrid's cost allowance for the period April 2015 to March 2023 by £32 million in 2012/13 prices. The CMA determined Ofgem's decision on the assessment of the variation in wage rates across the country and their projections for labor cost increases fell within the margin of discretion that is available to Ofgem.

In September 2015, the CMA also announced it upheld one part of one ground of the British Gas appeal. As a result the CMA has reduced the value of an incentive scheme for all slow-tracked Distribution Network Operators that reduces Northern Powergrid's revenues by £14 million in 2012/13 prices for the period April 2015 to March 2023.

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 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. In June 2015, the United States Court of Appeals for the District of Columbia denied both appeals.

ALP

In November 2014, ALP filed a general tariff application asking the AUC to approve revenue requirements of C$811 million for 2015 and C$1.0 billion for 2016, primarily due to continued investment in capital projects as directed by the AESO. In January 2015, the AUC issued its decision approving ALP's 2015 interim tariff application, as filed, thereby authorizing ALP to invoice the AESO C$61 million per month commencing January 1, 2015.

In March 2015, the AUC issued its decision regarding cost of capital matters applicable to all electricity and natural gas utilities under its jurisdiction, including ALP. In its decision, which was retroactively applied to January 1, 2013, the AUC decreased the generic rate of return on common equity applicable to all utilities to 8.30% from the previously approved placeholder rate of 8.75% and decreased ALP's common equity ratio from 37% to 36% for the years 2013, 2014 and 2015. The approved common equity ratio and generic rate of return on common equity will remain in effect on an interim basis for 2016 and beyond, until changed by the AUC. ALP and other utilities had applied to the Alberta Court of Appeal for Leave to appeal this decision. In a unanimous decision, the Alberta Court of Appeal for Leave dismissed the appeal in September 2015 concluding that the AUC's decision in the Utility Asset Disposition matter was not unreasonable. In April 2015, the AUC opened a new generic cost of capital proceeding for 2016 and 2017. In October 2015, the AUC approved a request by Alberta's utilities, including AltaLink, to initiate a negotiated settlement.. The Alberta Utilities met with interveners in October 2015, but were unable to reach a settlement.

In June 2015, ALP amended the general tariff application to propose additional transmission tariff relief measures for customers and modifications to its capital structure. In October 2015, an update to this amended application was filed. The October 2015 update includes timing benefits to customers by discontinuing (i) the use of construction work-in-progress in-rate base effective January 1, 2015, and refunding related amounts received as part of the 2011 to 2014 transmission tariffs and (ii) the collection of future income taxes in current tariff revenue, effective January 1, 2016, and refunding related amounts received as part of the transmission tariffs for 2015 and prior years. ALP's October 2015 update requests the AUC to approve an increase of 2% in ALP's common equity ratio. In addition, the October 2015 update requests the AUC to approve revenue requirements of C$672 million for 2015 and C$703 million for 2016. The AUC has scheduled a hearing on the amended and updated general tariff application in December 2015.

In ALP's amended general tariff application, updated October 2015, ALP forecasted capital expenditures to be C$961 million for 2015 and C$538 million for 2016. ALP based its direct assign capital forecast, which comprises more than 80% of its total capital expenditures, on the most recent long-range capital plan released by the AESO in January 2014, using its risk-adjusted capital forecasting model accepted by the AUC in its decision on ALP's previous general tariff application. ALP's actual capital program may vary from ALP's regulatory filings, depending on the timing of regulatory approvals, directions from the AESO, and other factors beyond ALP's control.

In December 2014, ALP filed its 2012-2013 Deferral Accounts Reconciliation Application seeking the AUC's approval to collect C$30 million from the AESO for previously uncollected deferral account balances. In addition, ALP is seeking approval of nearly C$1.7 billion of direct assign capital additions, included as part of the direct assigned capital deferral account filing. The AUC has scheduled a hearing for this application in November 2015.

In its November 2013 decision pertaining to ALP's 2013-2014 general tariff application, the AUC directed ALP to re-forecast the capital project expenditures for 2013 and 2014 Engineering, Procurement and Construction Management ("EPCM") services to reflect a two times labor multiplier and other approved mark-ups. While the AUC has not disallowed the new EPCM rates that ALP negotiated, there is a risk that, in a future direct assigned capital deferral account decision, the AUC may disallow a portion of the costs ALP has incurred for EPCM services in connection with capital projects executed under these relationship agreements. ALP has appealed this decision, which is scheduled to be heard in February 2016. ALP has requested approval of the capital project expenditures, including the new competitively bid EPCM rates, in its 2012-2013 direct assigned capital deferral account filing.

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 forecast 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, 2014.

Clean Air Act Regulations

National Ambient Air Quality Standards

The Sierra Club filed a lawsuit against the EPA in August 2013 with respect to the one-hour sulfur dioxide standards and its failure to make certain attainment designations in a timely manner. In March 2015, the United States District Court for the Northern District of California ("Northern District of California") accepted as an enforceable order an agreement between the EPA and Sierra Club to resolve litigation concerning the deadline for completing the designations. The Northern District of California's order directed the EPA to complete designations in three phases: the first phase by July 2, 2016; the second phase by December 31, 2017; and the final phase by December 31, 2020. The first phase of the designations require the EPA to designate two groups of areas: 1) areas that have newly monitored violations of the 2020 sulfur dioxide standard; and 2) areas that contain any stationary source that, according to the EPA's data, either emitted more than 16,000 tons of sulfur dioxide in 2012 or emitted more than 2,600 tons of sulfur dioxide and had an emission rate of at least 0.45 lbs/sulfur dioxide per million British thermal unit in 2012 and, as of March 2, 2015, had not been announced for retirement. MidAmerican Energy's George Neal Unit 4 and the Ottumwa Generating Station (in which MidAmerican Energy has a majority ownership interest, but does not operate), are included as units subject to the first phase of the designations, having emitted more than 2,600 tons of sulfur dioxide and having an emission rate of at least 0.45 lbs/sulfur dioxide per million British thermal unit in 2012. States may submit to the EPA updated recommendations and supporting information for the EPA to consider in making its determinations. Iowa has assembled technical support documents demonstrating that all facilities affected by the first phase of designations have attained the standard, but has not yet submitted the information to the EPA. The EPA intends to promulgate final sulfur dioxide area designations no later than July 2, 2016.

In October 2015, the EPA released revised ambient air quality standards for ground level ozone, lowering the standard from 75 parts per billion to 70 parts per billion. Under the Clean Air Act, the EPA is required to finalize a list of areas that are in "nonattainment" with the new standard by October 1, 2017. Given the level at which the standard was set in conjunction with retirements and the installation of controls, the new standard is not expected to have a significant impact on the Company.

Mercury and Air Toxics Standards

Numerous lawsuits have been filed in the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") challenging the Mercury and Air Toxics Standards ("MATS"). In April 2014, the D.C. Circuit upheld the MATS requirements. In November 2014, the United States Supreme Court agreed to hear the MATS appeal on the limited issue of whether the EPA unreasonably refused to consider costs in determining whether it is appropriate to regulate hazardous air pollutants emitted by electric utilities. Oral argument in the case was held before the United States Supreme Court in March 2015, and a decision was issued by the United States Supreme Court in June 2015, which reversed and remanded the MATS rule to the D.C. Circuit for further action. The United States Supreme Court held that the EPA had acted unreasonably when it deemed cost irrelevant to the decision to regulate generating facilities, and that cost, including costs of compliance, must be considered before deciding whether regulation is necessary and appropriate. The United States Supreme Court's decision did not vacate or stay implementation of the MATS rule and until the D.C. Circuit takes further action, the Company continues to have a legal obligation under the MATS rule and its permits issued by the states in which it operates to comply with the MATS rule, including operating all emissions controls or otherwise complying with the MATS requirements, such as PacifiCorp idling the Carbon coal-fueled generating facility ("Carbon Facility") and MidAmerican Energy retiring the Walter Scott, Jr. Energy Center Units 1 and 2 coal-fueled generating facilities and ceasing the utilization of coal at the Riverside Generating Station in April 2015. Refer to the Regional Haze section below for additional requirements regarding the Carbon Facility.

Regional Haze

The state of Utah issued a regional haze State Implementation Plan ("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 best available retrofit technology ("BART") determinations for the 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 on jurisdictional grounds. 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. The additional BART analysis and revised regional haze SIP was submitted in June 2015 to the EPA for review and proposed action after a public comment period. The revised regional haze SIP includes a state-enforceable requirement to cease operation of the Carbon Facility by August 15, 2015, and PacifiCorp has begun decommissioning activities. This requirement is independent of the requirements of the MATS rule as discussed above. As a result of a suit brought to enforce the EPA deadlines for taking action on the Utah SIP, the EPA is expected to review and take final action on the SIP in March 2016 pursuant to a proposed consent decree. It is unknown how the EPA's decision regarding the Utah SIP may impact PacifiCorp's obligations under the regional haze requirements.

The state of Arizona issued a regional haze SIP requiring, among other things, the installation of sulfur dioxide, nitrogen oxides and particulate matter controls on Cholla Unit 4. The EPA approved in part, and disapproved in part, the Arizona SIP and issued a Federal Implementation Plan ("FIP") for the disapproved portions requiring selective catalytic reduction controls on Cholla Unit 4. PacifiCorp filed an appeal in the United States Court of Appeals for the Ninth Circuit ("Ninth Circuit") regarding the FIP as it relates to Cholla Unit 4, and the Arizona Department of Environmental Quality and other affected Arizona utilities filed separate appeals of the FIP as it relates to their interests. The Ninth Circuit issued an order in February 2015, holding the matter in abeyance relating to PacifiCorp and Arizona Public Service Company as they work with state and federal agencies on an alternate compliance approach for Cholla Unit 4. In January 2015, Arizona Public Service Company submitted the permit applications and studies required to amend the Title V permit, and subsequently the Arizona SIP to convert Cholla Unit 4 to a natural gas-fueled unit in 2025. The Arizona Department of Environmental Quality prepared a draft permit and a revision to the Arizona regional haze SIP, held two public hearings in July 2015 and, after considering the comments received during the public comment period that closed on July 14, 2015, submitted the final proposals to the EPA for review, public comment and final action.

Climate Change

GHG Performance Standards

Under the Clean Air Act, the EPA may establish emissions standards that reflect the degree of emissions reductions achievable through the best technology that has been demonstrated, taking into consideration the cost of achieving those reductions and any non-air quality health and environmental impact and energy requirements. The EPA entered into a settlement agreement with a number of parties, including certain state governments and environmental groups, in December 2010 to promulgate emissions standards covering GHG. In April 2012, the EPA proposed new source performance standards for new fossil-fueled generating facilities that would limit emissions of carbon dioxide to 1,000 pounds per MWh. As part of his Climate Action Plan, President Obama announced a national climate change strategy and issued a presidential memorandum requiring the EPA to issue a re-proposed GHG new source performance standard for fossil-fueled generating facilities by September 2013. The September 2013 GHG new source performance standards released by the EPA set different standards for coal-fueled and natural gas-fueled generating facilities. The proposed standard for natural gas-fueled generating facilities considered the size of the unit and the electricity sent to the grid from the unit. The proposed standards were published in the Federal Register January 8, 2014, and the public comment period closed in May 2014. On August 3, 2015, the EPA issued the final new source performance standards, establishing a standard of 1,000 pounds of carbon dioxide per MWh for large natural gas-fueled generating facilities and 1,400 pounds of carbon dioxide per MWh for new coal-fueled generating facilities with the "Best System of Emission Reduction" for coal-fueled generating facilities reflecting highly efficient supercritical pulverized coal facilities with partial carbon capture and sequestration or integrated gasification combined-cycle units that are co-fired with natural gas or pre-combustion slipstream capture of carbon dioxide. Any new fossil-fueled generating facilities constructed by the Company will be required to meet the GHG new source performance standards.

Clean Power Plan

In June 2014, the EPA released proposed regulations to address GHG 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 this proposal, states could have utilized 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 was expected to reduce carbon dioxide emissions in the power sector to 30% below 2005 levels by 2030. The final Clean Power Plan was released August 3, 2015 and changed the methodology upon which the Best System of Emission Reduction is based to include: (a) heat rate improvements; (b) increased utilization of existing combined-cycle natural gas-fueled generating facilities; and (c) increased deployment of new and incremental non-carbon generation placed in-service after 2012. The EPA also changed the compliance period to begin in 2022, with three interim periods of compliance and with the final goal to be achieved by 2030. Based on changes to the state emission reduction targets, which are now all between 771 pounds per MWh and 1,305 pounds per MWh, the Clean Power Plan, when fully implemented, is expected to reduce carbon dioxide emissions in the power sector to 32% below 2005 levels by 2030. The EPA also released on August 3, 2015, a draft federal plan as an option or backstop for states to utilize in the event they do not submit approvable state plans. The draft federal plan is expected to be open for a 90-day public comment period after publication in the Federal Register. States are required to submit initial implementation plans by September 2016, and may request an extension to September 2018. The full impacts of the final rule or the federal plan on PacifiCorp, MidAmerican Energy, Nevada Power, Sierra Pacific and BHE Renewables cannot be determined until the states develop their implementation plans or the federal plan is finalized. 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.

The GHG rules and the Company's compliance requirements are subject to potential outcomes from proceedings and litigation challenging the rules.

Renewable Portfolio Standards

The California Renewable Portfolio Standards ("RPS") required all California retail sellers to procure an average of 20% of retail load from renewable resources by December 31, 2013, 25% by December 31, 2016 and 33% by December 31, 2020. In October 2015, California Senate Bill No. 350 was signed into law, which increased the current RPS requirement to 40% by December 31, 2024, 45% by December 31, 2027 and 50% by December 31, 2030. In December 2011, the CPUC adopted a decision confirming that multi-jurisdictional utilities, such as PacifiCorp, are not subject to the percentage limits within the three product content categories of RPS-eligible resources established by the legislation that have been imposed on other California retail sellers.

Coal Combustion Byproduct Disposal

In May 2010, the EPA released a proposed rule to regulate the management and disposal of coal combustion byproducts, presenting two alternatives to regulation under the Resource Conservation and Recovery Act ("RCRA"). The public comment period closed in November 2010. The final rule was released by the EPA on December 19, 2014, was published in the Federal Register on April 17, 2015 and was effective on October 19, 2015. The final rule regulates coal combustion byproducts as non-hazardous waste under RCRA Subtitle D and establishes minimum nationwide standards for the disposal of coal combustion residuals. Under the final rule, surface impoundments and landfills utilized for coal combustion byproducts may need to be closed unless they can meet the more stringent regulatory requirements.

At the time the rule was published in April 2015, PacifiCorp operated 18 surface impoundments and seven landfills that contained coal combustion byproducts. Prior to the effective date in October 2015, nine surface impoundments and three landfills were either closed or repurposed to no longer receive coal combustion byproducts and hence are not subject to the final rule. MidAmerican Energy owns or operates seven surface impoundments and four landfills that contain coal combustion byproducts. The Nevada Utilities operate ten evaporative surface impoundments and two landfills that contain coal combustion byproducts. Refer to Note 10 for discussion of the impacts on asset retirement obligations as a result of the final rule.

In September 2015, the EPA released final effluent limitation guidelines for steam electric generating facilities which, among other things, regulate the discharge of bottom ash transport water, fly ash transport water, combustion residuals leachate and non-metal cleaning wastes. Permitting authorities are required to include the new limits in each facility's discharge permit upon renewal. These limits must be met "as soon as possible" beginning November 1, 2018 and implementation cannot be delayed past December 31, 2023. The final rule was published in the Federal Register on November 3, 2015 and will be effective on January 4, 2016. With minor exceptions, many of the compliance requirements associated with the effluent limitation guidelines are addressed by PacifiCorp and MidAmerican Energy under the coal combustion residuals rule. None of the new requirements impact the Nevada Utilities.

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, 2015, 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, 2015, the Company would have been required to post $586 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 11 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.

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, 2014. There have been no significant changes in the Company's assumptions regarding critical accounting estimates since December 31, 2014.

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, 2014. The Company's exposure to market risk and its management of such risk has not changed materially since December 31, 2014. Refer to Note 11 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, 2015.

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, 2015 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, 2014.

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.

On November 4, 2015, Bridger Coal Company, a coal mining joint venture that is two-thirds owned and operated by a subsidiary of PacifiCorp, received an imminent danger order under section 107(a) of the Federal Mine Safety and Health Act of 1977 at its underground mine located near Rock Springs, Wyoming. On that same date, Bridger Coal Company completed actions to abate the concerns, and the Federal Mine Safety and Health Administration terminated the section 107(a) order.

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 6, 2015

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

EXHIBIT INDEX

Exhibit No.	Description
4.1	First Supplemental Indenture, dated as of March 12, 2015, between Solar Star Funding, LLC, as Issuer, and Wells Fargo Bank, National Association, as Trustee, relating to the $325,000,000 in principal amounts of the 3.95% Series B Senior Secured Notes Due 2035 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2015).
4.2	Series 15-1 Supplemental Indenture, dated March 6, 2015, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada, relating to C$200,000,000 in principal amounts of the 2.244% Series 15-1 Senior Bonds due 2022 (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2015).
4.3	Trust Deed, dated as of April 1, 2015, among Northern Powergrid (Yorkshire) plc and HSBC Corporate Trustee Company (UK) Limited, relating to £150,000,000 in principal amount of the 2.50% Bonds due 2025 (incorporated by reference to Exhibit 4.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2015).
4.4	Twenty-Eighth Supplemental Indenture, dated as of June 1, 2015, 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 June 19, 2015).
4.5	Twentieth Supplemental Indenture, dated June 30, 2015, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada, relating to C$350,000,000 in principal amounts of the 4.09% Series 2015-1 Medium-Term Notes due 2045 (incorporated by reference to Exhibit 4.5 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2015).
4.6	Amendment No. 1 to the Second Supplemental Indenture, dated as of October 15, 2015, 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 October 15, 2015).
4.7	Third Supplemental Indenture, dated as of October 15, 2015, 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 October 15, 2015).
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, 2015, 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 6, 2015

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, 2015 and 2014, as indicated in our report dated November 6, 2015; 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, 2015, 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 6, 2015

/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 6, 2015

/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, 2015 (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 6, 2015

/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, 2015 (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 6, 2015

/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, 2015 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. Mines that are closed or idled are not included in the information below if no reportable events occurred at those locations during the three-month period ended September 30, 2015. There were no mining-related fatalities during the three-month period ended September 30, 2015. 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, 2015.

	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(7)	—	—	—	—	—	$ —	—	—	1
Bridger (surface)	3	—	—	—	—	213	6	3	—
Bridger (underground)	9	—	—	—	—	40	2	2	5
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 six contests of proposed penalties under Subpart C and two contests of citations or orders under Subpart B 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.

(7) The Deer Creek mine is currently idled and closure activities have begun.