PACIFICORP

Pacific Power |
Rocky Mountain Power
825 NE Multnomah, Suite 1900
Portland, Oregon 97232

March 16, 2017

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Secretary

RE: Form 10-K

Dear Commissioner:

Enclosed is a copy of PacifiCorp's most recent annual report on Form 10-K for the period ended December 31, 2016 as filed with the United States Securities and Exchange Commission pursuant to the requirement of the Securities Exchange Act of 1934.

Sincerely,

Christian Rad
External Reporting Manager

Enclosure

cc: Chris Parker – Utah Division of Public Utilities
Artie Powell – Utah Division of Public Utilities
Cheryl Murray – Utah Office of Consumer Services
Michele Beck – Utah Office of Consumer Services

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

FORM 10-K

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

For the fiscal year ended December 31, 2016

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**
001-05152	**PACIFICORP** **(An Oregon Corporation)** **825 N.E. Multnomah Street** **Portland, Oregon 97232** **888-221-7070**	**93-0246090**
333-90553	**MIDAMERICAN FUNDING, LLC** **(An Iowa Limited Liability Company)** **666 Grand Avenue, Suite 500** **Des Moines, Iowa 50309-2580** **515-242-4300**	**47-0819200**
333-15387	**MIDAMERICAN ENERGY COMPANY** **(An Iowa Corporation)** **666 Grand Avenue, Suite 500** **Des Moines, Iowa 50309-2580** **515-242-4300**	**42-1425214**
000-52378	**NEVADA POWER COMPANY** **(A Nevada Corporation)** **6226 West Sahara Avenue** **Las Vegas, Nevada 89146** **702-402-5000**	**88-0420104**
000-00508	**SIERRA PACIFIC POWER COMPANY** **(A Nevada Corporation)** **6100 Neil Road** **Reno, Nevada 89511** **775-834-4011**	**88-0044418**

Registrant	Securities registered pursuant to Section 12(b) of the Act:
BERKSHIRE HATHAWAY ENERGY COMPANY	None
PACIFICORP	None
MIDAMERICAN FUNDING, LLC	None
MIDAMERICAN ENERGY COMPANY	None
NEVADA POWER COMPANY	None
SIERRA PACIFIC POWER COMPANY	None

Registrant	Securities registered pursuant to Section 12(g) of the Act:
BERKSHIRE HATHAWAY ENERGY COMPANY	None
PACIFICORP	None
MIDAMERICAN FUNDING, LLC	None
MIDAMERICAN ENERGY COMPANY	None
NEVADA POWER COMPANY	Common Stock, $1.00 stated value
SIERRA PACIFIC POWER COMPANY	Common Stock, $3.75 par value

Registrant	Name of exchange on which registered:
BERKSHIRE HATHAWAY ENERGY COMPANY	None
PACIFICORP	None
MIDAMERICAN FUNDING, LLC	None
MIDAMERICAN ENERGY COMPANY	None
NEVADA POWER COMPANY	None
SIERRA PACIFIC POWER COMPANY	None

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

Registrant	Yes	No
BERKSHIRE HATHAWAY ENERGY COMPANY		X
PACIFICORP		X
MIDAMERICAN FUNDING, LLC		X
MIDAMERICAN ENERGY COMPANY	X	
NEVADA POWER COMPANY		X
SIERRA PACIFIC POWER COMPANY		X

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Registrant	Yes	No
BERKSHIRE HATHAWAY ENERGY COMPANY		X
PACIFICORP		X
MIDAMERICAN FUNDING, LLC	X	
MIDAMERICAN ENERGY COMPANY		X
NEVADA POWER COMPANY		X
SIERRA PACIFIC POWER COMPANY		X

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.

Registrant	Yes	No
BERKSHIRE HATHAWAY ENERGY COMPANY	X	
PACIFICORP	X	
MIDAMERICAN FUNDING, LLC		X
MIDAMERICAN ENERGY COMPANY	X	
NEVADA POWER COMPANY	X	
SIERRA PACIFIC POWER COMPANY	X	

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web sites, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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

Registrant	Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller reporting company
BERKSHIRE HATHAWAY ENERGY COMPANY			X	
PACIFICORP			X	
MIDAMERICAN FUNDING, LLC			X	
MIDAMERICAN ENERGY COMPANY			X	
NEVADA POWER COMPANY			X	
SIERRA PACIFIC POWER COMPANY			X	

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

All shares of outstanding common stock of Berkshire Hathaway Energy Company are privately held by a limited group of investors. As of February 17, 2017, 77,356,144 shares of common stock, no par value, were outstanding.

All shares of outstanding common stock of PacifiCorp are indirectly owned by Berkshire Hathaway Energy Company. As of February 17, 2017, 357,060,915 shares of common stock, no par value, were outstanding.

All of the member's equity of MidAmerican Funding, LLC is held by its parent company, Berkshire Hathaway Energy Company, as of February 17, 2017.

All shares of outstanding common stock of MidAmerican Energy Company are owned by its parent company, MHC Inc., which is a direct, wholly owned subsidiary of MidAmerican Funding, LLC. As of February 17, 2017, 70,980,203 shares of common stock, no par value, were outstanding.

All shares of outstanding common stock of Nevada Power Company are owned by its parent company, NV Energy, Inc., which is an indirect, wholly owned subsidiary of Berkshire Hathaway Energy Company. As of February 17, 2017, 1,000 shares of common stock, $1.00 stated value, were outstanding.

All shares of outstanding common stock of Sierra Pacific Power Company are owned by its parent company, NV Energy, Inc. As of February 17, 2017, 1,000 shares of common stock, $3.75 par value, were outstanding.

MidAmerican Funding, LLC, MidAmerican Energy Company, Nevada Power Company and Sierra Pacific Power Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing portions of this Form 10-K with the reduced disclosure format specified in General Instruction I(2) of Form 10-K.

This combined Form 10-K is separately filed by Berkshire Hathaway Energy Company, PacifiCorp, MidAmerican Funding, LLC, MidAmerican Energy Company, Nevada Power Company and Sierra Pacific Power Company. Information contained herein relating to any individual company is filed by such company on its own behalf. Each company makes no representation as to information relating to the other companies.

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Definition of Abbreviations and Industry Terms

When used in Forward-Looking Statements, Part I - Items 1 through 4, Part II - Items 5 through 7A, and Part III - Items 10 through 14, the following terms have the definitions indicated.

Entity Definitions	
BHE	Berkshire Hathaway Energy Company
Berkshire Hathaway Energy or the 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 and its subsidiaries
Sierra Pacific	Sierra Pacific Power Company and its subsidiaries
Nevada Utilities	Nevada Power Company and Sierra Pacific Power Company
Registrants	Berkshire Hathaway Energy, PacifiCorp, MidAmerican Energy, MidAmerican Funding, Nevada Power and Sierra Pacific
Subsidiary Registrants	PacifiCorp, MidAmerican Energy, MidAmerican Funding, Nevada Power and Sierra Pacific
Northern Powergrid	Northern Powergrid Holdings Company
Northern Natural Gas	Northern Natural Gas Company
Kern River	Kern River Gas Transmission Company
AltaLink	BHE Canada Holdings Corporation
ALP	AltaLink, L.P.
BHE U.S. Transmission	BHE U.S. Transmission, LLC
BHE Renewables, LLC	BHE Renewables, LLC
HomeServices	HomeServices of America, Inc. and its subsidiaries
BHE Pipeline Group or Pipeline Companies	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
ETT	Electric Transmission Texas, LLC
Domestic Regulated Businesses	PacifiCorp, MidAmerican Energy Company, Nevada Power Company, Sierra Pacific Power Company, Northern Natural Gas Company and Kern River Gas Transmission Company
Regulated Businesses	PacifiCorp, MidAmerican Energy Company, Nevada Power Company, Sierra Pacific Power Company, Northern Natural Gas Company, Kern River Gas Transmission Company and AltaLink, L.P.
Utilities	PacifiCorp, MidAmerican Energy Company, Nevada Power Company and Sierra Pacific Power Company
Northern Powergrid Distribution Companies	Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc
Berkshire Hathaway	Berkshire Hathaway Inc.
Topaz	Topaz Solar Farms LLC
Topaz Project	550-megawatt solar project in California
Agua Caliente	Agua Caliente Solar, LLC
Agua Caliente Project	290-megawatt solar project in Arizona
Bishop Hill II	Bishop Hill Energy II LLC
Bishop Hill Project	81-megawatt wind-powered generating facility in Illinois
Pinyon Pines I	Pinyon Pines Wind I, LLC

Pinyon Pines II	Pinyon Pines Wind II, LLC
Pinyon Pines Projects	168-megawatt and 132-megawatt wind-powered generating facilities 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
Solar Star I	Solar Star California XIX, LLC
Solar Star II	Solar Star California XX, LLC

Certain Industry Terms

AESO	Alberta Electric System Operator
AFUDC	Allowance for Funds Used During Construction
AUC	Alberta Utilities Commission
Bcf	Billion cubic feet
BTER	Base Tariff Energy Rates
California ISO	California Independent System Operator Corporation
CPUC	California Public Utilities Commission
DEAA	Deferred Energy Accounting Adjustment
Dodd-Frank Reform Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
Dth	Decatherms
DSM	Demand-side Management
EBA	Energy Balancing Account
ECAC	Energy Cost Adjustment Clause
ECAM	Energy Cost Adjustment Mechanism
EEIR	Energy Efficiency Implementation Rate
EEPR	Energy Efficiency Program Rate
EIM	Energy Imbalance Market
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GEMA	Gas and Electricity Markets Authority
GHG	Greenhouse Gases
GWh	Gigawatt Hours
ICC	Illinois Commerce Commission
IPUC	Idaho Public Utilities Commission
IRP	Integrated Resource Plan
IUB	Iowa Utilities Board
kV	Kilovolt
LNG	Liquefied Natural Gas
LDC	Local Distribution Company
MATS	Mercury and Air Toxics Standards
MISO	Midcontinent Independent System Operator, Inc.
MW	Megawatts
MWh	Megawatt Hours
NERC	North American Electric Reliability Corporation
NRC	Nuclear Regulatory Commission
OCA	Iowa Office of Consumer Advocate

OPUC	Oregon Public Utility Commission
PCAM	Power Cost Adjustment Mechanism
PTAM	Post Test-year Adjustment Mechanism
PUCN	Public Utilities Commission of Nevada
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standards
RRA	Renewable Energy Credit and Sulfur Dioxide Revenue Adjustment Mechanism
RTO	Regional Transmission Organization
SEC	United States Securities and Exchange Commission
SIP	State Implementation Plan
TAM	Transition Adjustment Mechanism
UPSC	Utah Public Service Commission
WECC	Western Electricity Coordinating Council
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 relevant Registrant'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 each Registrant 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 income tax reform, initiatives regarding deregulation and restructuring of the utility industry, and reliability and safety standards, affecting the respective Registrant'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 regulatory rate reviews and other proceedings conducted by regulatory agencies or other governmental and legal bodies and the respective Registrant's ability to recover costs through 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 private generation measures and programs, that could affect customer growth and usage, electricity and natural gas supply or the respective Registrant's ability to obtain long-term contracts with customers and suppliers;
- performance, availability and ongoing operation of the respective Registrant's facilities, including facilities not operated by the Registrants, due to the impacts of market conditions, outages and repairs, transmission constraints, weather, including wind, solar and hydroelectric conditions, and operating conditions;
- the effects of catastrophic and other unforeseen events, which may be caused by factors beyond the control of each respective Registrant or by a breakdown or failure of the Registrants' operating assets, including storms, floods, fires, earthquakes, explosions, landslides, mining accidents, litigation, wars, terrorism, embargoes, and cyber security attacks, data security breaches, disruptions, or other malicious acts;
- a high degree of variance between actual and forecasted load or generation that could impact a Registrant'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 respective Registrant'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 the Registrants' credit facilities;
- changes in the respective Registrant's credit ratings;
- risks relating to nuclear generation, including unique operational, closure and decommissioning risks;
- hydroelectric conditions and the cost, feasibility and eventual outcome of hydroelectric relicensing proceedings;
- 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 ability of the respective Registrants to recover such costs in regulated rates;
- fluctuations in foreign currency exchange rates, primarily the British pound and the Canadian dollar;
- increases in employee healthcare costs;
- 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 transactions;
- 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 consolidated financial results of the respective Registrants;
- the ability to successfully integrate future acquired operations into a Registrant's business; and
- other business or investment considerations that may be disclosed from time to time in the Registrants' filings with the SEC or in other publicly disseminated written documents.

Further details of the potential risks and uncertainties affecting the Registrants are described in the Registrants' filings with the SEC, including Item 1A and other discussions contained in this Form 10-K. Each Registrant 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. Business

GENERAL

BHE is a holding company that owns subsidiaries principally engaged in energy businesses and is a consolidated subsidiary of Berkshire Hathaway. As of February 17, 2017, Berkshire Hathaway, Mr. Walter Scott, Jr., a member of BHE's Board of Directors (along with family members and related entities) and Mr. Gregory E. Abel, BHE's Chairman, President and Chief Executive Officer, owned 90.0%, 9.0% and 1.0%, respectively, of BHE's voting common stock.

Berkshire Hathaway Energy'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. BHE, 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 selling power generated primarily from solar, wind, geothermal and hydroelectric 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.

BHE owns a highly diversified portfolio of primarily regulated businesses that generate, transmit, store, distribute and supply energy and serve customers across geographically diverse service territories in the Western and Midwestern United States, in Great Britain and Canada.

- 90% of Berkshire Hathaway Energy's consolidated operating income during 2016 was generated from rate-regulated businesses.
- The Utilities serve 4.7 million electric and natural gas customers in 11 states in the United States, Northern Powergrid serves 3.9 million end-users in northern England and ALP serves approximately 85% of Alberta, Canada's population.
- As of December 31, 2016, Berkshire Hathaway Energy owned approximately 31,600 MW of generation capacity in operation and under construction:
    - Approximately 27,600 MW of generation capacity is owned by its regulated electric utility businesses;
    - Approximately 4,000 MW of generation capacity is owned by its nonregulated subsidiaries, the majority of which provides power to utilities under long-term contracts; and
    - Berkshire Hathaway Energy's generation capacity in operation and under construction consists of 33% natural gas, 30% wind and solar, 30% coal, 4% hydroelectric and 3% nuclear and other.
    - As of December 31, 2016, Berkshire Hathaway Energy has invested $19 billion in solar, wind, geothermal and biomass generation facilities.
- Berkshire Hathaway Energy owns approximately 32,900 miles of transmission lines and owns a 50% interest in ETT that has approximately 1,200 miles of transmission lines.
- The BHE Pipeline Group owns approximately 16,400 miles of pipeline with a design capacity of approximately 7.9 Bcf of natural gas per day and transported approximately 8% of the total natural gas consumed in the United States during 2016.
- HomeServices closed over $86.5 billion of home sales in 2016, up 11.0% from 2015, and continued to grow its brokerage, mortgage and franchise businesses. HomeServices' franchise business operates in 47 states with over 375 franchisees throughout the country.

As of December 31, 2016, Berkshire Hathaway Energy had approximately 21,000 employees, of which approximately 8,400 are covered by union contracts. The majority of the union employees are employed by the Utilities and are represented by the International Brotherhood of Electrical Workers, the Utility Workers Union of America, the United Utility Workers Association and the International Brotherhood of Boilermakers. These collective bargaining agreements have expiration dates ranging through August 2024. HomeServices currently has over 29,000 agents who are independent contractors and not employees.

Refer to Note 21 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K for additional reportable segment information.

BHE's principal executive offices are located at 666 Grand Avenue, Suite 500, Des Moines, Iowa 50309-2580 and its telephone number is (515) 242-4300. BHE was initially incorporated in 1971 as California Energy Company, Inc. under the laws of the state of Delaware and through a merger transaction in 1999 was reincorporated in Iowa under the name MidAmerican Energy Holdings Company. In 2014, its name was changed to Berkshire Hathaway Energy Company.

PACIFICORP

General

PacifiCorp, an indirect wholly owned subsidiary of BHE, is a United States regulated electric utility company headquartered in Oregon that serves 1.8 million retail electric customers in portions of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp is principally engaged in the business of generating, transmitting, distributing and selling electricity. PacifiCorp's combined service territory covers approximately 143,000 square miles and includes diverse regional economies across six states. No single segment of the economy dominates the service territory, which helps mitigate PacifiCorp's exposure to economic fluctuations. In the eastern portion of the service territory, consisting of Utah, Wyoming and southeastern Idaho, the principal industries are manufacturing, mining or extraction of natural resources, agriculture, technology, recreation and government. In the western portion of the service territory, consisting of Oregon, southern Washington and northern California, the principal industries are agriculture, manufacturing, forest products, food processing, technology, government and primary metals. In addition to retail sales, PacifiCorp buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants to balance and optimize the economic benefits of electricity generation, retail customer loads and existing wholesale transactions. Certain PacifiCorp subsidiaries support its electric utility operations by providing coal mining services.

PacifiCorp's operations are conducted under numerous franchise agreements, certificates, permits and licenses obtained from federal, state and local authorities. The average term of the franchise agreements is approximately 25 years, although their terms range from five years to indefinite. Several of these franchise agreements allow the municipality the right to seek amendment to the franchise agreement at a specified time during the term. PacifiCorp generally has an exclusive right to serve electric customers within its service territories and, in turn, has an obligation to provide electric service to those customers. In return, the state utility commissions have established rates on a cost-of-service basis, which are designed to allow PacifiCorp an opportunity to recover its costs of providing services and to earn a reasonable return on its investments.

PacifiCorp's principal executive offices are located at 825 N.E. Multnomah Street, Portland, Oregon 97232, and its telephone number is (888) 221-7070. PacifiCorp was initially incorporated in 1910 under the laws of the state of Maine under the name Pacific Power & Light Company. In 1984, Pacific Power & Light Company changed its name to PacifiCorp. In 1989, it merged with Utah Power and Light Company, a Utah corporation, in a transaction wherein both corporations merged into a newly formed Oregon corporation. The resulting Oregon corporation was re-named PacifiCorp, which is the operating entity today. PacifiCorp delivers electricity to customers in Utah, Wyoming and Idaho under the trade name Rocky Mountain Power and to customers in Oregon, Washington and California under the trade name Pacific Power.

BHE controls substantially all of PacifiCorp's voting securities, which include both common and preferred stock.

Regulated Electric Operations

Customers

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

	2016		2015		2014	
Utah	24,020	44%	24,158	44%	24,105	44%
Oregon	12,869	24	12,863	24	12,959	24
Wyoming	9,189	17	9,330	17	9,568	17
Washington	3,982	7	4,108	8	4,118	8
Idaho	3,510	7	3,443	6	3,495	6
California	748	1	739	1	754	1
	54,318	100%	54,641	100%	54,999	100%

Electricity sold to PacifiCorp's retail and wholesale customers by class of customer and the average number of retail customers for the years ended December 31 were as follows:

	2016		2015		2014	
GWh sold:						
Residential	16,058	26%	15,566	25%	15,568	24%
Commercial	16,857	28	17,262	27	17,073	26
Industrial and irrigation	20,924	34	21,403	34	21,934	34
Other	479	1	410	—	424	—
Total retail	54,318	89	54,641	86	54,999	84
Wholesale	6,641	11	8,889	14	10,270	16
Total GWh sold	60,959	100%	63,530	100%	65,269	100%
Average number of retail customers (in thousands):						
Residential	1,599	87%	1,574	87%	1,546	87%
Commercial	205	11	202	11	200	11
Industrial and irrigation	33	2	33	2	33	2
Other	4	—	4	—	4	—
Total	1,841	100%	1,813	100%	1,783	100%
Retail customers:						
Average usage per customer (kilowatt hours)	29,505		30,139		30,846	
Average revenue per customer	$ 2,642		$ 2,652		$ 2,645	
Revenue per kilowatt hour	9.0¢		8.8¢		8.6¢	

Changes in economic and weather conditions, as well as various conservation, energy efficiency and customer self-generation measures and programs, impact PacifiCorp's customer usage.

The annual hourly peak customer demand, which represents the highest demand on a given day and at a given hour, occurs in the summer when air conditioning and irrigation systems are heavily used. The winter also experiences a peak demand due to heating requirements. During 2016, PacifiCorp's peak demand was 10,139 MW in the summer and 8,708 MW in the winter.

Generating Facilities and Fuel Supply

PacifiCorp has ownership interest in a diverse portfolio of generating facilities. The following table presents certain information regarding PacifiCorp's owned generating facilities as of December 31, 2016:

Generating Facility	Location	Energy Source	Installed	Facility Net Capacity (MW)[1]	Net Owned Capacity (MW)[1]
COAL:					
Jim Bridger Nos. 1, 2, 3 and 4	Rock Springs, WY	Coal	1974-1979	2,123	1,415
Hunter Nos. 1, 2 and 3	Castle Dale, UT	Coal	1978-1983	1,363	1,158
Huntington Nos. 1 and 2	Huntington, UT	Coal	1974-1977	909	909
Dave Johnston Nos. 1, 2, 3 and 4	Glenrock, WY	Coal	1959-1972	760	760
Naughton Nos. 1, 2 and 3[2]	Kemmerer, WY	Coal	1963-1971	637	637
Cholla No. 4	Joseph City, AZ	Coal	1981	395	395
Wyodak No. 1	Gillette, WY	Coal	1978	332	266
Craig Nos. 1 and 2	Craig, CO	Coal	1979-1980	855	165
Colstrip Nos. 3 and 4	Colstrip, MT	Coal	1984-1986	1,480	148
Hayden Nos. 1 and 2	Hayden, CO	Coal	1965-1976	446	78
				9,300	5,931
NATURAL GAS:					
Lake Side 2	Vineyard, UT	Natural gas/steam	2014	631	631
Lake Side	Vineyard, UT	Natural gas/steam	2007	546	546
Currant Creek	Mona, UT	Natural gas/steam	2005-2006	524	524
Chehalis	Chehalis, WA	Natural gas/steam	2003	477	477
Hermiston	Hermiston, OR	Natural gas/steam	1996	461	231
Gadsby Steam	Salt Lake City, UT	Natural gas	1951-1955	238	238
Gadsby Peakers	Salt Lake City, UT	Natural gas	2002	119	119
				2,996	2,766
HYDROELECTRIC:[3]					
Lewis River System	WA	Hydroelectric	1931-1958	578	578
North Umpqua River System	OR	Hydroelectric	1950-1956	204	204
Klamath River System	CA, OR	Hydroelectric	1903-1962	170	170
Bear River System	ID, UT	Hydroelectric	1908-1984	105	105
Rogue River System	OR	Hydroelectric	1912-1957	52	52
Minor hydroelectric facilities	Various	Hydroelectric	1895-1986	26	26
				1,135	1,135
WIND:[3]					
Marengo	Dayton, WA	Wind	2007-2008	210	210
Glenrock	Glenrock, WY	Wind	2008-2009	138	138
Seven Mile Hill	Medicine Bow, WY	Wind	2008	119	119
Dunlap Ranch	Medicine Bow, WY	Wind	2010	111	111
Leaning Juniper	Arlington, OR	Wind	2006	100	100
High Plains	McFadden, WY	Wind	2009	99	99
Rolling Hills	Glenrock, WY	Wind	2009	99	99
Goodnoe Hills	Goldendale, WA	Wind	2008	94	94
Foote Creek	Arlington, WY	Wind	1999	41	32
McFadden Ridge	McFadden, WY	Wind	2009	28	28
				1,039	1,030
OTHER:[3]					
Blundell	Milford, UT	Geothermal	1984, 2007	32	32
				32	32
Total Available Generating Capacity				14,502	10,894

(1) Facility Net Capacity represents the lesser of nominal ratings or any limitations under applicable interconnection, power purchase, or other agreements for intermittent resources and the total net dependable capability available during summer conditions for all other units. An intermittent resource's nominal rating is the manufacturer's contractually specified capability (in MW) under specified conditions. Net Owned Capacity indicates PacifiCorp's ownership of Facility Net Capacity.

(2) As required by current state permits, PacifiCorp currently plans to remove Naughton Unit No. 3 (280 MW) from coal-fueled service by year-end 2017. However, a request has been submitted to and is being considered by the state of Wyoming that would allow the unit to operate as a coal-fueled unit until no later than January 30, 2019, and then either close or be converted to natural gas. Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion.

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

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

	2016	2015	2014
Coal	56%	61%	60%
Natural gas	15	14	16
Hydroelectric[1]	6	4	5
Wind and other[1]	5	4	5
Total energy generated	82	83	86
Energy purchased - short-term contracts and other	10	9	6
Energy purchased - long-term contracts (renewable)[1]	8	5	5
Energy purchased - long-term contracts (non-renewable)	—	3	3
	100%	100%	100%

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

PacifiCorp is required to have resources available to continuously meet its customer needs and reliably operate its electric system. The percentage of PacifiCorp's energy supplied by energy source varies from year to year and is subject to numerous operational and economic factors such as planned and unplanned outages, fuel commodity prices, fuel transportation costs, weather, environmental considerations, transmission constraints, and wholesale market prices of electricity. PacifiCorp evaluates these factors continuously in order to facilitate economical dispatch of its generating facilities. When factors for one energy source are less favorable, PacifiCorp places more reliance on other energy sources. For example, PacifiCorp can generate more electricity using its low cost hydroelectric and wind-powered generating facilities when factors associated with these facilities are favorable. In addition to meeting its customers' energy needs, PacifiCorp is required to maintain operating reserves on its system to mitigate the impacts of unplanned outages or other disruption in supply, and to meet intra-hour changes in load and resource balance. This operating reserve requirement is dispersed across PacifiCorp's generation portfolio on a least-cost basis based on the operating characteristics of the portfolio. Operating reserves may be held on hydroelectric, coal-fueled or natural gas-fueled resources. PacifiCorp manages certain risks relating to its supply of electricity and fuel requirements by entering into various contracts, which may be accounted for as derivatives and may include forwards, options, swaps and other agreements. Refer to "General Regulation" in Item 1 of this Form 10-K for a discussion of energy cost recovery by jurisdiction and to PacifiCorp's Item 7A in this Form 10-K for a discussion of commodity price risk and derivative contracts.

Coal

PacifiCorp has interests in coal mines that support its coal-fueled generating facilities and operates the Bridger surface and Bridger underground coal mines. In 2015, PacifiCorp idled the Deer Creek underground coal mine that historically served the Huntington, Hunter and Carbon Unit Nos. 1 and 2 ("Carbon Facility") generating facilities and commenced reclamation activities. These mines supplied 15%, 18% and 27% of PacifiCorp's total coal requirements during the years ended December 31, 2016, 2015 and 2014, respectively. The remaining coal requirements are acquired through long and short-term third-party contracts. PacifiCorp also operates the Wyodak Coal Crushing Facility.

Most of PacifiCorp's coal reserves are held pursuant to leases through the federal Bureau of Land Management and from certain states and private parties. The leases generally have multi-year terms that may be renewed or extended only with the consent of the lessor and require payment of rents and royalties. In addition, federal and state regulations require that comprehensive environmental protection and reclamation standards be met during the course of mining operations and upon completion of mining activities.

Coal reserve estimates are subject to adjustment as a result of the development of additional engineering and geological data, new mining technology and changes in regulation and economic factors affecting the utilization of such reserves. PacifiCorp's recoverable coal reserves of operating mines as of December 31, 2016, based on recent engineering studies, were as follows (in millions):

Coal Mine	Location	Generating Facility Served	Mining Method	Recoverable Tons	
Bridger	Rock Springs, WY	Jim Bridger	Surface	31	(1)
Bridger	Rock Springs, WY	Jim Bridger	Underground	8	(1)
Trapper	Craig, CO	Craig	Surface	5	(2)
				44	

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

(2) These coal reserves are leased and mined by Trapper Mining Inc., a cooperative in which PacifiCorp has an ownership interest of 21%. The amount included above represents only PacifiCorp's 21% interest in the coal reserves. PacifiCorp does not operate the Trapper mine.

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

Natural Gas

PacifiCorp uses natural gas as fuel for its combined and simple-cycle natural gas-fueled generating facilities and for the Gadsby Steam generating facility. Oil and natural gas are also used for igniter fuel and standby purposes. These sources are presently in adequate supply and available to meet PacifiCorp's needs.

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

Hydroelectric

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

PacifiCorp operates the majority of its hydroelectric generating portfolio under long-term licenses. The FERC regulates 99% of the net capacity of this portfolio through 15 individual licenses, which have terms of 30 to 50 years. The licenses for major hydroelectric generating facilities expire at various dates through May 2058. A portion of this portfolio is licensed under the Oregon Hydroelectric Act. For discussion of PacifiCorp's hydroelectric relicensing activities, including updated information regarding the Klamath River hydroelectric system, refer to Note 16 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 13 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K.

Wind and Other Renewable Resources

PacifiCorp has pursued renewable resources as a viable, economical and environmentally prudent means of supplying electricity and complying with laws and regulations. Renewable resources have low to no emissions and require little or no fossil fuel. PacifiCorp's wind-powered generating facilities, including those facilities where a significant portion of the equipment will be replaced, are eligible for federal renewable electricity production tax credits for 10 years from the date the facilities are placed in-service. Production tax credits for PacifiCorp's currently eligible wind-powered generating facilities began expiring in 2016, with final expiration in 2020.

Wholesale Activities

PacifiCorp purchases and sells electricity in the wholesale markets as needed to balance its generation with its retail load obligations. PacifiCorp may also purchase electricity in the wholesale markets when it is more economical than generating electricity from its own facilities and may sell surplus electricity in the wholesale markets when it can do so economically. When prudent, PacifiCorp enters into financial swap contracts and forward electricity sales and purchases for physical delivery at fixed prices to reduce its exposure to electricity price volatility.

Transmission and Distribution

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

PacifiCorp's transmission system is part of the Western Interconnection, which includes the interconnected transmission systems of 14 western states, two Canadian provinces and parts of Mexico. PacifiCorp's transmission system, together with contractual rights on other transmission systems, enables PacifiCorp to integrate and access generation resources to meet its customer load requirements. PacifiCorp's transmission and distribution systems included approximately 16,500 miles of transmission lines in nine states, 63,000 miles of distribution lines and 900 substations as of December 31, 2016.

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

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

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

PacifiCorp and the California ISO implemented an EIM in November 2014. The EIM expands the real-time component of the California ISO's market technology to optimize and balance electricity supply and demand every five minutes across the entire PacifiCorp and California ISO EIM footprint. The EIM is voluntary and available to all balancing authorities in the Western United States. EIM market participants submit bids to the California ISO market operator before each hour for each generating resource they choose to be dispatched by the market. Each bid is comprised of a dispatchable operating range, ramp rate and prices across the operating range. The California ISO market operator uses sophisticated technology to select the least-cost resources to meet demand and send simultaneous dispatch signals to every participating generator across the EIM footprint every five minutes. In addition to generation resource bids, the California ISO market operator also receives continuous real-time updates of the transmission grid network, meteorological and load forecast information that it uses to optimize dispatch instructions. Outside the EIM footprint, utilities in the Western United States do not utilize comparable technology and are largely limited to transactions within the borders of their balancing authority area to balance supply and demand intra-hour using a combination of manual and automated dispatch. The EIM delivers customer benefits by leveraging automation and resource diversity to result in more efficient dispatch, more effective integration of renewables and improved situational awareness. Benefits to customers have increased since NV Energy, Puget Sound Energy and Arizona Public Service joined the EIM in 2015 and 2016, and benefits are expected to increase further with renewable resource expansion and as more entities join the EIM bringing incremental diversity.

PacifiCorp and the California ISO are exploring the feasibility, costs and benefits of PacifiCorp joining a regional Independent System Operator ("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. California Senate Bill No. 350, which was passed in October 2015, authorizes the California legislature to consider making changes to current laws that would create an independent governance structure for a regional ISO during the 2017 legislative session. 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. Joining the regional ISO would extend PacifiCorp's current participation in the real-time market through the EIM to participation in the day-ahead energy market operated by the California ISO, in addition to unified planning and operation of PacifiCorp's transmission network.

PacifiCorp's Energy Gateway Transmission Expansion Program represents plans to build approximately 2,000 miles of new high-voltage transmission lines, with an estimated cost exceeding $6 billion, primarily in Wyoming, Utah, Idaho and Oregon. The $6 billion estimated cost includes: (a) the 135-mile, 345-kV Populus to Terminal transmission line between the Terminal substation near the Salt Lake City Airport and the Populus substation in Downey, Idaho placed in-service in 2010; (b) the 100-mile, 345/50-kV Mona to Oquirrh transmission line between the Mona substation in central Utah and the Oquirrh substation in the Salt Lake Valley placed in-service in 2013; (c) the 170-mile, 345-kV transmission line between the Sigurd Substation in central Utah and the Red Butte Substation in southwest Utah placed in-service in May 2015; and (d) other segments that are expected to be placed in-service in future years, depending on load growth, siting, permitting and construction schedules. The transmission line segments are intended to: (a) address customer load growth; (b) improve system reliability; (c) reduce transmission system constraints; (d) provide access to diverse generation resources, including renewable resources; and (e) improve the flow of electricity throughout PacifiCorp's six-state service area. Proposed transmission line segments are evaluated to ensure optimal benefits and timing before committing to move forward with permitting and construction. Through December 31, 2016, $1.9 billion had been spent and $1.6 billion, including AFUDC, had been placed in-service.

Future Generation, Conservation and Energy Efficiency

Integrated Resource Plan

As required by certain state regulations, PacifiCorp uses an IRP to develop a long-term resource plan to ensure that PacifiCorp can continue to provide reliable and cost-effective electric service to its customers while maintaining compliance with existing and evolving environmental laws and regulations. The IRP process identifies the amount and timing of PacifiCorp's expected future resource needs, accounting for planning uncertainty, risks, reliability, state energy policies and other factors. The IRP is prepared following a public process, which provides an opportunity for stakeholders to participate in PacifiCorp's resource planning process. PacifiCorp files its IRP on a biennial basis with the state commissions in each of the six states where PacifiCorp operates. Five states indicate whether the IRP meets the state commission's IRP standards and guidelines, a process referred to as "acknowledgment" in some states.

In March 2015, PacifiCorp filed its 2015 IRP with the state commissions. In 2015, the WPSC accepted the 2015 IRP into its files and the UPSC, IPUC and WUTC acknowledged the 2015 IRP. In February 2016, the OPUC acknowledged the 2015 IRP with one exception. In March 2016, PacifiCorp filed its update to the 2015 IRP with the state commissions. PacifiCorp is currently developing its 2017 IRP that is expected to be filed in March 2017.

Requests for Proposals

PacifiCorp issues individual Request for Proposals ("RFP"), each of which typically focuses on a specific category of generation resources consistent with the IRP or other customer-driven demands. The IRP and the RFPs provide for the identification and staged procurement of resources to meet load or renewable portfolio standard requirements. Depending upon the specific RFP, applicable laws and regulations may require PacifiCorp to file draft RFPs with the UPSC, the OPUC and the WUTC. Approval by the UPSC, the OPUC or the WUTC may be required depending on the nature of the RFPs.

PacifiCorp issued renewable resource and renewable energy credit RFPs to the market on April 11, 2016. The RFPs were issued to seek cost-effective renewable resources and RECs that can take full advantage of federal income tax incentives and that can be used to meet renewable portfolio standard requirements in Oregon, Washington, and California. PacifiCorp executed REC purchase agreements from one wind project offering prior-year vintage RECs and from six solar projects offering RECs that will be generated over the period 2016 through 2036. The solar projects are located in Oregon and Utah and have an aggregate capacity of 169 MW.

Utah Subscriber Solar Program

In October 2015, the UPSC approved the Utah Subscriber Solar Program that allows Utah customers to meet a portion or all of their energy requirements from Utah-based solar photovoltaic resources. The program is an alternative for customers who are unable or do not want to install solar. Residential and small commercial participants will be able to subscribe in 200 kilowatt-hour blocks up to their total annual usage. Large commercial and industrial participants will be able to subscribe in 1 kilowatt blocks up to their total annual usage. As part of the program, PacifiCorp issued a 2015 Solar RFP to seek solar photovoltaic resources up to 20 MW sited in Utah. The contract for the solar resource was executed in January 2016 and the plant officially started generating service for the Subscriber Solar Program on December 30, 2016. Enrollment began May 2016 for commercial customers and June 2016 for residential customers, and was sold out within 26 weeks.

Demand-side Management

PacifiCorp has provided a comprehensive set of DSM programs to its customers since the 1970s. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. PacifiCorp offers services to customers such as energy engineering audits and information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, PacifiCorp offers rebates or incentives encouraging the purchase and installation of high-efficiency equipment such as lighting, heating and cooling equipment, weatherization, motors, process equipment and systems, as well as incentives for energy project management, efficient building operations and efficient construction. Incentives are also paid to solicit participation in load management programs by residential, business and agricultural customers through programs such as PacifiCorp's residential and small commercial air conditioner load control program and irrigation equipment load control programs. Although subject to prudence reviews, state regulations allow for contemporaneous recovery of costs incurred for the DSM programs through state-specific energy efficiency surcharges to retail customers or for recovery of costs through rates. During 2016, PacifiCorp spent $142 million on these DSM programs, resulting in an estimated 685,109 MWh of first-year energy savings and an estimated 290 MW of peak load management. In March 2016, the Utah Legislature approved Senate Bill 115, "Sustainable Transportation and Energy Plan Act" that will enable PacifiCorp to amortize DSM program costs over a 10 year period beginning in 2017. In addition to these DSM programs, PacifiCorp has load curtailment contracts with a number of large industrial customers that deliver up to 305 MW of load reduction when needed, depending on the customers' actual loads. Recovery of the costs associated with the large industrial load management program are captured in the retail special contract agreements with those customers approved by their respective state commissions or through PacifiCorp's general rate case process.

Employees

As of December 31, 2016, PacifiCorp had approximately 5,600 employees, of which approximately 3,300 were covered by union contracts, principally with the International Brotherhood of Electrical Workers, the Utility Workers Union of America and the International Brotherhood of Boilermakers.

MIDAMERICAN FUNDING AND MIDAMERICAN ENERGY

MidAmerican Funding is an Iowa limited liability company whose sole member is BHE. MidAmerican Funding, a holding company, owns all of the outstanding common stock of MHC, which is a holding company owning all of the common stock of MidAmerican Energy; Midwest Capital Group, Inc. ("Midwest Capital"); and MEC Construction Services Co. ("MEC Construction"). MidAmerican Energy is a public utility company headquartered in Des Moines, Iowa, and incorporated in the state of Iowa. MHC, MidAmerican Funding and BHE are also headquartered in Des Moines, Iowa.

MidAmerican Funding and MHC

MidAmerican Funding conducts no business other than activities related to its debt securities and the ownership of MHC. MHC conducts no business other than the ownership of its subsidiaries and related corporate services. MidAmerican Energy accounts for the predominant part of MidAmerican Funding's and MHC's assets, revenue and earnings. Financial information on MidAmerican Funding's segments of business is in Note 20 of the Notes to Consolidated Financial Statements of MidAmerican Funding in Item 8 of this Form 10-K.

MidAmerican Energy

General

MidAmerican Energy, an indirect wholly owned subsidiary of BHE, is a United States regulated electric and natural gas utility company that serves 0.8 million regulated retail electric customers in portions of Iowa, Illinois and South Dakota and 0.7 million regulated retail and transportation natural gas customers in portions of Iowa, South Dakota, Illinois and Nebraska. MidAmerican Energy is principally engaged in the business of generating, transmitting, distributing and selling electricity and in distributing, selling and transporting natural gas. MidAmerican Energy's service territory covers approximately 11,000 square miles. Metropolitan areas in which MidAmerican Energy distributes electricity at retail include Council Bluffs, Des Moines, Fort Dodge, Iowa City, Sioux City and Waterloo, Iowa; and the Quad Cities (Davenport and Bettendorf, Iowa and Rock Island and Moline, Illinois). Metropolitan areas in which it distributes natural gas at retail include Cedar Rapids, Des Moines, Fort Dodge, Iowa City, Sioux City and Waterloo, Iowa; the Quad Cities; and Sioux Falls, South Dakota. MidAmerican Energy has a diverse customer base consisting of urban and rural residential customers and a variety of commercial and industrial customers. Principal industries served by MidAmerican Energy include processing and sales of food products; manufacturing, processing and fabrication of primary metals; farm and other non-electrical machinery; real estate; electronic data storage; cement and gypsum products; financial services; and government. In addition to retail sales and natural gas transportation, MidAmerican Energy sells electricity principally to markets operated by RTOs and natural gas to other utilities and market participants on a wholesale basis. MidAmerican Energy is a transmission-owning member of the MISO and participates in its energy, capacity and ancillary services markets.

MidAmerican Energy's regulated electric and natural gas operations are conducted under numerous franchise agreements, certificates, permits and licenses obtained from federal, state and local authorities. The franchise agreements, with various expiration dates, are typically for 20- to 25-year terms. Several of these franchise agreements give either party the right to seek amendment to the franchise agreement at one or two specified times during the term. MidAmerican Energy generally has an exclusive right to serve electric customers within its service territories and, in turn, has an obligation to provide electricity service to those customers. In return, the state utility commissions have established rates on a cost-of-service basis, which are designed to allow MidAmerican Energy an opportunity to recover its costs of providing services and to earn a reasonable return on its investment. In Illinois, MidAmerican Energy's regulated retail electric customers may choose their energy supplier.

Prior to 2016, MidAmerican Energy also had nonregulated business activities consisting predominantly of competitive electricity and natural gas. On January 1, 2016, MidAmerican Energy transferred the assets and liabilities of its unregulated retail services business to MidAmerican Energy Services, LLC, a subsidiary of BHE.

MidAmerican Energy had total assets of $15.5 billion as of December 31, 2016, and total operating revenue of $2.6 billion for 2016. Financial information on MidAmerican Energy's segments of business is disclosed in MidAmerican Energy's Note 20 of Notes to Financial Statements in Item 8 of this Form 10-K.

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

	2016	2015	2014
Operating revenue:			
Regulated electric	76%	74%	65%
Regulated gas	24	26	35
	100%	100%	100%
Operating income:			
Regulated electric	88%	86%	81%
Regulated gas	12	14	19
	100%	100%	100%

Regulated Electric Operations

Customers

The GWh and percentages of electricity sold to MidAmerican Energy's retail customers by jurisdiction for the years ended December 31 were as follows:

	2016		2015		2014	
Iowa	21,766	91%	20,922	90%	20,585	90%
Illinois	1,940	8	1,903	9	1,975	9
South Dakota	218	1	217	1	217	1
	23,924	100%	23,042	100%	22,777	100%

Electricity sold to MidAmerican Energy's retail and wholesale customers by class of customer and the average number of retail customers for the years ended December 31 were as follows:

	2016		2015		2014	
GWh sold:						
Residential	6,408	20%	6,166	19%	6,429	20%
Commercial	3,812	12	3,806	12	4,084	12
Industrial	12,115	37	11,487	36	10,642	33
Other	1,589	5	1,583	5	1,622	5
Total retail	23,924	74	23,042	72	22,777	70
Wholesale	8,489	26	8,741	28	9,716	30
Total GWh sold	32,413	100%	31,783	100%	32,493	100%
Average number of retail customers (in thousands):						
Residential	653	86%	646	86%	643	86%
Commercial	91	12	90	12	87	12
Industrial	2	—	2	—	2	—
Other	14	2	14	2	14	2
Total	760	100%	752	100%	746	100%

In addition to the variations in weather from year to year, fluctuations in economic conditions within MidAmerican Energy's service territory and elsewhere can impact customer usage, particularly for industrial customers. Wholesale sales are impacted by market prices for energy relative to the incremental cost to generate power.

There are seasonal variations in MidAmerican Energy's electricity sales that are principally related to weather and the related use of electricity for air conditioning. Additionally, electricity sales are priced higher in the summer months compared to the remaining months of the year. As a result, 40% to 50% of MidAmerican Energy's regulated electric revenue is reported in the months of June, July, August and September.

A degree of concentration of sales exists with certain large electric retail customers. Sales to the ten largest customers, from a variety of industries, comprised 16%, 15% and 14% of total retail electric sales in 2016, 2015 and 2014, respectively.

The annual hourly peak demand on MidAmerican Energy's electric system usually occurs as a result of air conditioning use during the cooling season. Peak demand represents the highest demand on a given day and at a given hour. On July 21, 2016, retail customer usage of electricity caused an hourly peak demand of 4,698 MW on MidAmerican Energy's electric distribution system, which is 54 MW less than the record hourly peak demand of 4,752 MW set July 19, 2011.

Generating Facilities and Fuel Supply

MidAmerican Energy has ownership interest in a diverse portfolio of generating facilities. The following table presents certain information regarding MidAmerican Energy's owned generating facilities as of December 31, 2016:

Generating Facility	Location	Energy Source	Year Installed	Facility Net Capacity (MW)[1]	Net Owned Capacity (MW)[1]
WIND:					
Adair	Adair, IA	Wind	2008	175	175
Adams	Lennox, IA	Wind	2015	150	150
Carroll	Carroll, IA	Wind	2008	150	150
Century	Blairsburg, IA	Wind	2005-2008	200	200
Charles City	Charles City, IA	Wind	2008	75	75
Eclipse	Adair, IA	Wind	2012	200	200
Highland	Primghar, IA	Wind	2015	475	475
Ida Grove	Ida Grove, IA	Wind	2016	300	300
Intrepid	Schaller, IA	Wind	2004-2005	176	176
Laurel	Laurel, IA	Wind	2011	120	120
Lundgren	Otho, IA	Wind	2014	250	250
Macksburg	Macksburg, IA	Wind	2014	119	119
Morning Light	Adair, IA	Wind	2012	100	100
O'Brien	Primghar, IA	Wind	2016	250	250
Pomeroy	Pomeroy, IA	Wind	2007-2011	286	286
Rolling Hills	Massena, IA	Wind	2011	443	443
Victory	Westside, IA	Wind	2006	99	99
Vienna	Gladbrook, IA	Wind	2012-2013	150	150
Walnut	Walnut, IA	Wind	2008	150	150
Wellsburg	Wellsburg, IA	Wind	2014	139	139
				4,007	4,007
COAL:					
George Neal Unit No. 3	Sergeant Bluff, IA	Coal	1975	518	373
George Neal Unit No. 4	Salix, IA	Coal	1979	660	268
Louisa	Muscatine, IA	Coal	1983	740	651
Ottumwa	Ottumwa, IA	Coal	1981	730	380
Walter Scott, Jr. Unit No. 3	Council Bluffs, IA	Coal	1978	702	555
Walter Scott, Jr. Unit No. 4	Council Bluffs, IA	Coal	2007	806	481
				4,156	2,708
NATURAL GAS AND OTHER:					
Greater Des Moines	Pleasant Hill, IA	Gas	2003-2004	481	481
Coralville	Coralville, IA	Gas	1970	63	63
Electrifarm	Waterloo, IA	Gas or Oil	1975-1978	182	182
Moline	Moline, IL	Gas	1970	61	61
Parr	Charles City, IA	Gas	1969	33	33
Pleasant Hill	Pleasant Hill, IA	Gas or Oil	1990-1994	160	160
River Hills	Des Moines, IA	Gas	1966-1967	115	115
Riverside Unit No. 5	Bettendorf, IA	Gas	1961	123	123
Sycamore	Johnston, IA	Gas or Oil	1974	148	148
28 portable power modules	Various	Oil	2000	56	56
				1,422	1,422
NUCLEAR:					
Quad Cities Unit Nos. 1 and 2	Cordova, IL	Uranium	1972	1,824	456
HYDROELECTRIC:					
Moline Unit Nos. 1-4[2]	Moline, IL	Hydroelectric	1941	2	2
Total Available Generating Capacity				11,411	8,595
PROJECTS UNDER CONSTRUCTION					
Various wind projects				2,000	2,000
				13,411	10,595

(1) Facility Net Capacity represents the lesser of nominal ratings or any limitations under applicable interconnection, power purchase, or other agreements for intermittent resources and the total net dependable capability available during summer conditions for all other units. An intermittent resource's nominal rating is the manufacturer's contractually specified capability (in MW) under specified conditions. Net Owned Capacity indicates MidAmerican Energy's ownership of Facility Net Capacity.

(2) Three of the Moline hydroelectric units were out of service and not accredited by the MISO in 2016.

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

	2016	2015	2014
Coal	39%	48%	55%
Nuclear	12	12	12
Natural gas	2	1	—
Wind and other[1]	35	29	24
Total energy generated	88	90	91
Energy purchased - short-term contracts and other	10	8	7
Energy purchased - long-term contracts (renewable)[1]	1	1	1
Energy purchased - long-term contracts (non-renewable)	1	1	1
	100%	100%	100%

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

MidAmerican Energy is required to have resources available to continuously meet its customer needs. The percentage of MidAmerican Energy's energy supplied by energy source varies from year to year and is subject to numerous operational and economic factors such as planned and unplanned outages, fuel commodity prices, fuel transportation costs, weather, environmental considerations, transmission constraints, and market prices of electricity. When factors for one energy source are less favorable, MidAmerican Energy places more reliance on other energy sources. For example, MidAmerican Energy can generate more electricity using its low cost wind-powered generating facilities when factors associated with these facilities are favorable. When factors associated with wind resources are less favorable, MidAmerican Energy must increase its reliance on more expensive generation or purchased electricity. Refer to "General Regulation" in Item 1 of this Form 10-K for a discussion of energy cost recovery by jurisdiction.

All of the coal-fueled generating facilities operated by MidAmerican Energy are fueled by low-sulfur, western coal from the Powder River Basin in northeast Wyoming. MidAmerican Energy's coal supply portfolio includes multiple suppliers and mines under short-term and multi-year agreements of varying terms and quantities through 2019. MidAmerican Energy believes supplies from these sources are presently adequate and available to meet MidAmerican Energy's needs. MidAmerican Energy's coal supply portfolio has substantially all of its expected 2017 requirements under fixed-price contracts. MidAmerican Energy regularly monitors the western coal market for opportunities to enhance its coal supply portfolio.

MidAmerican Energy has a multi-year long-haul coal transportation agreement with BNSF Railway Company ("BNSF"), an affiliate company, for the delivery of coal to all of the MidAmerican Energy-operated coal-fueled generating facilities other than the George Neal Energy Center. Under this agreement, BNSF delivers coal directly to MidAmerican Energy's Walter Scott, Jr. Energy Center and to an interchange point with Canadian Pacific Railway Company for short-haul delivery to the Louisa Energy Center. MidAmerican Energy has a multi-year long-haul coal transportation agreement with Union Pacific Railroad Company for the delivery of coal to the George Neal Energy Center.

MidAmerican Energy is a 25% joint owner of Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station"), a nuclear power plant. Exelon Generation Company, LLC ("Exelon Generation"), a subsidiary of Exelon Corporation, is the 75% joint owner and the operator of Quad Cities Station. Approximately one-third of the nuclear fuel assemblies in each reactor core at Quad Cities Station is replaced every 24 months. MidAmerican Energy has been advised by Exelon Generation that the following requirements for Quad Cities Station can be met under existing supplies or commitments: uranium requirements through 2021 and partial requirements through 2022; uranium conversion requirements through 2021 and partial requirements through 2025; enrichment requirements through 2020 and partial requirements through 2025; and fuel fabrication requirements through 2022. MidAmerican Energy has been advised by Exelon Generation that it does not anticipate it will have difficulty in contracting for uranium, uranium conversion, enrichment or fabrication of nuclear fuel needed to operate Quad Cities Station during these time periods.

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

MidAmerican Energy owns more wind-powered generating capacity than any other United States rate-regulated electric utility and believes wind-powered generation offers a viable, economical and environmentally prudent means of supplying electricity and complying with laws and regulations. Pursuant to ratemaking principles approved by the IUB, all of MidAmerican Energy's wind-powered generating facilities in service at December 31, 2016, are authorized to earn a fixed rate of return on equity over their useful lives ranging from 11.35% to 12.2% in any future Iowa rate proceeding. MidAmerican Energy's wind-powered generating facilities, including those facilities where a significant portion of the equipment will be replaced, are eligible for federal renewable electricity production tax credits for 10 years from the date the facilities are placed in service. Production tax credits for MidAmerican Energy's wind-powered generating facilities currently in service, began expiring in 2014, with final expiration in 2026.

MidAmerican Energy sells and purchases electricity and ancillary services related to its generation and load in wholesale markets pursuant to the tariffs in those markets. MidAmerican Energy participates predominantly in the MISO energy and ancillary service markets, which provide MidAmerican Energy with wholesale opportunities over a large market area. MidAmerican Energy can enter into wholesale bilateral transactions in addition to market activity related to its assets. MidAmerican Energy is authorized to participate in the Southwest Power Pool, Inc. and PJM Interconnection, L.L.C. ("PJM") markets and can contract with several other major transmission-owning utilities in the region. MidAmerican Energy can utilize both financial swaps and physical fixed-price electricity sales and purchases contracts to reduce its exposure to electricity price volatility.

MidAmerican Energy's total net generating capability accredited by the MISO for the summer of 2016 was 5,066 MW compared to a 2016 summer peak demand of 4,698 MW. Accredited net generating capability represents the amount of generation available to meet the requirements of MidAmerican Energy's retail customers and consists of MidAmerican Energy-owned generation, certain customer "behind the meter" generators and the net amount of capacity purchases and sales. Accredited capacity may vary from the nominal, or design, capacity ratings, particularly for wind turbines whose output is dependent upon wind levels at any given time. Additionally, the actual amount of generating capacity available at any time may be less than the accredited capacity due to regulatory restrictions, transmission constraints, fuel restrictions and generating units being temporarily out of service for inspection, maintenance, refueling, modifications or other reasons. MidAmerican Energy's accredited capability currently exceeds the MISO's minimum requirements.

Transmission and Distribution

MidAmerican Energy's transmission and distribution systems included 3,900 miles of transmission lines in four states, 37,000 miles of distribution lines and 380 substations as of December 31, 2016. Electricity from MidAmerican Energy's generating facilities and purchased electricity is delivered to wholesale markets and its retail customers via the transmission facilities of MidAmerican Energy and others. MidAmerican Energy participates in the MISO energy and ancillary services markets as a transmission-owning member and, accordingly, operates its transmission assets at the direction of the MISO. The MISO manages its energy and ancillary service markets using reliability-constrained economic dispatch of the region's generation. For both the day-ahead and real-time (every five minutes) markets, the MISO analyzes generation commitments to provide market liquidity and transparent pricing while maintaining transmission system reliability by minimizing congestion and maximizing efficient energy transmission. Additionally, through its FERC-approved open access transmission tariff ("OATT"), the MISO performs the role of transmission service provider throughout the MISO footprint and administers the long-term planning function. MISO and related costs of the participants are shared among the participants through a number of mechanisms in accordance with the MISO tariff.

Regulated Natural Gas Operations

MidAmerican Energy is engaged in the procurement, transportation, storage and distribution of natural gas for customers in its service territory. MidAmerican Energy purchases natural gas from various suppliers and contracts with interstate natural gas pipelines for transportation of the gas to MidAmerican Energy's service territory and for storage and balancing services. MidAmerican Energy sells natural gas and delivery services to end-use customers on its distribution system; sells natural gas to other utilities, municipalities and energy marketing companies; and transports natural gas through its distribution system for end-use customers who have independently secured their supply of natural gas. During 2016, 53% of the total natural gas delivered through MidAmerican Energy's distribution system was associated with transportation service.

Natural gas property consists primarily of natural gas mains and services lines, meters, and related distribution equipment, including feeder lines to communities served from natural gas pipelines owned by others. The natural gas distribution facilities of MidAmerican Energy included 23,300 miles of natural gas main and service lines as of December 31, 2016.

Customers

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

	2016	2015	2014
Iowa	76%	76%	77%
South Dakota	13	13	12
Illinois	10	10	10
Nebraska	1	1	1
	100%	100%	100%

The percentages of natural gas sold to MidAmerican Energy's retail and wholesale customers by class of customer, total Dth of natural gas sold, total Dth of transportation service and the average number of retail customers for the years ended December 31 were as follows:

	2016	2015	2014
Residential	41%	42%	49%
Commercial(1)	21	21	24
Industrial(1)	4	5	5
Total retail	66	68	78
Wholesale(2)	34	32	22
	100%	100%	100%
Total Dth of natural gas sold (in thousands)	113,294	110,105	115,209
Total Dth of transportation service (in thousands)	83,610	80,001	82,314
Total average number of retail customers (in thousands)	742	733	726

(1) Commercial and industrial customers are classified primarily based on the nature of their business and natural gas usage. Commercial customers are non-residential customers that use natural gas principally for heating. Industrial customers are non-residential customers that use natural gas principally for their manufacturing processes.

(2) Wholesale sales are generally made to other utilities, municipalities and energy marketing companies for eventual resale to end-use customers.

There are seasonal variations in MidAmerican Energy's regulated natural gas business that are principally due to the use of natural gas for heating. Typically, 50-60% of MidAmerican Energy's regulated natural gas revenue is reported in the months of January, February, March and December.

On January 6, 2014, MidAmerican Energy recorded its all-time highest peak-day delivery through its distribution system of 1,281,767 Dth. This peak-day delivery consisted of 69% traditional retail sales service and 31% transportation service. MidAmerican Energy's 2016/2017 winter heating season peak-day delivery as of February 3, 2017, was 1,096,801 Dth reached on January 5, 2017. This preliminary peak-day delivery included 66% traditional retail sales service and 34% transportation service.

Fuel Supply and Capacity

MidAmerican Energy uses several strategies designed to maintain a reliable natural gas supply and reduce the impact of volatility in natural gas prices on its regulated retail natural gas customers. These strategies include the purchase of a geographically diverse supply portfolio from producers and third party energy marketing companies, the use of leased storage and LNG peaking facilities, and the use of financial derivatives to fix the price on a portion of the anticipated natural gas requirements of MidAmerican Energy's customers. Refer to "General Regulation" in Item 1 of this Form 10-K for a discussion of the purchased gas adjustment clauses ("PGA").

MidAmerican Energy contracts for firm natural gas pipeline capacity to transport natural gas from key production areas and liquid market centers to its service territory through direct interconnects to the pipeline systems of several interstate natural gas pipeline systems, including Northern Natural Gas, an affiliate company. MidAmerican Energy has multiple pipeline interconnections into several larger markets within its distribution system. Multiple pipeline interconnections create competition among pipeline suppliers for transportation capacity to serve those markets, thus reducing costs. In addition, multiple pipeline interconnections increase delivery reliability and give MidAmerican Energy the ability to optimize delivery of the lowest cost supply from the various production areas and liquid market centers into these markets. Benefits to MidAmerican Energy's distribution system customers are shared among all jurisdictions through a consolidated PGA.

At times, the natural gas pipeline capacity available through MidAmerican Energy's firm capacity portfolio may exceed the requirements of retail customers on MidAmerican Energy's distribution system. Firm capacity in excess of MidAmerican Energy's system needs can be resold to other companies to achieve optimum use of the available capacity. Past IUB and South Dakota Public Utilities Commission ("SDPUC") rulings have allowed MidAmerican Energy to retain 30% of the respective jurisdictional revenue on the resold capacity, with the remaining 70% being returned to customers through the PGAs.

MidAmerican Energy utilizes natural gas storage leased from the interstate pipelines to meet retail customer requirements, manage fluctuations in demand due to changes in weather and other usage factors and manage variation in seasonal natural gas pricing. MidAmerican Energy typically withdraws natural gas from storage during the heating season when customer demand is historically at its peak and injects natural gas into storage during off-peak months when customer demand is historically lower than during the heating season. MidAmerican Energy also utilizes its three LNG facilities to meet peak day demands during the winter heating season. The leased storage and LNG facilities reduce MidAmerican Energy's dependence on natural gas purchases during the volatile winter heating season and can deliver a significant portion of MidAmerican Energy's anticipated retail sales requirements on a peak winter day. For MidAmerican Energy's 2016/2017 winter heating season preliminary peak-day of January 5, 2017, supply sources used to meet deliveries to traditional retail sales service customers included 74% from purchases from interstate pipelines, 24% from leased storage and 2% from MidAmerican Energy's LNG facilities.

MidAmerican Energy attempts to optimize the value of its regulated transportation capacity, natural gas supply and leased storage arrangements by engaging in wholesale transactions. IUB and SDPUC rulings have allowed MidAmerican Energy to retain 50% of the respective jurisdictional margins earned on wholesale sales of natural gas, with the remaining 50% being returned to customers through the PGAs.

In 1995, the SDPUC gave initial approval of MidAmerican Energy's Incentive Gas Supply Procurement Plan, which seeks to establish a market-based reference price for key components of MidAmerican Energy's natural gas supply costs. In December 2016, the SDPUC extended the program through October 31, 2019. Under the program, as amended, MidAmerican Energy is required to file with the SDPUC annually a comparison of its actual natural gas procurement costs to the reference price. If MidAmerican Energy's actual natural gas supply costs for the applicable period were less or greater than an established tolerance band around the reference price, then MidAmerican Energy shares a portion of the savings or costs with customers. A similar program was also in effect in Iowa from 1995 through October 31, 2016. Since the implementation of these programs, MidAmerican Energy has successfully achieved savings relative to the applicable reference prices and shared such savings with its regulated retail natural gas customers. MidAmerican Energy's portion of shared savings is reflected in other revenues.

MidAmerican Energy is not aware of any factors that would cause material difficulties in meeting its anticipated retail customer demand for the foreseeable future.

Demand-side Management

MidAmerican Energy has provided a comprehensive set of DSM programs to its Iowa electric and gas customers since 1990 and to customers in its other jurisdictions since 2008. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. Current programs offer services to customers such as energy engineering audits and information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, MidAmerican Energy offers rebates or incentives encouraging the purchase and installation of high-efficiency equipment such as lighting, heating and cooling equipment, weatherization, motors, process equipment and systems, as well as incentives for efficient construction. Incentives are also paid to residential customers who participate in the air conditioner load control program and nonresidential customers who participate in the nonresidential load management program. Although subject to prudence reviews, state regulations allow for contemporaneous recovery of costs incurred for the DSM programs through state-specific energy efficiency service charges paid by all retail electric and gas customers. In 2016, $122 million was expensed for MidAmerican Energy's DSM programs, which resulted in estimated first-year energy savings of 333,000 MWh of electricity and 845,000 Dth of natural gas and an estimated peak load reduction of 414 MW of electricity and 10,130 Dth per day of natural gas.

Employees

As of December 31, 2016, MidAmerican Funding and its subsidiaries had approximately 3,300 employees. As of December 31, 2016, MidAmerican Energy had approximately 3,300 employees, of which approximately 1,400 were covered by union contracts. MidAmerican Energy has three separate contracts with locals of the International Brotherhood of Electrical Workers ("IBEW") and the United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union. A contract with the IBEW covering substantially all of the union employees expires April 30, 2022.

NV ENERGY (NEVADA POWER AND SIERRA PACIFIC)

General

NV Energy, an indirect wholly owned subsidiary of BHE acquired on December 19, 2013, is an energy holding company headquartered in Nevada whose principal subsidiaries are Nevada Power and Sierra Pacific. Nevada Power is a United States regulated electric utility company serving 0.9 million retail customers, including residential, commercial and industrial customers primarily in the Las Vegas, North Las Vegas, Henderson and adjoining areas. Sierra Pacific is a United States regulated electric and natural gas utility company serving 0.3 million retail electric customers, including residential, commercial and industrial customers, and 0.2 million retail and transportation natural gas customers in northern Nevada.

The Nevada Utilities are principally engaged in the business of generating, transmitting, distributing and selling electricity and, in the case of Sierra Pacific, in distributing, selling and transporting natural gas. Nevada Power and Sierra Pacific have electric service territories covering approximately 4,500 square miles and 41,200 square miles, respectively. Sierra Pacific has a natural gas service territory in an area of about 900 square miles in Reno and Sparks. Natural gas property consists primarily of natural gas mains and service lines, meters, and related distribution equipment, including feeder lines to communities served from natural gas pipelines owned by others. The natural gas distribution facilities of Sierra Pacific included 3,300 miles of natural gas mains and service lines as of December 31, 2016.

The Nevada Utilities also buy and sell electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants to balance and optimize the economic benefits of electricity generation, retail customer loads and existing wholesale transactions. The Nevada Utilities are subject to comprehensive state and federal regulation. Regulated electric utility operation is Nevada Power's only segment while regulated electric utility operations and regulated natural gas operations are the two segments of Sierra Pacific. Principal industries served by the Nevada Utilities include gaming, recreation, warehousing, manufacturing and governmental. Sierra Pacific also serves the mining industry. In addition to the Nevada Utilities electric retail sales and Sierra Pacific's natural gas transportation, the Nevada Utilities sell electricity and natural gas to other utilities, municipalities and energy marketing companies on a wholesale basis.

Nevada Power's principal executive offices are located at 6226 West Sahara Avenue, Las Vegas, Nevada 89146, and its telephone number is (702) 402-5000. Nevada Power was incorporated in 1929 under the laws of the state of Nevada.

Sierra Pacific's principal executive offices are located at 6100 Neil Road, Reno, Nevada 89511, and its telephone number is (775) 834-4011. Sierra Pacific was incorporated in 1912 under the laws of the state of Nevada.

Regulated Operations

The Nevada Utilities deliver electricity and, in the case of Sierra Pacific, natural gas to customers in Nevada. The Nevada Utilities own facilities or have power purchase contracts for coal, natural gas, water, wind, solar, geothermal, biomass and waste heat resources to provide electricity. This electricity, together with electricity purchased on the wholesale market, is then transmitted via a grid of transmission lines, which are part of the Western Interconnection, a regional grid in the United States. The Western Interconnection includes the interconnected transmission systems of 14 western states, two Canadian provinces and parts of Mexico. The electricity is then transformed to lower voltages and delivered to customers through the Nevada Utilities' distribution system.

The Nevada Utilities seek to manage growth in their customer demand through the construction and purchase of cost-effective, environmentally prudent and efficient sources of electricity supply and through energy efficiency programs. The Nevada Utilities participate in an EIM operated by the California ISO, which reduces costs to serve customers through more efficient dispatch of a larger and more diverse pool of resources, more effectively integrates renewables and enhances reliability through improved situational awareness and responsiveness.

The Nevada Utilities operate under certificates of public convenience and necessity as regulated by the PUCN, and as such the Nevada Utilities have an obligation to provide electricity service to those customers within their service territory. In return, the PUCN has established rates on a cost-of-service basis, which are designed to allow the Nevada Utilities an opportunity to recover all prudently incurred costs of providing services and an opportunity to earn a reasonable return on their investment.

The Nevada Utilities' electric and natural gas operations are conducted under numerous nonexclusive franchise agreements, revocable permits and licenses obtained from federal, state and local authorities. The expiration of these franchise agreements ranges from 2020 through 2032 for Nevada Power and 2017 through 2049 for Sierra Pacific.

The percentages of Sierra Pacific's operating revenue and operating income derived from the following business activities for the years ended December 31 were as follows:

	2016	2015	2014
Operating revenue:			
Electric	86%	86%	86%
Gas	14	14	14
	100%	100%	100%
Operating income:			
Electric	89%	91%	93%
Gas	11	9	7
	100%	100%	100%

Regulated Electric Operations

Customers

Electricity sold to the Nevada Utilities' retail and wholesale customers by class of customer and the average number of retail customers for the years ended December 31 were as follows:

	2016		2015		2014	
Nevada Power:						
GWh sold:						
Residential	9,394	43%	9,246	42%	8,923	42%
Commercial	4,663	21	4,635	21	4,489	21
Industrial	7,313	34	7,571	34	7,486	36
Other	212	1	214	1	211	1
Total retail	21,582	99	21,666	98	21,109	100
Wholesale	258	1	353	2	20	—
Total GWh sold	21,840	100%	22,019	100%	21,129	100%
Average number of retail customers (in thousands):						
Residential	796	88%	782	88%	770	88%
Commercial	105	12	104	12	102	12
Industrial	2	—	2	—	2	—
Total	903	100%	888	100%	874	100%
Sierra Pacific:						
GWh sold:						
Residential	2,375	26%	2,315	26%	2,268	26%
Commercial	2,933	33	2,942	33	2,944	34
Industrial	3,014	34	2,973	34	2,869	33
Other	16	—	16	—	16	—
Total retail	8,338	93	8,246	93	8,097	93
Wholesale	662	7	664	7	645	7
Total GWh sold	9,000	100%	8,910	100%	8,742	100%
Average number of retail customers (in thousands):						
Residential	291	86%	288	86%	285	86%
Commercial	47	14	46	14	46	14
Total	338	100%	334	100%	331	100%

Customer Usage and Seasonality

In addition to the variations in weather from year to year, fluctuations in economic conditions within the Nevada Utilities' service territory and elsewhere can impact customer usage, particularly for gaming, mining and wholesale customers. Wholesale sales are impacted by market prices for energy relative to the incremental cost to generate power.

There are seasonal variations in the Nevada Utilities' electric business that are principally related to weather and the related use of electricity for air conditioning. Typically, 46-50% of Nevada Power's and 35-38% of Sierra Pacific's regulated electric revenue is reported in the months of June, July, August and September.

The annual hourly peak customer demand on the Nevada Utilities' electric systems occurs as a result of air conditioning use during the cooling season. Peak demand represents the highest demand on a given day and at a given hour. On July 28, 2016, customer usage of electricity caused a record hourly peak demand of 6,124 MW on Nevada Power's electric system. On July 28, 2016, customer usage of electricity caused a record hourly peak demand of 1,842 MW on Sierra Pacific's electric system.

Generating Facilities and Fuel Supply

The Nevada Utilities have ownership interest in a diverse portfolio of generating facilities. The following table presents certain information regarding the Nevada Utilities' owned generating facilities as of December 31, 2016:

Generating Facility	Location	Energy Source	Installed	Facility Net Capacity (MW)(1)	Net Owned Capacity (MW)(1)
Nevada Power:					
NATURAL GAS:					
Clark	Las Vegas, NV	Natural gas	1973-2008	1,102	1,102
Lenzie	Las Vegas, NV	Natural gas	2006	1,102	1,102
Harry Allen	Las Vegas, NV	Natural gas	1995-2011	628	628
Higgins	Primm, NV	Natural gas	2004	530	530
Silverhawk(2)	Las Vegas, NV	Natural gas	2004	520	390
Las Vegas	Las Vegas, NV	Natural gas	1994-2003	272	272
Sun Peak	Las Vegas, NV	Natural gas/oil	1991	210	210
				4,364	4,234
COAL:					
Reid Gardner Unit No. 4(3)	Moapa, NV	Coal	1983	257	257
Navajo Unit Nos. 1, 2 and 3(3)	Page, AZ	Coal	1974-1976	2,250	255
				2,507	512
RENEWABLES:					
Goodsprings	Goodsprings, NV	Waste heat	2010	5	5
Nellis	Las Vegas, NV	Solar	2015	15	15
				20	20
Total Nevada Power				6,891	4,766
Sierra Pacific:					
NATURAL GAS:					
Tracy	Sparks, NV	Natural gas	1974-2008	753	753
Ft. Churchill	Yerington, NV	Natural gas	1968-1971	226	226
Clark Mountain	Sparks, NV	Natural gas	1994	132	132
				1,111	1,111
COAL:					
Valmy Unit Nos. 1 and 2	Valmy, NV	Coal	1981-1985	522	261
Total Sierra Pacific				1,633	1,372
Total NV Energy				8,524	6,138

(1) Facility Net Capacity represents the lesser of nominal ratings or any limitations under applicable interconnection, power purchase, or other agreements for intermittent resources and the total net dependable capability available during summer conditions for all other units. An intermittent resource's nominal rating is the manufacturer's contractually specified capability (in MW) under specified conditions. Net Owned Capacity indicates Nevada Power or Sierra Pacific's ownership of Facility Net Capacity.

(2) Nevada Power plans to acquire the remaining 25% (130 MW) of Silverhawk in April 2017.

(3) Nevada Power currently anticipates retiring Reid Gardner Unit No. 4 in the first quarter of 2017 and eliminating its interest in Navajo Unit Nos. 1, 2 and 3 in 2019. Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion.

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

	2016	2015	2014
Nevada Power:			
Natural gas	64%	65%	56%
Coal	7	7	20
Total energy generated	71	72	76
Energy purchased - long-term contracts (non-renewable)	14	15	13
Energy purchased - long-term contracts (renewable)(1)	14	12	10
Energy purchased - short-term contracts and other	1	1	1
	100%	100%	100%
Sierra Pacific:			
Natural gas	45%	41%	46%
Coal	8	13	21
Total energy generated	53	54	67
Energy purchased - long-term contracts (non-renewable)	36	36	22
Energy purchased - long-term contracts (renewable)(1)	10	9	10
Energy purchased - short-term contracts and other	1	1	1
	100%	100%	100%

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

The Nevada Utilities are required to have resources available to continuously meet their customer needs. The percentage of the Nevada Utilities' energy supplied by energy source varies from year-to-year and is subject to numerous operational and economic factors such as planned and unplanned outages; fuel commodity prices; fuel transportation costs; weather; environmental considerations; transmission constraints; and wholesale market prices of electricity. The Nevada Utilities evaluate these factors continuously in order to facilitate economical dispatch of their generating facilities. When factors for one energy source are less favorable, the Nevada Utilities place more reliance on other energy sources. As long as the Nevada Utilities' purchases are deemed prudent by the PUCN, through their annual prudency review, the Nevada Utilities are permitted to recover the cost of fuel and purchased power. The Nevada Utilities also have the ability to reset quarterly BTER, with PUCN approval, based on the last twelve months fuel costs and purchased power and to reset quarterly DEAA.

In response to these energy supply challenges, the Nevada Utilities have adopted an approach to managing the energy supply function that has three primary elements. The first element is a set of management guidelines to procuring and optimizing the supply portfolio that is consistent with the requirements of a load serving entity with a full requirements obligation, and with the growth of private generation serving a small but growing group of customers with partial requirements. The second element is an energy risk management and risk control approach that ensures clear separation of roles between the day-to-day management of risks and compliance monitoring and control and ensures clear distinction between policy setting (or planning) and execution. Lastly, the Nevada Utilities pursue a process of ongoing regulatory involvement and acknowledgment of the resource portfolio management plans.

The Nevada Utilities have entered into multiple long-term power purchase contracts (three or more years) with suppliers that generate electricity utilizing coal, natural gas and renewable resources. Nevada Power has entered into contracts with a total capacity of 2,217 MW with contract termination dates ranging from 2017 to 2040. Included in these contracts are 1,257 MW of capacity of renewable energy, of which 228 MW of capacity are under development or construction and not currently available. Sierra Pacific has entered into contracts with a total capacity of 508 MW with contract termination dates ranging from 2017 to 2040. Included in these contracts are 311 MW of capacity of renewable energy, of which 101 MW of capacity are under development or construction and not currently available. In December 2016, the PUCN approved a settlement with Switch, Ltd. allowing it to purchase energy from alternative providers of a new electric resource and become a distribution only service customer prior to August 2017. The settlement provides that Nevada Power and Sierra Pacific will assign to Switch, Ltd. power purchase contracts of 28 MW and 51 MW, respectively, for renewable energy currently under construction if all parties involved reach an agreement.

The Nevada Utilities manage certain risks relating to their supply of electricity and fuel requirements by entering into various contracts, which may be accounted for as derivatives, including forwards, futures, options, swaps and other agreements. Refer to NV Energy's "General Regulation" section in Item 1 of this Form 10-K for a discussion of energy cost recovery by jurisdiction and Nevada Power's Item 7A and Sierra Pacific's Item 7A in this Form 10-K for a discussion of commodity price risk and derivative contracts.

Natural Gas

The Nevada Utilities rely on first-of-the-month indexed physical gas purchases for the majority of natural gas needed to operate their generating facilities. To secure natural gas supplies for the generating facilities, the Nevada Utilities execute purchases pursuant to a PUCN approved four season laddering strategy. In 2016, natural gas supply net purchases averaged 356,795 and 133,921 Dth per day with the winter period contracts averaging 312,271 and 156,841 Dth per day and the summer period contracts averaging 388,419 and 117,642 Dth per day for Nevada Power and Sierra Pacific, respectively. The Nevada Utilities believe supplies from these sources are presently adequate and available to meet its needs.

The Nevada Utilities contract for firm natural gas pipeline capacity to transport natural gas from production areas to their service territory through direct interconnects to the pipeline systems of several interstate natural gas pipeline systems, including Nevada Power who contracts with Kern River, an affiliated company. Sierra Pacific utilizes natural gas storage leased from interstate pipelines to meet retail customer requirements and to manage the daily changes in demand due to changes in weather and other usage factors. The stored natural gas is typically replaced during off-peak months when the demand for natural gas is historically lower than during the heating season.

Coal

Other than the agreement mentioned below for the Navajo Generating Station, the Nevada Utilities have no commitments to purchase coal for 2017 or beyond and will rely on spot market solicitations for any coal supplies needed during 2017 and will regularly monitor the western coal market for opportunities to meet these needs. Nevada Power's coal supply plan has the overall goal of eliminating Reid Gardner Unit No. 4's coal pile by its expected retirement date in the first quarter of 2017. The Nevada Utilities have transportation services contracts with Union Pacific Railroad Company to ship coal from various origins in Central Utah, Western Colorado and Wyoming that expire December 31, 2017 for Nevada Power and December 31, 2019 for Sierra Pacific. The Navajo Generating Station, jointly owned by Nevada Power along with other entities and operated by Salt River Project, has a coal purchase agreement that extends through December 2019.

Transmission and Distribution

The Nevada Utilities' transmission system is part of the Western Interconnection. The Nevada Utilities' transmission system, together with contractual rights on other transmission systems, enables the Nevada Utilities to integrate and access generation resources to meet their customer load requirements. Nevada Power's transmission and distribution systems included approximately 2,000 miles of transmission lines, 24,700 miles of distribution lines and 200 substations as of December 31, 2016. Sierra Pacific's transmission and distribution systems included approximately 2,300 miles of transmission lines, 17,700 miles of distribution lines and 200 substations as of December 31, 2016.

ON Line is a 231 mile, 500-kV transmission line connecting Nevada Power's and Sierra Pacific's service territories. ON Line provides the ability to jointly dispatch energy throughout Nevada and provide access to renewable energy resources in parts of northern and eastern Nevada, which enhances the Nevada Utilities' ability to manage and optimize their generating facilities. ON Line provides between 600 and 800 MW of transfer capability with interconnection between the Robinson Summit substation on the Sierra Pacific system and the Harry Allen substation on the Nevada Power system. ON Line was a joint project between the Nevada Utilities and Great Basin Transmission, LLC. The Nevada Utilities own a 25% interest in ON Line and have entered into a long-term transmission use agreement with Great Basin Transmission, LLC for its 75% interest in ON Line until 2054. The Nevada Utilities share of its 25% interest in ON Line and the long-term transmission use agreement is split 95% for Nevada Power and 5% for Sierra Pacific.

The Nevada Utilities participate in the EIM operated by the California ISO. The EIM expands the real-time component of the California ISO to optimize and balance electricity supply and demand every five minutes across the EIM footprint. The EIM is voluntary and available to all balancing authorities in the Western United States. EIM market participants submit bids to the California ISO market operator before each hour for each generating resource they choose to be dispatched by the market. Each bid is comprised of a dispatchable operating range, ramp rate and prices across the operating range. The California ISO market operator uses sophisticated technology to select the least-cost resources to meet demand and send simultaneous dispatch signals to every participating generator across the EIM footprint every five minutes. In addition to generation resource bids, the California ISO market operator also receives continuous real-time updates of the transmission grid network, meteorological and load forecast information that it uses to optimize dispatch instructions. Outside the EIM footprint, utilities in the Western United States do not utilize comparable technology and are largely limited to transactions within the borders of their balancing authority area to balance supply and demand intra-hour using a combination of manual and automated dispatch. The EIM delivers customer benefits by leveraging automation, geographic and resource diversity to result in more efficient dispatch, more effective integration of renewables and improved situational awareness. Benefits to customers are expected to increase with renewable resource expansion and as more entities join the EIM bringing incremental diversity.

Future Generation

The Nevada Utilities file IRPs every three years, and as necessary, may file amendments to their IRPs. IRPs are prepared in compliance with Nevada laws and regulations and cover a 20-year period. IRPs develop a comprehensive, integrated plan that considers customer energy requirements and propose the resources to meet those requirements in a manner that is consistent with prevailing market fundamentals. The ultimate goal of the IRPs is to balance the objectives of minimizing costs and reducing volatility while reliably meeting the electric needs of Nevada Power's and Sierra Pacific's customers. Costs incurred to complete projects approved through the IRP process still remain subject to review for reasonableness by the PUCN.

In July 2015, Nevada Power filed its triennial IRP and in December 2015, Nevada Power received PUCN approval. Nevada Power filed an amended IRP in August 2016 and received PUCN approval in December 2016. Sierra Pacific filed its triennial IRP in July 2016 and in December 2016, Sierra Pacific received PUCN approval. As a part of the filings, the Nevada Utilities sought PUCN authorization to acquire the South Point Energy Center, a 504-MW combined-cycle generating facility located in Arizona. In December 2016, the PUCN denied the acquisition of this facility. In January 2017, Nevada Power filed a petition for reconsideration relating to the acquisition of South Point Energy Center. In February 2017, the PUCN affirmed the denial of the acquisition of South Point Energy Center.

There is the potential for continued price volatility in the Nevada Utilities' service territories, particularly during peak periods. Too great of a dependence on generation from the wholesale market can lead to power price volatilities depending on available power supply and prevailing natural gas prices. The Nevada Utilities face load obligation uncertainty due to the potential for customer switching. Some counterparties in these areas have significant credit difficulties, representing credit risk to the Nevada Utilities. Finally, the Nevada Utilities' own credit situation can have an impact on its ability to enter into transactions.

Within the energy supply planning process, there are three key components covering different time frames:

- The PUCN-approved long-term IRP which is filed every three years and has a 20-year planning horizon;
- The PUCN-approved energy supply plan which is an intermediate term resource procurement and risk management plan that establishes the supply portfolio strategies within which intermediate term resource requirements will be met and has a one to three year planning horizon; and
- Tactical execution activities with a one-month to twelve-month focus.

The energy supply plan operates in conjunction with the PUCN-approved 20-year IRP. It serves as a guide for near-term execution and fulfillment of energy needs. When the energy supply plan calls for executing contracts of longer than three years, PUCN approval is required.

Energy-Efficiency Programs

The Nevada Utilities have provided a comprehensive set of energy efficiency, demand response and conservation programs to their Nevada electric customers. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. Current programs offer services to customers such as energy audits and customer education and awareness efforts that provide information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, the Nevada Utilities have offered rebates or incentives encouraging the purchase and installation of high-efficiency equipment such as lighting, heating and cooling equipment, weatherization, motors, process equipment and systems, as well as incentives for efficient construction. Incentives are also paid to residential customers who participate in the air conditioner load control program and nonresidential customers who participate in the nonresidential load management program. Energy efficiency program costs are recovered through annual rates set by the PUCN, and adjusted based on the Nevada Utilities' annual filing to recover current program costs and any over or under collections from the prior filing, subject to prudence review. During 2016, Nevada Power spent $38 million on energy efficiency programs, resulting in an estimated 173,942 MWh of electric energy savings and an estimated 219 MW of electric peak load management. During 2016, Sierra Pacific spent $11 million on energy efficiency programs, resulting in an estimated 60,825 MWh of electric energy savings and an estimated 12 MW of electric peak load management.

Regulated Natural Gas Operations

Sierra Pacific is engaged in the procurement, transportation and distribution of natural gas for customers in its service territory. Sierra Pacific purchases natural gas from various suppliers and contracts with interstate natural gas pipelines for transportation of the natural gas from the production areas to Sierra Pacific's service territory and for storage services to manage fluctuations in system demand and seasonal pricing. Sierra Pacific sells natural gas and delivery services to end-use customers on its distribution system; sells natural gas to other utilities, municipalities and energy marketing companies; and transports natural gas through its distribution system for a number of end-use customers who have independently secured their supply of natural gas. During 2016, 11% of the total natural gas delivered through Sierra Pacific's distribution system was for transportation service.

Customers

The percentages of natural gas sold to Sierra Pacific's retail and wholesale customers by class of customer, total Dth of natural gas sold, total Dth of transportation service and the average number of retail customers for the years ended December 31 were as follows:

	2016	**2015**	**2014**
Residential	52%	49%	51%
Commercial(1)	26	24	25
Industrial(1)	9	8	9
Total retail	87	81	85
Wholesale	13	19	15
	100%	100%	100%
Total Dth of natural gas sold (in thousands)	17,677	17,600	15,519
Total Dth of transportation service (in thousands)	2,256	2,288	2,275
Total average number of retail customers (in thousands)	163	159	156

(1) Commercial and industrial customers are classified primarily based on their natural gas usage. Commercial customers are non-residential customers with monthly gas usage less than 12,000 therms during five consecutive winter months. Industrial customers are non-residential customers that use natural gas in excess of 12,000 therms during one or more winter months.

There are seasonal variations in Sierra Pacific's regulated natural gas business that are principally due to the use of natural gas for heating. Typically, 50-60% of Sierra Pacific's regulated natural gas revenue is reported in the months of January, February, March and December.

On January 1, 2016, Sierra Pacific recorded its highest peak-day natural gas delivery of 151,184 Dth, which is 12,390 Dth less than the record peak-day delivery of 163,574 Dth set on December 9, 2013. This peak-day delivery consisted of 93% traditional retail sales service and 7% transportation service.

Fuel Supply and Capacity

The purchase of natural gas for Sierra Pacific's regulated natural gas operations is done in combination with the purchase of natural gas for Sierra Pacific's regulated electric operations. In response to energy supply challenges, Sierra Pacific has adopted an approach to managing the energy supply function that has three primary elements, as discussed earlier under Generating Facilities and Fuel Supply. Similar to Sierra Pacific's regulated electric operations, as long as Sierra Pacific's purchases of natural gas are deemed prudent by the PUCN, through its annual prudency review, Sierra Pacific is permitted to recover the cost of natural gas. Sierra Pacific also has the ability to reset quarterly BTER, with PUCN approval, based on the last twelve months fuel costs and to reset quarterly DEAA.

Employees

As of December 31, 2016, Nevada Power had approximately 1,400 employees, of which approximately 700 were covered by a collective bargaining agreement with the International Brotherhood of Electrical Workers.

As of December 31, 2016, Sierra Pacific had approximately 1,000 employees, of which approximately 500 were covered by a collective bargaining agreement with the International Brotherhood of Electrical Workers.

NORTHERN POWERGRID

Northern Powergrid, an indirect wholly owned subsidiary of BHE, is a holding company which owns two companies that distribute electricity in Great Britain, Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc. In addition to the Northern Powergrid Distribution Companies, Northern Powergrid also owns a meter asset rental business that leases smart meters to energy suppliers in the United Kingdom and Ireland, an engineering contracting business that provides electrical infrastructure contracting services primarily to third parties and a hydrocarbon exploration and development business that is focused on developing integrated upstream gas projects in Europe and Australia.

The Northern Powergrid Distribution Companies serve 3.9 million end-users and operate in the north-east of England from North Northumberland through Tyne and Wear, County Durham and Yorkshire to North Lincolnshire, an area covering 10,000 square miles. The principal function of the Northern Powergrid Distribution Companies is to build, maintain and operate the electricity distribution network through which the end-user receives a supply of electricity.

The Northern Powergrid Distribution Companies receive electricity from the national grid transmission system and from generators that are directly connected to the distribution network and distribute it to end-users' premises using their networks of transformers, switchgear and distribution lines and cables. Substantially all of the end-users in the Northern Powergrid Distribution Companies' distribution service areas are directly or indirectly connected to the Northern Powergrid Distribution Companies' networks and electricity can only be delivered to these end-users through their distribution systems, thus providing the Northern Powergrid Distribution Companies with distribution volumes that are relatively stable from year to year. The Northern Powergrid Distribution Companies charge fees for the use of their distribution systems to the suppliers of electricity.

The suppliers purchase electricity from generators, sell the electricity to end-user customers and use the Northern Powergrid Distribution Companies' distribution networks pursuant to an industry standard "Distribution Connection and Use of System Agreement." One supplier, RWE Npower PLC and certain of its affiliates, represented 22% of the total combined distribution revenue of the Northern Powergrid Distribution Companies during 2016. Variations in demand from end-users can affect the revenues that are received by the Northern Powergrid Distribution Companies in any year, but such variations have no effect on the total revenue that the Northern Powergrid Distribution Companies are allowed to recover in a price control period. Under- or over-recoveries against price-controlled revenues are carried forward into prices for future years.

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

The price controlled revenue of the regulated distribution companies is set out in the special conditions of the licenses of those companies. The licenses are enforced by the regulator, the Gas and Electricity Markets Authority through its office of gas and electric markets (known as "Ofgem") and limit increases to allowed revenues (or may require decreases) based upon the rate of inflation, other specified factors and other regulatory action. Changes to the price controls can be made by the regulator, but if a licensee disagrees with a change to its license it can appeal the matter to the United Kingdom's Competition and Markets Authority. It has been the convention in Great Britain for regulators to conduct periodic regulatory reviews before making proposals for any changes to the price controls. The current electricity distribution price control became effective April 1, 2015 and is expected to continue through March 31, 2023. Following initial submission of the Northern Powergrid Distribution Companies' business plans for the current price control period to Ofgem in July 2013 and resubmission, following feedback from Ofgem in March 2014, the final determinations for the current price control were published in November 2014. In March 2015 Northern Powergrid was the only electricity distributor to appeal Ofgem's price control decision and in September 2015 the appeal authority allowed part of the appeal, awarding an additional £30 million (in 2012/13 prices) in expenditure allowances.

GWh and percentages of electricity distributed to the Northern Powergrid Distribution Companies' end-users and the total number of end-users as of and for the years ended December 31 were as follows:

	2016		2015		2014	
Northern Powergrid (Northeast) Limited:						
Residential	5,227	36%	5,144	34%	5,161	34%
Commercial	2,222	15%	2,417	16	2,393	16
Industrial	6,963	48%	7,160	48	7,181	48
Other	214	1%	231	2	262	2
	14,626	100%	14,952	100%	14,997	100%
Northern Powergrid (Yorkshire) plc:						
Residential	7,612	36%	7,574	35%	7,481	35%
Commercial	3,116	15%	3,352	16	3,347	16
Industrial	10,275	48%	10,403	48	10,486	48
Other	290	1%	299	1	322	1
	21,293	100%	21,628	100%	21,636	100%
Total electricity distributed	35,919		36,580		36,633	
Number of end-users (in thousands):						
Northern Powergrid (Northeast) Limited	1,602		1,597		1,593	
Northern Powergrid (Yorkshire) plc	2,301		2,294		2,286	
	3,903		3,891		3,879	

As of December 31, 2016, the Northern Powergrid Distribution Companies' combined electricity distribution network included 18,000 miles of overhead lines, 42,000 miles of underground cables and 750 major substations.

BHE PIPELINE GROUP

The BHE Pipeline Group consists of BHE's interstate natural gas pipeline companies, Northern Natural Gas and Kern River.

Northern Natural Gas

Northern Natural Gas, an indirect wholly owned subsidiary of BHE, owns the largest interstate natural gas pipeline system in the United States, as measured by pipeline miles, which reaches from west Texas to Michigan's Upper Peninsula. Northern Natural Gas primarily transports and stores natural gas for utilities, municipalities, gas marketing companies-and industrial and commercial users. Northern Natural Gas' pipeline system consists of two commercial segments. Its traditional end-use and distribution market area in the northern part of its system, referred to as the Market Area, includes points in Iowa, Nebraska, Minnesota, Wisconsin, South Dakota, Michigan and Illinois. Its natural gas supply and delivery service area in the southern part of its system, referred to as the Field Area, includes points in Kansas, Texas, Oklahoma and New Mexico. Northern Natural Gas' pipeline system consists of 14,700 miles of natural gas pipelines, including 6,300 miles of mainline transmission pipelines and 8,400 miles of branch and lateral pipelines, with a Market Area design capacity of 5.8 Bcf per day, a Field Area delivery capacity of 1.7 Bcf per day to the Market Area and 1.1 Bcf per day to the West Texas area and over 73 Bcf of firm service and operational storage cycle capacity in five storage facilities. Northern Natural Gas' pipeline system is configured with approximately 2,300 active receipt and delivery points which are integrated with the facilities of LDCs. Many of Northern Natural Gas' LDC customers are part of combined utilities that also use natural gas as a fuel source for electric generation. Northern Natural Gas delivers over 1.0 Trillion Cubic Feet ("Tcf") of natural gas to its customers annually.

Northern Natural Gas' transportation rates and most of its storage rates are cost-based. These rates are designed to provide Northern Natural Gas with an opportunity to recover its costs of providing services and earn a reasonable return on its investments. In addition, Northern Natural Gas has fixed rates that are market-based for certain of its firm storage contracts with contract terms that expire in 2028.

Northern Natural Gas' operating revenue for the years ended December 31 was as follows (in millions):

	2016		2015		2014	
Transportation:						
Market Area	$ 492	77%	$ 474	72%	$ 457	63%
Field Area	64	10	84	13	100	14
Total transportation	556	87	558	85	557	77
Storage	69	11	62	9	61	8
Total transportation and storage revenue	625	98	620	94	618	96
Gas, liquids and other sales	11	2	36	6	106	4
Total operating revenue	$ 636	100%	$ 656	100%	$ 724	100%

Substantially all of Northern Natural Gas' Market Area transportation revenue is generated from reservation charges, with the balance from usage charges. Northern Natural Gas transports natural gas primarily to local distribution markets and end-users in the Market Area. Northern Natural Gas provides service to 81 utilities, including MidAmerican Energy, an affiliate company, which serve numerous residential, commercial and industrial customers. Most of Northern Natural Gas' transportation capacity in the Market Area is committed to customers under firm transportation contracts, where customers pay Northern Natural Gas a monthly reservation charge for the right to transport natural gas through Northern Natural Gas' system. Reservation charges are required to be paid regardless of volumes transported or stored. As of December 31, 2016, approximately 72% of Northern Natural Gas' customers' entitlement in the Market Area have terms beyond 2018 and over 41% beyond 2019. As of December 31, 2016, the weighted average remaining contract term for Northern Natural Gas' Market Area firm transportation contracts is approximately five years.

Northern Natural Gas' Field Area customers consist primarily of energy marketing companies and midstream companies, which take advantage of the price spread opportunities created between Field Area supply points and the Field-Market Demarcation Point. In addition, there are a growing number of midstream customers that are delivering gas south in the Field Area to the Waha Hub market. The remaining Field Area transportation service is sold to power generators connected to Northern Natural Gas' system in Texas and New Mexico that are contracted on a long-term basis with terms that extend to at least 2020, and various LDCs, energy marketing companies and midstream companies for both connected and off-system markets.

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

Northern Natural Gas has 59.3 Bcf of firm storage contracts with its cost-based and market-based services. Firm storage contracts with cost-based rates, representing 51.3 Bcf, have an average remaining contract term of six years and are contracted at maximum tariff rates. The remaining firm storage contracts with market-based rates, representing 8.0 Bcf, have an average remaining contract term of eleven years.

Except for quantities of natural gas owned and managed for operational and system balancing purposes, Northern Natural Gas does not own the natural gas that is transported through its system. The sale of natural gas for operational and system balancing purposes accounts for the majority of the remaining operating revenue.

During 2016, Northern Natural Gas had three customers, including MidAmerican Energy, that each accounted for greater than 10% of its transportation and storage revenue and its ten largest customers accounted for 67% of its system-wide transportation and storage revenue. Northern Natural Gas has agreements with terms from 2017 to 2027 to retain its three largest customers' volumes. The loss of any of these significant customers, if not replaced, could have a material adverse effect on Northern Natural Gas.

Northern Natural Gas' extensive pipeline system, which is interconnected with many interstate and intrastate pipelines in the national grid system, has access to multiple major supply basins. Direct access is available from producers in the Anadarko, Permian and Hugoton basins, some of which have recently experienced increased production from shale and tight sands formations adjacent to Northern Natural Gas' pipeline. Since 2011, the pipeline has connected 1,705,000 Dth per day of supply access from the Wolfberry shale formation in west Texas and from the Granite Wash tight sands formations in the Texas panhandle and in Oklahoma. Additionally, Northern Natural Gas has interconnections with several interstate pipelines and several intrastate pipelines with receipt, delivery, or bi-directional capabilities. Because of Northern Natural Gas' location and multiple interconnections it is able to access natural gas from other key production areas, such as the Rocky Mountain and western Canadian basins. The Rocky Mountain basins are accessed through interconnects with Trailblazer Pipeline Company, Tallgrass Interstate Gas Transmission, LLC, Cheyenne Plains Gas Pipeline Company, LLC, Colorado Interstate Gas Company and Rockies Express Pipeline, LLC ("REX"). The western Canadian basins are accessed through interconnects with Northern Border Pipeline Company ("Northern Border"), Great Lakes Gas Transmission Limited Partnership ("Great Lakes") and Viking Gas Transmission Company ("Viking"). This supply diversity and access to both stable and growing production areas provides significant flexibility to Northern Natural Gas' system and customers.

Northern Natural Gas' system experiences significant seasonal swings in demand and revenue, with the highest demand and revenues typically occurring during the months of November through March. This seasonality provides Northern Natural Gas with opportunities to deliver additional value-added services, such as firm and interruptible storage services. As a result of Northern Natural Gas' geographic location in the middle of the United States and its many interconnections with other pipelines, Northern Natural Gas has the opportunity to augment its steady end user and LDC revenue by capitalizing on opportunities for shippers to reach additional markets, such as Chicago, Illinois, other parts of the Midwest, and Texas, through interconnects.

Kern River

Kern River, an indirect wholly owned subsidiary of BHE, owns an interstate natural gas pipeline system that extends from supply areas in the Rocky Mountains to consuming markets in Utah, Nevada and California. Kern River provided 20% of California's demand for natural gas in 2015. Kern River's pipeline system consists of 1,700 miles of natural gas pipelines, including 1,400 miles of mainline section and 300 miles of common facilities, with a design capacity of 2,166,575 Dth per day. Kern River owns the entire mainline section, which extends from the system's point of origination near Opal, Wyoming, through the Central Rocky Mountains area into Daggett, California. The mainline section consists of 1,300 miles of 36-inch diameter pipeline and 100 miles of various laterals that connect to the mainline. The common facilities are jointly owned by Kern River and Mojave Pipeline Company ("Mojave") as tenants-in-common. Except for quantities of natural gas owned for operational purposes, Kern River does not own the natural gas that is transported through its system. Kern River's transportation rates are cost-based. The rates are designed to provide Kern River with an opportunity to recover its costs of providing services and earn a reasonable return on its investments.

Approximately 90% of Kern River's design capacity of 2,166,575 Dth per day is contracted pursuant to long-term firm natural gas transportation service agreements, whereby Kern River receives natural gas on behalf of customers at designated receipt points and transports the natural gas on a firm basis to designated delivery points. In return for this service, each customer pays Kern River a fixed monthly reservation fee based on each customer's maximum daily quantity, which represents 96% of total operating revenue, and a commodity charge based on the actual amount of natural gas transported pursuant to its long-term firm natural gas transportation service agreements and Kern River's tariff.

These long-term firm natural gas transportation service agreements expire between March 2018 and April 2033 and have a weighted-average remaining contract term of over eight years. Kern River's customers include electric and natural gas distribution utilities, major oil and natural gas companies or affiliates of such companies, electric generating companies, energy marketing and trading companies and financial institutions. As of December 31, 2016, nearly 79% of the firm capacity under contract has primary delivery points in California, with the flexibility to access secondary delivery points in Nevada and Utah.

During 2016, Kern River had one customer, Nevada Power Company, an affiliate company, who accounted for greater than 10% of its revenue. The loss of this significant customer, if not replaced, could have a material adverse effect on Kern River.

Competition

The Pipeline Companies compete with other pipelines on the basis of cost, flexibility, reliability of service and overall customer service, with the end-user's decision being made primarily on the basis of delivered price, which includes both the natural gas commodity cost and its transportation cost. Natural gas also competes with alternative energy sources, including coal, nuclear energy, wind, geothermal, solar and fuel oil. Legislation and governmental regulations, the weather, the futures market, production costs and other factors beyond the control of the Pipeline Companies influence the price of the natural gas commodity.

The natural gas industry is undergoing a significant shift in supply sources. Production from conventional sources continues to decline while production from unconventional sources, such as shale gas, is increasing. This shift will affect the supply patterns, the flows, the locational and seasonal natural gas price spreads and rates that can be charged on pipeline systems. The impact will vary among pipelines according to the location and the number of competitors attached to these new supply sources.

Electric power generation has been the source of most of the growth in demand for natural gas over the last 10 years, and this trend is expected to continue in the future. The growth of natural gas in this sector is influenced by regulation, new sources of natural gas, competition with other energy sources, primarily coal and renewables, and increased consumption of electricity as a result of economic growth. Short-term market shifts have been driven by relative costs of coal-fueled generation versus natural gas-fueled generation. A long-term market shift away from the use of coal in power generation could be driven by environmental regulations. The future demand for natural gas could be increased by regulations limiting or discouraging coal use. However, natural gas demand could potentially be adversely affected by laws mandating or encouraging renewable power sources that produce fewer GHG emissions than natural gas.

The Pipeline Companies' ability to extend existing customer contracts, remarket expiring contracted capacity or market new capacity is dependent on competitive alternatives, the regulatory environment and the market supply and demand factors at the relevant dates these contracts are eligible to be renewed or extended. The duration of new or renegotiated contracts will be affected by current commodity and transportation prices, competitive conditions and customers' judgments concerning future market trends and volatility.

Subject to regulatory requirements, the Pipeline Companies attempt to recontract or remarket capacity at the maximum rates allowed under their tariffs, although at times the Pipeline Companies discount these rates to remain competitive. The Pipeline Companies' existing contracts mature at various times and in varying amounts of entitlement. The Pipeline Companies manage the recontracting process to mitigate the risk of a significant negative impact on operating revenue.

Historically, the Pipeline Companies have been able to provide competitively priced services because of access to a variety of relatively low cost supply basins, cost control measures and the relatively high level of firm entitlement that is sold on a seasonal and annual basis, which lowers the per unit cost of transportation. To date, the Pipeline Companies have avoided significant pipeline system bypasses.

Northern Natural Gas needs to compete aggressively to serve existing load and add new load. Northern Natural Gas has been successful in competing for a significant amount of the increased demand related to residential and commercial needs and the construction of new power plants and new fertilizer or other industrial plants. The growth related to utilities has historically been driven by population growth and increased commercial and industrial needs. Northern Natural Gas has been generally successful in negotiating increased transportation rates for customers who received discounted service when such contract terms are renegotiated and extended.

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

Northern Natural Gas' attractive competitive position relative to other pipelines in the upper Midwest was reinforced during the colder than normal winter of 2013-2014. Northern Natural Gas' customers' ability to access multiple supply basins has been critical to customers managing their reliability and supply costs. Northern Natural Gas' Field Area has access to diverse Mid-Continent, Permian and Rockies supplies with resulting prices delivered to Market Area customers at Demarcation significantly less than their alternative supply source.

Northern Natural Gas expects the current level of Field Area contracting to continue in the foreseeable future, as Market Area customers presently need to purchase competitively-priced supplies from the Field Area to support their existing and growth demand requirements. However, the revenue received from these Field Area contracts is expected to vary in relationship to the difference, or "spread," in natural gas prices between the MidContinent and Permian Regions and the price of the alternative supplies that are available to Northern Natural Gas' Market Area. This spread affects the value of the Field Area transportation capacity because natural gas from the MidContinent and Permian Regions that is transported through Northern Natural Gas' Field Area competes directly with natural gas delivered directly into the Market Area from Canada and other supply areas, including new shale gas producing areas outside of the Field Area.

Kern River's rates are based on a levelized rate design with recovery of 70% of the original investment during the initial long-term contracts ("Period One rates"). After expiration of the initial term, eligible customers elect to take service at rates ("Period Two rates") that are lower than Period One rates because they are designed to recover only the remaining plant balances. To the extent that eligible customers elected not to contract for service at Period Two rates, the volumes are turned back and sold at market rates for varying terms. Of the customers that were eligible to take Period Two service beginning October 1, 2016, 97% elected to extend their contracts at maximum Period Two rates, with 184,528 Dth per day electing 10-year contracts and 410,763 Dth per day electing 15-year contracts. Of the customers that were eligible to take Period Two service beginning May 1, 2017, 72% elected to extend their contracts at maximum Period Two rates, with 64,500 Dth per day electing 15-year contracts. As of December 1, 2016, Kern River has sold 318,362 Dth per day of the total turned back volume of 353,503 Dth per day with an average remaining contract term of three years. The remaining turned back capacity is sold on a short-term basis at market rates.

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

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

BHE TRANSMISSION

AltaLink

ALP, an indirect wholly owned subsidiary of BHE acquired on December 1, 2014, is a regulated electric transmission-only company headquartered in Alberta, Canada serving approximately 85% of Alberta's population. ALP connects generation plants to major load centers, cities and large industrial plants throughout its 87,000 square mile service territory, which covers a diverse geographic area including most major urban centers in central and southern Alberta. ALP's transmission facilities, consisting of approximately 8,200 miles of transmission lines and 300 substations as of December 31, 2016, are an integral part of the Alberta Integrated Electric System ("AIES").

The AIES is a network or grid of transmission facilities operating at high voltages ranging from 69kV to 500kV. The grid delivers electricity from generating units across Alberta, Canada through approximately 16,000 miles of transmission and over 600 substations. The AIES is interconnected to British Columbia's transmission system that links Alberta with the North American western interconnected system.

ALP is a transmission facility owner within the electricity industry in Alberta and is permitted to charge a tariff rate for the use of its transmission facilities. Such tariff rates are established on a cost-of-service basis, which are designed to allow ALP an opportunity to recover its costs of providing services and to earn a reasonable return on its investments. Transmission tariffs are approved by the AUC and are collected from the AESO.

The electricity industry in Alberta consists of four principal segments. Generators sell wholesale power into the power pool operated by the AESO and through direct contractual arrangements. Alberta's transmission system or grid is composed of high voltage power lines and related facilities that transmit electricity from generating facilities to distribution networks and directly connected end-users. Distribution facility owners are regulated by the AUC and are responsible for arranging for, or providing, regulated rate and regulated default supply services to convey electricity from transmission systems and distribution-connected generators to end-use customers. Retailers can procure energy through the power pool, through direct contractual arrangements with energy suppliers or ownership of generation facilities and arrange for its distribution to end-use customers.

In November 2015 the AESO finalized and made available the 2015 Long-Term Transmission Plan ("LTP"). The AESO mandate is defined in the Electric Utilities Act and its regulations, and requires the AESO to assess both current and future needs of Alberta's interconnected electrical system. The 2015 LTP is based on the AESO's forecast of load and generation as documented in the 2014 Long Term Outlook ("LTO"). The AESO 2015 LTP recognizes the province's economic outlook has changed significantly since then. Current economic conditions have resulted in slower provincial growth. In May 2016 the AESO finalized and made available the 2016 LTO. The 2016 LTO assumes Alberta's economy and corresponding load growth will recover within the next few years and takes into account the Alberta government's 2015 Climate Leadership Plan, which is in the process of being refined prior to becoming law.

BHE U.S. Transmission

BHE U.S. Transmission is engaged in various joint ventures to develop, own and operate transmission assets and is pursuing additional investment opportunities in the United States. Currently, BHE U.S. Transmission has two joint ventures with transmission assets that are operational.

BHE U.S. Transmission indirectly owns a 50% interest in ETT, along with subsidiaries of American Electric Power Company, Inc. ("AEP"). ETT owns and operates electric transmission assets in the ERCOT and, as of December 31, 2016, had total assets of $2.9 billion. ETT is regulated by the Public Utility Commission of Texas. A total of $2.7 billion of transmission projects were in-service as of December 31, 2016, with $0.3 billion of projects forecast to be completed in 2017 through 2020. ETT's transmission system includes approximately 1,200 miles of transmission lines and 30 substations as of December 31, 2016.

BHE U.S. Transmission also indirectly owns a 25% interest in Prairie Wind Transmission, LLC, a joint venture with AEP and Westar Energy, Inc., to build, own and operate a 108-mile, 345 kV transmission project in Kansas. The project cost $158 million and was fully placed in-service in November 2014.

BHE RENEWABLES

The subsidiaries comprising the BHE Renewables reportable segment own interests in several independent power projects that are in-service or under construction in the United States and in the Philippines. The following table presents certain information concerning these independent power projects as of December 31, 2016:

Generating Facility	Location	Energy Source	Installed	Power Purchase Agreement Expiration	Power Purchaser[1]	Facility Net Capacity (MW)[2]	Net Owned Capacity (MW)[2]
SOLAR:							
Topaz	California	Solar	2013-2014	2040	PG&E	550	550
Solar Star 1	California	Solar	2013-2015	2035	SCE	310	310
Solar Star 2	California	Solar	2013-2015	2035	SCE	276	276
Agua Caliente	Arizona	Solar	2012-2013	2039	PG&E	290	142
Community Solar Gardens	Minnesota	Solar	2016	2036	(5)	23	23
						1,449	1,301
WIND:							
Bishop Hill II	Illinois	Wind	2012	2032	Ameren	81	81
Pinyon Pines I	California	Wind	2012	2035	SCE	168	168
Pinyon Pines II	California	Wind	2012	2035	SCE	132	132
Jumbo Road	Texas	Wind	2015	2033	AE	300	300
Marshall	Kansas	Wind	2016	2036	MJMEC, KPP, KMEA & COIMO	72	72
Grand Prairie	Nebraska	Wind	2016	2036	OPPD	400	400
						1,153	1,153
GEOTHERMAL:							
Imperial Valley Projects	California	Geothermal	1982-2000	(3)	(3)	338	338
HYDROELECTRIC:							
Casecnan Project[4]	Philippines	Hydroelectric	2001	2021	NIA	150	128
Wailuku	Hawaii	Hydroelectric	1993	2023	HELCO	10	10
						160	138
NATURAL GAS:							
Saranac	New York	Natural Gas	1994	2017	TEMUS	245	196
Power Resources	Texas	Natural Gas	1988	2018	EDF	212	212
Yuma	Arizona	Natural Gas	1994	2024	SDG&E	50	50
Cordova	Illinois	Natural Gas	2001	2019	EGC	512	512
						1,019	970
Total Available Generating Capacity						4,119	3,900
PROJECTS UNDER CONSTRUCTION:							
Community Solar Gardens	Minnesota	Solar	2017	2037	(5)	72	72
						4,191	3,972

(1) TransAlta Energy Marketing U.S. ("TEMUS"); EDF Energy Services, LLC ("EDF"); San Diego Gas & Electric Company ("SDG&E"); Exelon Generation Company, LLC ("EGC"); Pacific Gas and Electric Company ("PG&E"), Ameren Illinois Company ("Ameren"), Southern California Edison ("SCE"), the Philippine National Irrigation Administration ("NIA"); Hawaii Electric Light Company, Inc. ("HELCO"); Austin Energy ("AE"); Omaha Public Power District ("OPPD"); U.S. General Services Administration ("USGSA"); Missouri Joint Municipal Electric Commission ("MJMEC"); Kansas Power Pool ("KPP"); Kansas Municipal Energy Agency ("KMEA"); and City of Independence, MO ("COIMO").

(2) Facility Net Capacity represents the lesser of nominal ratings or any limitations under applicable interconnection, power purchase, or other agreements for intermittent resources and the total net dependable capability available during summer conditions for all other units. An intermittent resource's nominal rating is the manufacturer's contractually specified capability (in MW) under specified conditions. Net Owned Capacity indicates BHE Renewables' ownership of Facility Net Capacity.

(3) The majority of the Imperial Valley Projects' Contract Capacity is currently sold to Southern California Edison Company under long-term power purchase agreements expiring in 2017 through 2026. Certain long-term power purchase agreement renewals have been entered into with other parties that begin upon the existing contracts' expiration and expire in 2039.

(4) Under the terms of the agreement with the NIA, CalEnergy Philippines will own and operate the Casecnan project for a 20-year cooperation period which ends December 11, 2021, after which ownership and operation of the project will be transferred to the NIA at no cost on an "as-is" basis. NIA also pays CalEnergy Philippines for delivery of water pursuant to the agreement.

(5) The power purchasers are commercial, industrial and not-for-profit organizations.

BHE Renewables' operating revenue is derived from the following business activities for the years ended December 31 (in millions):

	2016	2015	2014
Solar	$ 369	$ 383	$ 238
Wind	138	99	99
Geothermal	148	165	125
Hydro	30	23	107
Natural gas	58	58	54
Total operating revenue	$ 743	$ 728	$ 623

HOMESERVICES

HomeServices, a majority-owned subsidiary of BHE, is the second-largest residential real estate brokerage firm in the United States. In addition to providing traditional residential real estate brokerage services, HomeServices offers other integrated real estate services, including mortgage originations and mortgage banking; title and closing services; property and casualty insurance; home warranties; relocation services; and other home-related services. HomeServices' real estate brokerage business is subject to seasonal fluctuations because more home sale transactions tend to close during the second and third quarters of the year. As a result, HomeServices' operating results and profitability are typically higher in the second and third quarters relative to the remainder of the year. HomeServices' owned brokerages currently operate in nearly 540 offices in 28 states with over 29,000 agents under 38 brand names. The United States residential real estate brokerage business is subject to the general real estate market conditions, is highly competitive and consists of numerous local brokers and agents in each market seeking to represent sellers and buyers in residential real estate transactions. In October 2014, HomeServices acquired the remaining 50.1% of HomeServices Lending, a mortgage origination company.

In October 2012, HomeServices acquired a 66.7% interest in one of the largest residential real estate brokerage franchise networks in the United States, which offers and sells independently owned and operated residential real estate brokerage franchises. The noncontrolling interest member has the right to put the remaining 33.3% interest in the franchise business to HomeServices after March 2015 and HomeServices has the right to purchase the remaining 33.3% interest in the franchise business after March 2018 at an option exercise formula based on historical financial performance.

HomeServices' franchise network currently includes over 375 franchisees in over 1,500 brokerage offices in 47 states with over 46,000 agents under three brand names. In exchange for certain fees, HomeServices provides the right to use the Berkshire Hathaway HomeServices, Prudential or Real Living brand names and other related service marks, as well as providing orientation programs, training and consultation services, advertising programs and other services.

OTHER ENERGY BUSINESSES

Effective January 1, 2016, MidAmerican Energy Company transferred its nonregulated energy operations to MidAmerican Energy Services, LLC ("MES"), a subsidiary of BHE. MES is a nonregulated energy business consisting of competitive electricity and natural gas retail sales. MES' electric operations predominantly include sales to retail customers in Illinois, Texas, Ohio, Maryland and other states that allow customers to choose their energy supplier. MES' natural gas operations predominantly include sales to retail customers in Iowa and Illinois. Electricity and natural gas are purchased from producers and third party energy marketing companies and sold directly to commercial, industrial and governmental end-users. MES does not own electricity or natural gas production assets but hedges its contracted sales obligations either with physical supply arrangements or financial products. As of December 31, 2016, MES' contracts in place for the sale of electricity totaled 16,614,956 MWh with a weighted average life of 2.3 years and for the sale of natural gas totaled 33,642,454 Dth with a weighted average life of 1.4 years. In addition, MES manages natural gas supplies for a number of smaller commercial end-users, which includes the sale of natural gas to these customers to meet their supply requirements. Refer to Item 7A in this Form 10-K for a discussion of commodity price risk and derivative contracts.

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

	2016	2015	2014
Illinois	48%	51%	58%
Texas	13	15	17
Ohio	21	18	10
Maryland	7	7	8
Other	11	9	7
	100%	100%	100%

The percentages of natural gas sold to MES' customers by state for the years ended December 31 were as follows:

	2016	2015	2014
Iowa	86%	87%	87%
Illinois	9	8	8
Other	5	5	5
	100%	100%	100%

GENERAL REGULATION

BHE's regulated subsidiaries and certain affiliates are subject to comprehensive governmental regulation, which significantly influences their operating environment, prices charged to customers, capital structure, costs and, ultimately, their ability to recover costs and earn a reasonable return on invested capital. In addition to the discussion contained herein regarding general regulation, refer to "Regulatory Matters" in Item 1 of this Form 10-K for further discussion regarding certain regulatory matters.

Domestic Regulated Public Utility Subsidiaries

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

State Regulation

Historically, state regulatory commissions have established retail electric and natural gas rates on a cost-of-service basis, which are designed to allow a utility an opportunity to recover what each state regulatory commission deems to be the utility's reasonable costs of providing services, including a fair opportunity to earn a reasonable return on its investments based on its cost of debt and equity. In addition to return on investment, a utility's cost of service generally reflects a representative level of prudent expenses, including cost of sales, operating expense, depreciation and amortization, and income and other tax expense, reduced by wholesale electricity and other revenue. The allowed operating expenses are typically based on actual historical costs adjusted for known and measurable or forecasted changes. State regulatory commissions may adjust cost of service for various reasons, including pursuant to a review of: (a) the utility's revenue and expenses during a defined test period and (b) the utility's level of investment. State regulatory commissions typically have the authority to review and change rates on their own initiative; however, they may also initiate reviews at the request of a utility, utility customers or organizations representing groups of customers. In certain jurisdictions, the utility and such parties, however, may agree with one another not to request a review of or changes to rates for a specified period of time.

The retail electric rates of the Utilities are generally based on the cost of providing traditional bundled services, including generation, transmission and distribution services. The Utilities have established energy cost adjustment mechanisms and other cost recovery mechanisms in certain states, which help mitigate their exposure to changes in costs from those assumed in establishing base rates.

With certain limited exceptions, the Utilities have an exclusive right to serve retail customers within their service territories and, in turn, have an obligation to provide service to those customers. In some jurisdictions, certain classes of customers may choose to purchase all or a portion of their energy from alternative energy suppliers, and in some jurisdictions retail customers can generate all or a portion of their own energy. Under Oregon law, PacifiCorp has the exclusive right and obligation to provide electricity distribution services to all residential and nonresidential customers within its allocated service territory; however, nonresidential customers have the right to choose an alternative provider of energy supply. The impact of this right on PacifiCorp's consolidated financial results has not been material. In Washington, state law does not provide for exclusive service territory allocation. PacifiCorp's service territory in Washington is surrounded by other public utilities with whom PacifiCorp has from time to time entered into service area agreements under the jurisdiction of the WUTC. In Illinois, state law has established a competitive environment so that all Illinois customers are free to choose their retail service supplier. For customers that choose an alternative retail energy supplier, MidAmerican Energy continues to have an ongoing obligation to deliver the supplier's energy to the retail customer. MidAmerican Energy bills the retail customer for such delivery services. MidAmerican Energy also has an obligation to serve customers at regulated cost-based rates and has a continuing obligation to serve customers who have not selected a competitive electricity provider. The impact of this right on MidAmerican Energy's financial results has not been material. In Nevada, state law allows retail electric customers with an average annual load of one MW or more to file a letter of intent and application with the PUCN to acquire electric energy and ancillary services from another energy supplier. The law requires customers wishing to choose a new supplier to receive the approval of the PUCN to meet public interest standards. In particular, departing customers must secure new energy resources that are not under contract to the Nevada Utilities, the departure must not burden the Nevada Utilities with increased costs or cause any remaining customers to pay increased costs, and the departing customers must pay their portion of any deferred energy balances, all as determined by the PUCN. Also, the Utilities and the state regulatory commissions are individually evaluating how best to integrate private generation resources into their service and rate design, including considering such factors as maintaining high levels of customer safety and service reliability, minimizing adverse cost impacts and fairly allocating costs among all customers.

Also in Nevada, large natural gas customers using 12,000 therms per month with fuel switching capability are allowed by tariff to participate in the incentive natural gas rate tariff. Once a service agreement has been executed, a customer can compare natural gas prices under this tariff to alternative energy sources and choose its source of natural gas. In addition, natural gas customers using greater than 1,000 therms per day have the ability to secure their own natural gas supplies under the gas transportation tariff.

PacifiCorp

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

State Regulator	Base Rate Test Period	Adjustment Mechanism
UPSC	Forecasted or historical with known and measurable changes(1)	EBA under which 100% (beginning in June 2016) of the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates. Wheeling revenue is also included in the mechanism. Prior to June 2016, the amount deferred was 70% of the difference as noted above. Balancing account to provide for 100% recovery or refund of the difference between the level of REC revenues included in base rates and actual REC revenues after adjusting for a REC incentive authorized by the UPSC. Recovery mechanism for single capital investments that in total exceed 1% of existing rate base when a general rate case has occurred within the preceding 18 months.
OPUC	Forecasted	PCAM under which 90% of the difference between forecasted net variable power costs and production tax credits established under the annual TAM and actual net variable power costs and production tax credits is deferred and reflected in future rates. The difference between the forecasted and actual net variable power costs and production tax credits must fall outside of an established asymmetrical deadband range and is also subject to an earnings test. Annual TAM based on forecasted net variable power costs and production tax credits. Production tax credits were not included in forecasted net variable power costs prior to 2017. Renewable Adjustment Clause to recover the revenue requirement of new renewable resources and associated transmission costs that are not reflected in general rates. Balancing account for proceeds from the sale of RECs.
WPSC	Forecasted or historical with known and measurable changes(1)	ECAM under which 70% of the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates. Chemical costs and start-up fuel costs are also included in the mechanism starting in 2016. REC and sulfur dioxide revenue adjustment mechanism to provide for recovery or refund of 100% of any difference between actual REC and sulfur dioxide revenues and the level in rates.
WUTC	Historical with known and measurable changes	PCAM under which the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates after applying a \$4 million deadband for positive or negative net power cost variances. For net power cost variances between \$4 million and \$10 million, amounts to be recovered from customers are allocated 50/50 and amounts to be credited to customers are allocated 75/25 (customers/PacifiCorp). Positive or negative net power cost variances in excess of \$10 million are allocated 90/10 (customers/PacifiCorp). Deferral mechanism of costs for up to 24 months of new base load generation resources and eligible renewable resources and related transmission that qualify under the state's emissions performance standard and are not reflected in base rates. REC revenue tracking mechanism to provide credit of 100% of Washington-allocated REC revenues. Decoupling mechanism under which the difference between actual annual revenues and authorized revenues per customer is deferred and reflected in future rates, subject to an earnings test. To trigger a rate adjustment, the deferral balance must exceed plus or minus 2.5% of the authorized revenue at the end of each deferral period by rate class. Rate adjustments must not exceed a surcharge of 5% of the actual normalized revenue by class.
IPUC	Historical with known and measurable changes	ECAM under which 90% of the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates. Also provides for recovery or refund of 100% of the difference between the level of REC revenues included in base rates and actual REC revenues and differences in actual production tax credits compared to the amount in base rates.
CPUC	Forecasted	PTAM for major capital additions that allows for rate adjustments outside of the context of a traditional general rate case for the revenue requirement associated with capital additions exceeding \$50 million on a total-company basis. Filed as eligible capital additions are placed into service. ECAC that allows for an annual update to actual and forecasted net power costs. PTAM for attrition, a mechanism that allows for an annual adjustment to costs other than net power costs.

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

MidAmerican Energy

Under Iowa law, there are two options for temporary collection of higher rates following the filing of a request for a base rate increase. Collection can begin, subject to refund, either (1) within 10 days of filing, without IUB review, or (2) 90 days after filing, with approval by the IUB, depending upon the ratemaking principles and precedents utilized. In either case, if the IUB has not issued a final order within ten months after the filing date, the temporary rates become final and any difference between the requested rate increase and the temporary rates may then be collected subject to refund until receipt of a final order. Under Illinois law, new base rates may become effective 45 days after the filing of a request with the ICC, or earlier with ICC approval. The ICC has authority to suspend the proposed new rates, subject to hearing, for a period not to exceed approximately eleven months after filing. South Dakota law authorizes the SDPUC to suspend new base rates for up to six months during the pendency of rate proceedings; however, a utility may implement all or a portion of the proposed new rates six months after the filing of a request for a rate increase subject to refund pending a final order in the proceeding.

Iowa law also permits rate-regulated utilities to seek ratemaking principles with the IUB prior to the construction of certain types of new generating facilities. Pursuant to this law, MidAmerican Energy has applied for and obtained IUB ratemaking principles orders for a 484-MW (MidAmerican Energy's share) coal-fueled generating facility, a 495-MW combined cycle natural gas-fueled generating facility and 6,048 MW (nominal ratings) of wind-powered generating facilities, including 2,000 MW (nominal ratings) under construction, as of December 31, 2016. These ratemaking principles established cost caps for the projects and authorized a fixed rate of return on equity for the respective generating facilities over the regulatory life of the facilities in any future Iowa rate proceeding. As of December 31, 2016, the generating facilities in service totaled $5.6 billion, or 44%, of MidAmerican Energy's regulated property, plant and equipment, net, and were subject to these ratemaking principles at a weighted average return on equity of 11.8% with a weighted average remaining life of 31 years.

Under its current Iowa, Illinois and South Dakota electric tariffs, MidAmerican Energy is allowed to recover fluctuations in electric energy costs for its retail electric sales through fuel, or energy, cost adjustment mechanisms. The Iowa mechanism also includes production tax credits associated with wind-powered generation placed in service prior to 2013. Eligibility for production tax credits associated with MidAmerican Energy's earliest projects began expiring in 2014. Additionally, MidAmerican Energy has transmission adjustment clauses to recover certain transmission charges related to retail customers in all jurisdictions. The adjustment mechanisms reduce the regulatory lag for the recovery of energy and transmission costs related to retail electric customers in these jurisdictions.

Of the wind-powered generating facilities placed in service as of December 31, 2016, 1,763 MW (nominal ratings) have not been included in the determination of MidAmerican Energy’s Iowa retail electric base rates. In accordance with the related ratemaking principles, until such time as these generation assets are reflected in rates and ceasing thereafter, MidAmerican Energy reduced its revenue from Iowa energy adjustment clause recoveries by $5 million in 2015 and $9 million in 2016 and is to reduce its recoveries by $12 million for each calendar year thereafter.

MidAmerican Energy has mechanisms in Iowa where rate base may be reduced, including revenue sharing and retail customer benefits attributable to most of the wind-powered generating facilities placed in service in 2016 ("Wind X"). The revenue sharing mechanism originates from multiple ratemaking principles proceedings and reduces rate base for Iowa electric returns on equity exceeding an established benchmark. The Wind X customer benefit mechanism reduces rate base for the value of higher cost retail energy displaced by Wind X production.

MidAmerican Energy's cost of gas is collected for each jurisdiction in its gas rates through a uniform PGA, which is updated monthly to reflect changes in actual costs. Subject to prudence reviews, the PGA accomplishes a pass-through of MidAmerican Energy's cost of gas to its customers and, accordingly, has no direct effect on net income. MidAmerican Energy's DSM program costs are collected through separately established rates that are adjusted annually based on actual and expected costs, as approved by the respective state regulatory commission. As such, recovery of DSM program costs has no direct impact on net income.

NV Energy (Nevada Power and Sierra Pacific)

Rate Filings

Nevada statutes require the Nevada Utilities to file electric general rate cases at least once every three years with the PUCN. Sierra Pacific may also file natural gas general rate cases with the PUCN. The Nevada Utilities are also subject to a two-part fuel and purchased power adjustment mechanism. The Nevada Utilities make quarterly filings to reset BTER, based on the last 12 months of fuel and purchased power costs. The difference between actual fuel and purchased power costs and the revenue collected in the BTER is deferred into a balancing account. Nevada regulations allow an electric or natural gas utility that adjusts its BTER on a quarterly basis to request PUCN approval to make quarterly changes to its DEAA rate if the request is in the public interest. The Nevada Utilities received approval from the PUCN and file quarterly adjustments to the DEAA rate to clear amounts deferred into the balancing account. During required annual DEAA proceedings, the prudence of fuel and purchased power costs is reviewed, and if any costs are disallowed on such grounds, the disallowances will be incorporated into the next quarterly BTER rate change. Also, on an annual basis, the Nevada Utilities (a) seek a determination that energy efficiency program expenditures were reasonable, (b) request that the PUCN reset base and amortization energy efficiency program rates, and (c) request that the PUCN reset base and amortization energy efficiency implementation rates. When the Nevada Utilities' earned rate of return for a calendar year exceeds the rate of return used to set base tariff general rates, they are obligated to refund energy efficiency implementation revenue previously collected for that year.

Energy Choice Initiative

In November 2016, a majority of Nevada voters supported a ballot measure to amend Article 1 of the Nevada Constitution. If approved again in 2018, the proposed constitutional amendment would require the Nevada Legislature to create, on or before July 2023, an open and competitive retail electric market that includes provisions to reduce costs to customers, protect against service disconnections and unfair practices, and prohibit the granting of monopolies and exclusive franchises for the generation of electricity. The outcome of any customer choice initiative could have broad implications to the Nevada Utilities. The Governor issued an executive order establishing the Governor’s Committee on Energy Choice in which the Nevada Utilities will have representation. The Nevada Utilities will be engaged in the legislative process but cannot assess or predict the outcome of the potential constitutional amendment or the financial impact, if any, at this time. The uncertainty created by the ballot initiative complicates both the short-term allocation of resources and long-term resource planning for the Nevada Utilities, including the ability to forecast load growth and the timing of resource additions. This uncertainty in planning is evidenced by a recent decision the PUCN issued denying Nevada Power’s proposed purchase of the South Point Energy Center, citing the unknown outcomes of the energy choice initiative as one of the factors considered in their decision.

Federal Regulation

The FERC is an independent agency with broad authority to implement provisions of the Federal Power Act, the Natural Gas Act ("NGA"), the Energy Policy Act of 2005 ("Energy Policy Act") and other federal statutes. The FERC regulates rates for wholesale sales of electricity; transmission of electricity, including pricing and regional planning for the expansion of transmission systems; electric system reliability; utility holding companies; accounting and records retention; securities issuances; construction and operation of hydroelectric facilities; and other matters. The FERC also has the enforcement authority to assess civil penalties of up to $1.2 million per day per violation of rules, regulations and orders issued under the Federal Power Act. The Utilities have implemented programs and procedures that facilitate and monitor compliance with the FERC's regulations described below. MidAmerican Energy is also subject to regulation by the NRC pursuant to the Atomic Energy Act of 1954, as amended ("Atomic Energy Act"), with respect to its ownership interest in the Quad Cities Station.

Wholesale Electricity and Capacity

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

The Utilities' and BHE Renewables' authority to sell electricity in wholesale electricity markets at market-based rates is subject to triennial reviews conducted by the FERC. Accordingly, the Utilities and BHE Renewables are required to submit triennial filings to the FERC that demonstrate a lack of market power over sales of wholesale electricity and electric generation capacity in their respective market areas. In June 2016, BHE Renewables submitted a triennial filing to the FERC for the southwest region and PacifiCorp and NV Energy submitted a triennial filing for the northwest region. These filings are pending at the FERC. MidAmerican Energy currently has no triennial reviews pending with the FERC. Under the FERC's market-based rules, the Utilities must also file with the FERC a notice of change in status when there is a change in the conditions that the FERC relied upon in granting market-based rate authority.

On December 9, 2014, the FERC issued an order requesting that the BHE subsidiaries having authority to sell power and energy at market-based rates, including the Utilities, show cause why their market-based rate authority remains just and reasonable following BHE's acquisition of NV Energy. In June 2016, the FERC issued an order for all BHE subsidiaries, including the Utilities, with market-based rates to amend their respective market-based rate tariffs to preclude them from selling at market-based rates in the PacifiCorp East, PacifiCorp West, Idaho Power Company and NorthWestern Corporation balancing authority areas (the "Mitigated BAAs"). These tariff amendments were filed. Sales may be made in the Mitigated BAAs at cost-based rates. In addition, the specified BHE subsidiaries were ordered to issue refunds for market-based wholesale electricity sales in the Mitigated BAAs for the period from January 2015 through April 2016, to the extent such sales were priced above cost-based rates. Such refunds, totaling less than $1 million, were made by PacifiCorp, Nevada Power and Sierra Pacific in July 2016. MidAmerican Energy and BHE Renewables do not transact in the Mitigated BAAs. In July 2016, the specified BHE subsidiaries affected in the order filed with the FERC a request for rehearing and clarification. In December 2016, the FERC denied the request for rehearing, made limited clarifications to the June 2016 order and accepted the conforming tariffs filed by the BHE subsidiaries. The specified BHE subsidiaries affected in the order do not believe the order will have a material impact on their respective consolidated financial statements.

Transmission

PacifiCorp's and the Nevada Utilities' wholesale transmission services are regulated by the FERC under cost-based regulation subject to PacifiCorp's and the Nevada Utilities' OATT, respectively. These services are offered on a non-discriminatory basis, which means that all potential customers are provided an equal opportunity to access the transmission system. PacifiCorp's and the Nevada Utilities' transmission business is managed and operated independently from its wholesale marketing business in accordance with the FERC's Standards of Conduct. PacifiCorp and the Nevada Utilities have made several required compliance filings in accordance with these rules.

In December 2011, PacifiCorp adopted a cost-based formula rate under its OATT for its transmission services. Cost-based formula rates are intended to be an effective means of recovering PacifiCorp's investments and associated costs of its transmission system without the need to file rate cases with the FERC, although the formula rate results are subject to discovery and challenges by the FERC and intervenors. A significant portion of these services are provided to PacifiCorp's energy supply management function.

MidAmerican Energy participates in the MISO as a transmission-owning member. Accordingly, the MISO is the transmission provider under its FERC-approved OATT. While the MISO is responsible for directing the operation of MidAmerican Energy's transmission system, MidAmerican Energy retains ownership of its transmission assets and, therefore, is subject to the FERC's reliability standards discussed below. MidAmerican Energy's transmission business is managed and operated independently from its wholesale marketing business in accordance with the FERC Standards of Conduct.

MidAmerican Energy has approval from the MISO to construct and own four Multi-Value Projects ("MVPs") located in Iowa and Illinois that will add approximately 245 miles of 345 kV transmission line to MidAmerican Energy's transmission system, of which 191 miles have been placed in service as of December 31, 2016. The MISO OATT allows for broad cost allocation for MidAmerican Energy's MVPs, including similar MVPs of other MISO participants. Accordingly, a significant portion of the revenue requirement associated with MidAmerican Energy's MVP investments will be shared with other MISO participants based on the MISO's cost allocation methodology, and a portion of the revenue requirement of the other participants' MVPs will be allocated to MidAmerican Energy. Additionally, MidAmerican Energy has approval from the FERC to include 100% of construction work in progress in the determination of rates for its MVPs and to use a forward-looking rate structure for all of its transmission investments and costs. The transmission assets and financial results of MidAmerican Energy's MVPs are excluded from the determination of its retail electric rates.

The FERC has established an extensive number of mandatory reliability standards developed by the NERC and the WECC, including planning and operations, critical infrastructure protection and regional standards. Compliance, enforcement and monitoring oversight of these standards is carried out by the FERC; the NERC; and the WECC for PacifiCorp, Nevada Power, and Sierra Pacific; and the Midwest Reliability Organization for MidAmerican Energy.

Hydroelectric

The FERC licenses and regulates the operation of hydroelectric systems, including license compliance and dam safety programs. Most of PacifiCorp's hydroelectric generating facilities are licensed by the FERC as major systems under the Federal Power Act, and certain of these systems are licensed under the Oregon Hydroelectric Act. Under the Federal Power Act, 16 dams associated with PacifiCorp's hydroelectric generating facilities licensed with the FERC are classified as "high hazard potential," meaning it is probable in the event of dam failure that loss of human life in the downstream population could occur. The FERC provides guidelines utilized by PacifiCorp in development of public safety programs consisting of a dam safety program and emergency action plans.

PacifiCorp's Klamath River hydroelectric system is the only significant hydroelectric system for which PacifiCorp has a pending relicensing process with the FERC. Refer to Note 16 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 13 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K for an update regarding hydroelectric relicensing for PacifiCorp's Klamath River hydroelectric system.

Nuclear Regulatory Commission

General

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

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

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

The NRC also regulates the decommissioning of nuclear powered generating facilities, including the planning and funding for the eventual decommissioning of the facilities. In accordance with these regulations, MidAmerican Energy submits a biennial report to the NRC providing reasonable assurance that funds will be available to pay its share of the costs of decommissioning Quad Cities Station. MidAmerican Energy has established a trust for the investment of funds collected for nuclear decommissioning of Quad Cities Station.

Under the Nuclear Waste Policy Act of 1982 ("NWPA"), the U.S. Department of Energy ("DOE") is responsible for the selection and development of repositories for, and the permanent disposal of, spent nuclear fuel and high-level radioactive wastes. Exelon Generation, as required by the NWPA, signed a contract with the DOE under which the DOE was to receive spent nuclear fuel and high-level radioactive waste for disposal beginning not later than January 1998. The DOE did not begin receiving spent nuclear fuel on the scheduled date and remains unable to receive such fuel and waste. The costs to be incurred by the DOE for disposal activities were previously being financed by fees charged to owners and generators of the waste. In accordance with a 2013 ruling by the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit"), the DOE, in May 2014, provided notice that, effective May 16, 2014, the spent nuclear fuel disposal fee would be zero. In 2004, Exelon Generation, reached a settlement with the DOE concerning the DOE's failure to begin accepting spent nuclear fuel in 1998. As a result, Quad Cities Station has been billing the DOE, and the DOE is obligated to reimburse the station for all station costs incurred due to the DOE's delay. Exelon Generation has completed construction of an interim spent fuel storage installation ("ISFSI") at Quad Cities Station to store spent nuclear fuel in dry casks in order to free space in the storage pool. The first pad at the ISFSI is expected to facilitate storage of casks to support operations at Quad Cities Station until at least 2020. The first storage in a dry cask commenced in November 2005. By 2020, Exelon Generation plans to add a second pad to the ISFSI to accommodate storage of spent nuclear fuel through the end of operations at Quad Cities Station.

Nuclear Insurance

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

Exelon Generation purchases private market nuclear liability insurance for Quad Cities Station in the maximum available amount of $375 million, which includes coverage for MidAmerican Energy's ownership. In accordance with Price-Anderson, excess liability protection above that amount is provided by a mandatory industry-wide Secondary Financial Protection program under which the licensees of nuclear generating facilities could be assessed for liability incurred due to a serious nuclear incident at any commercial nuclear reactor in the United States. Currently, MidAmerican Energy's aggregate maximum potential share of an assessment for Quad Cities Station is approximately $64 million per incident, payable in installments not to exceed $10 million annually.

The property insurance covers property damage, stabilization and decontamination of the facility, disposal of the decontaminated material and premature decommissioning arising out of a covered loss. For Quad Cities Station, Exelon Generation purchases primary and excess property insurance protection for the combined interests in Quad Cities Station, with coverage limits totaling $2.1 billion. MidAmerican Energy also directly purchases extra expense coverage for its share of replacement power and other extra expenses in the event of a covered accidental outage at Quad Cities Station. The property and related coverages purchased directly by MidAmerican Energy and by Exelon Generation, which includes the interests of MidAmerican Energy, are underwritten by an industry mutual insurance company and contain provisions for retrospective premium assessments to be called upon based on the industry mutual board of directors' discretion for adverse loss experience. Currently, the maximum retrospective amounts that could be assessed against MidAmerican Energy from industry mutual policies for its obligations associated with Quad Cities Station total $9 million.

The master nuclear worker liability coverage, which is purchased by Exelon Generation for Quad Cities Station, is an industry-wide guaranteed-cost policy with an aggregate limit of $375 million for the nuclear industry as a whole, which is in effect to cover tort claims of workers in nuclear-related industries.

United States Mine Safety

PacifiCorp's mining operations are regulated by the Federal Mine Safety and Health Administration, which administers federal mine safety and health laws and regulations, and state regulatory agencies. The Federal Mine Safety and Health Administration has the statutory authority to institute a civil action for relief, including a temporary or permanent injunction, restraining order or other appropriate order against a mine operator who fails to pay penalties or fines for violations of federal mine safety standards. Federal law requires PacifiCorp to have a written emergency response plan specific to each underground mine it operates, which is reviewed by the Federal Mine Safety and Health Administration every six months, and to have at least two mine rescue teams located within one hour of each mine. Information regarding PacifiCorp's mine safety violations and other legal matters disclosed in accordance with Section 1503(a) of the Dodd-Frank Reform Act is included in Exhibit 95 to this Form 10-K.

Interstate Natural Gas Pipeline Subsidiaries

The Pipeline Companies are regulated by the FERC, pursuant to the NGA and the Natural Gas Policy Act of 1978. Under this authority, the FERC regulates, among other items, rates; charges; terms and conditions of service; and the construction and operation of interstate pipelines, storage and related facilities, including the extension, expansion or abandonment of such facilities. The Pipeline Companies hold certificates of public convenience and necessity issued by the FERC, which authorize them to construct, operate and maintain their pipeline and related facilities and services.

FERC regulations and the Pipeline Companies' tariffs allow each of the Pipeline Companies to charge approved rates for the services set forth in their respective tariff. Generally, these rates are a function of the cost of providing services to their customers, including prudently incurred operations and maintenance expenses, taxes, depreciation and amortization and a reasonable return on their investments. Both Northern Natural Gas' and Kern River's tariff rates have been developed under a rate design methodology whereby substantially all of their fixed costs, including a return on invested capital and income taxes, are collected through reservation charges, which are paid by firm transportation and storage customers regardless of volumes shipped. Commodity charges, which are paid only with respect to volumes actually shipped, are designed to recover the remaining, primarily variable, costs. Kern River's reservation rates have historically been approved using a "levelized" cost-of-service methodology so that the rate remains constant over the levelization period. This levelized cost of service has been achieved by using a FERC-approved depreciation schedule in which depreciation increases as interest expense and return on equity amounts decrease. Both Northern Natural Gas' and Kern River's rates are subject to change in future general rate proceedings.

Natural gas transportation companies may not grant any undue preference to any customer. FERC regulations also restrict each pipeline's marketing affiliates' access to certain non-public information regarding their affiliated interstate natural gas transmission pipelines.

Interstate natural gas pipelines are also subject to regulations administered by the Office of Pipeline Safety within the Pipeline and Hazardous Materials Safety Administration, an agency within the United States Department of Transportation ("DOT"). Federal pipeline safety regulations are issued pursuant to the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA"), which establishes safety requirements in the design, construction, operation and maintenance of interstate natural gas facilities, and requires an entity that owns or operates pipeline facilities to comply with such plans. Major amendments to the NGPSA include the Pipeline Safety Improvement Act of 2002 ("2002 Act"), the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 ("2006 Act") and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Act").

The 2002 Act established additional safety and pipeline integrity regulations for all natural gas pipelines in high-consequence areas. The 2002 Act imposed major new requirements in the areas of operator qualifications, risk analysis and integrity management. The 2002 Act mandated more frequent periodic inspection or testing of natural gas pipelines in high-consequence areas, which are locations where the potential consequences of a natural gas pipeline accident may be significant or may do considerable harm to persons or property. Pursuant to the 2002 Act, the DOT promulgated new regulations that require natural gas pipeline operators to develop comprehensive integrity management programs, to identify applicable threats to natural gas pipeline segments that could impact high-consequence areas, to assess these segments, and to provide ongoing mitigation and monitoring. The regulations required that all baseline high-consequence area segments be assessed by December 17, 2012 and require recurring inspections every seven years thereafter. Based on the Pipeline Companies' extensive compliance efforts, they have completed all required high-consequence area pipeline baseline integrity assessments. Kern River also completed the required in-line inspections in early 2011 on that portion of its pipeline system required by the conditions associated with a special permit which allowed for an increase to the maximum allowable operating pressure.

The 2006 Act required pipeline operators to institute human factors management plans for personnel employed in pipeline control centers. DOT regulations published pursuant to the 2006 Act required development and implementation of written control room management procedures.

The 2011 Act was a response to natural gas pipeline incidents, most notably the San Bruno natural gas pipeline explosion that occurred in September 2010 in California. The 2011 Act increased the maximum allowable civil penalties for violations, directs operator assistance for Federal authorities conducting investigations and authorized the DOT to hire additional inspection and enforcement personnel. The 2011 Act also directed the DOT to study several topics, including the definition of high-consequence areas, the use of automatic shutoff valves in high-consequence areas, expansion of integrity management requirements beyond high-consequence areas, and cast iron pipe replacement. The studies are complete, and a number of notices of proposed rulemaking have been issued. The BHE Pipeline Group anticipates final rules on a number of areas sometime in 2017. The BHE Pipeline Group cannot currently assess the potential cost of compliance with new rules and regulations under the 2011 Act.

The DOT and related state agencies routinely audit and inspect the pipeline facilities for compliance with their regulations. The Pipeline Companies conduct internal audits of their facilities every four years; with more frequent reviews of those deemed higher risk. The Pipeline Companies also conduct preliminary audits in advance of agency audits. Compliance issues that arise during these audits or during the normal course of business are addressed on a timely basis. The Pipeline Companies believe their pipeline systems comply in all material respects with the NGPSA and with DOT regulations issued pursuant to the NGPSA.

Northern Powergrid Distribution Companies

The Northern Powergrid Distribution Companies, as holders of electricity distribution licenses, are subject to regulation by GEMA. GEMA regulates distribution network operators ("DNOs") within the terms of the Electricity Act 1989 and the terms of DNO licenses, which are revocable with 25 years notice. Under the Electricity Act 1989, GEMA has a duty to ensure that DNOs can finance their regulated activities and DNOs have a duty to maintain an investment grade credit rating. GEMA discharges certain of its duties through its staff within Ofgem. Each of fourteen licensed DNOs distributes electricity from the national grid transmission system to end users within its respective distribution services area.

DNOs are subject to price controls, enforced by Ofgem, that limit the revenue that may be recovered and retained from their electricity distribution activities. The regulatory regime that has been applied to electricity distributors in Great Britain encourages companies to look for efficiency gains in order to improve profits. The distribution price control formula also adjusts the revenue received by DNOs to reflect a number of factors, including, but not limited to, the rate of inflation (as measured by the United Kingdom's Retail Prices Index) and the quality of service delivered by the licensee's distribution system. The current price control, Electricity Distribution 1 ("ED1"), has been set for a period of eight years, starting April 1, 2015, although the formula has been, and may be, reviewed by the regulator following public consultation. The procedure and methodology adopted at a price control review are at the reasonable discretion of Ofgem. Ofgem's judgment of the future allowed revenue of licensees is likely to take into account, among other things:

- the actual operating and capital costs of each of the licensees;
- the operating and capital costs that each of the licensees would incur if it were as efficient as, in Ofgem's judgment, the more efficient licensees;
- the actual value of certain costs which are judged to be beyond the control of the licensees;
- the taxes that each licensee is expected to pay;
- the regulatory value ascribed to the expenditures that have been incurred in the past and the efficient expenditures that are to be incurred in the forthcoming regulatory period;
- the rate of return to be allowed on expenditures that make up the regulatory asset value;
- the financial ratios of each of the licensees and the license requirement for each licensee to maintain investment grade status;
- an allowance in respect of the repair of the pension deficits in the defined benefit pension schemes sponsored by each of the licensees; and
- any under- or over-recoveries of revenues, relative to allowed revenues, in the previous price control period.

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

A new price control can be implemented by GEMA without the consent of the DNO, but if a licensee disagrees with a change to its license it can appeal the matter to the United Kingdom's Competition and Markets Authority ("CMA"), as can certain other parties. Any appeals must be notified within 20 working days of the license modification by GEMA. If the CMA determines that the appellant has relevant standing, then the statute requires that the CMA complete its process within six months, or in some exceptional circumstances seven months. The Northern Powergrid Distribution Companies appealed Ofgem's proposals for the resetting of the formula that commenced April 1, 2015, as did one other party, and the CMA subsequently revised GEMA's decision.

The current electricity distribution price control became effective April 1, 2015 and is due to terminate on March 31, 2023, and will be immediately replaced with a new price control (in line with GEMA's current timetable). This price control is the first to be set for electricity distribution in Great Britain since Ofgem completed its review of network regulation (known as the RPI-X @ 20 project). The key changes to the price control calculations, compared to those used in previous price controls are that:

- the period over which new regulatory assets are depreciated is being gradually lengthened, from 20 years to 45 years, with the change being phased over eight years;
- allowed revenues will be adjusted during the price control period, rather than at the next price control review, to partially reflect cost variances relative to cost allowances;
- the allowed cost of debt will be updated within the price control period by reference to a long-run trailing average based on external benchmarks of utility debt costs;
- allowed revenues will be adjusted in relation to some new service standard incentives, principally relating to speed and service standards for new connections to the network; and
- there is scope for a mid-period review and adjustment to revenues in the latter half of the period for any changes in the outputs required of licensees for certain specified reasons.

Under the price control, as revised by the CMA, and excluding the effects of incentive schemes and any deferred revenues from the prior price control, the base allowed revenue of Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc decreased by approximately 1.0% and 0.5%, respectively, from 2015-16 to 2016-17, and then remains constant in all subsequent years within the price control period (RIIO-ED1) through 2022-23, before the addition of inflation. Nominal base allowed revenues will increase in line with inflation.

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

ALP Transmission

ALP is regulated by the AUC, pursuant to the Electric Utilities Act (Alberta), the Public Utilities Act (Alberta), the Alberta Utilities Commission Act (Alberta) and the Hydro and Electric Energy Act (Alberta). The AUC is an independent, quasi-judicial agency established by the province of Alberta, Canada, which is responsible for, among other things, approving the tariffs of transmission facility owners, including ALP, and distribution utilities, acquisitions of such transmission facility owners or utilities, and construction and operation of new transmission projects in Alberta. The AUC also investigates and rules on regulated rate disputes and system access problems. The AUC regulates and oversees Alberta's electricity transmission sector with broad authority that may impact many of ALP's activities, including its tariffs, rates, construction, operations and financing.

The AUC has various core functions in regulating the Alberta electricity transmission sector, including the following:

- regulating and adjudicating issues related to the operation of electric utilities within Alberta;
- processing and approving general tariff applications relating to revenue requirements and rates of return including deemed capital structure for regulated utilities while ensuring that utility rates are just and reasonable and approval of the transmission tariff rates of regulated transmission providers paid by the AESO, which is the independent transmission system operator in Alberta, Canada that controls the operation of ALP's transmission system;
- approving the need for new electricity transmission facilities and permits to build and licenses to operate electricity transmission facilities;
- reviewing operations and accounts from electric utilities and conducting on-site inspections to ensure compliance with industry regulation and standards;
- adjudicating enforcement issues including the imposition of administrative penalties that arise when market participants violate the rules of the AESO; and
- collecting, storing, analyzing, appraising and disseminating information to effectively fulfill its duties as an industry regulator.

ALP's tariffs are regulated by the AUC under the provisions of the Electric Utilities Act in respect of rates and terms and conditions of service. The Electric Utilities Act and related regulations require the AUC to consider that it is in the public interest to provide consumers the benefit of unconstrained transmission access to competitive generation and the wholesale electricity market. In regulating transmission tariffs, the AUC must facilitate sufficient investment to ensure the timely upgrade, enhancement or expansion of transmission facilities, and foster a stable investment climate and a continued stream of capital investment for the transmission system.

Under the Electric Utilities Act, ALP prepares and files applications with the AUC for approval of tariffs to be paid by the AESO for the use of its transmission facilities, and the terms and conditions governing the use of those facilities. The AUC reviews and approves such tariff applications based on a cost-of-service regulatory model under a forward test year basis. Under this model, the AUC provides ALP with a reasonable opportunity to (i) earn a fair return on equity; and (ii) recover its forecast costs, including operating expenses, depreciation, borrowing costs and taxes associated with its regulated transmission business. The AUC must approve tariffs that are just, reasonable, and not unduly preferential, arbitrary or unjustly discriminatory. ALP's transmission tariffs are not dependent on the price or volume of electricity transported through its transmission system.

The AESO is an independent system operator in Alberta, Canada that oversees the AIES and wholesale electricity market. The AESO is responsible for directing the safe, reliable and economic operation of the AIES, including long-term transmission system planning. ALP and the other transmission facility owners receive substantially all of their transmission tariff revenues from the AESO. The AESO, in turn, charges wholesale tariffs, approved by the AUC, in a manner that promotes fair and open access to the AIES and facilitates a competitive market for the purchase and sale of electricity. The AESO monitors compliance with approved reliability standards, which are enforced by the Market Surveillance Administrator, which may impose penalties on transmission facility owners for non-compliance with the approved reliability standards.

The AESO determines the need and plans for the expansion and enhancement of a congestion free transmission system in Alberta in accordance with applicable law and reliability standards. The AESO's responsibilities include long-term transmission planning and management, including assessing and planning for the current and future transmission system capacity needs of AESO market participants. When AESO determines an expansion or enhancement of the transmission system is needed, with limited exceptions, it submits an application to the AUC for approval of the proposed expansion or enhancement. The AESO then determines which transmission provider should submit an application to the AUC for a permit and license to construct and operate the designated transmission facilities. Generally the transmission provider operating in the geographic area where the transmission facilities expansion or enhancement is to be located is selected by the AESO to build, own and operate the transmission facilities. In addition, Alberta law provides that certain transmission projects may be subject to a competitive process open to qualified bidders.

Independent Power Projects

The Yuma, Cordova, Saranac, Power Resources, Topaz, Agua Caliente, Solar Star, Bishop Hill II, Jumbo Road, Marshall, Grande Prairie and Pinyon Pines independent power projects are Exempt Wholesale Generators ("EWG") under the Energy Policy Act while the Imperial Valley and Wailuku independent power projects are currently certified as Qualifying Facilities ("QF") under the Public Utility Regulatory Policies Act of 1978. Both EWGs and QFs are generally exempt from compliance with extensive federal and state regulations that control the financial structure of an electric generating plant and the prices and terms at which electricity may be sold by the facilities. In addition, the Cordova, Saranac, Yuma, Imperial Valley, Topaz, Agua Caliente, Solar Star, Bishop Hill II, Marshall, Grande Prairie and Pinyon Pines independent power projects have obtained authority from the FERC to sell their power using market-based rates. Jumbo Road's entire output is dedicated to its offtaker within the Electric Reliability Council of Texas ("ERCOT") and does not require market-based authority for such sales solely within ERCOT as the ERCOT market is not a FERC-jurisdictional market. Similarly, Wailuku sells its output solely to the Hawaii Electric Company within the Hawaii electric grid which is not a FERC-jurisdictional market and Wailuku therefore does not require market-based rate authority.

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

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

Residential Real Estate Brokerage Company

HomeServices is regulated by the United States Bureau of Consumer Financial Protection under the Truth In Lending Act ("TILA") and the Real Estate Settlement Procedures Act ("RESPA"); the United States Federal Trade Commission with respect to certain franchising activities; and by state agencies where it operates. TILA primarily governs the real estate lending process by mandating lenders to fully inform borrowers about loan costs. RESPA primarily governs the real estate settlement process by mandating all parties fully inform borrowers about all closing costs, lender servicing and escrow account practices, and business relationships between closing service providers and other parties to the transaction.

REGULATORY MATTERS

In addition to the discussion contained herein regarding regulatory matters, refer to "General Regulation" in Item 1 of this Form 10-K for further discussion regarding the general regulatory framework.

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 2015, PacifiCorp received approval from the commissions.

In December 2014, PacifiCorp also filed an advice letter with the CPUC to request approval to sell certain Utah mining assets and to establish memorandum accounts to track the costs associated with the Utah Mine Disposition for future recovery. In July 2015, the CPUC Energy Division issued a letter requiring PacifiCorp to file a formal application for approval of the sale of certain Utah mining assets. Accordingly, in September 2015, PacifiCorp filed an application with the CPUC. On February 6, 2017, a joint motion was filed with the CPUC seeking approval of a settlement agreement reached by PacifiCorp and all other parties. The agreement states, among other things, that the decision to sell certain Utah mining assets is in the public interest. Parties also reserve their rights to additional testimony, briefs, and hearings to the extent the CPUC determines that additional California Environmental Quality Act proceedings are necessary. A CPUC decision on the joint motion and settlement agreement is expected in 2017.

For additional information related to the accounting impacts associated with the Utah Mine Disposition, refer to Notes 5 and 9 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K.

Utah

In March 2016, PacifiCorp filed its annual EBA with the UPSC requesting recovery of $19 million in deferred net power costs for the period January 1, 2015 through December 31, 2015. A settlement was reached with all parties and the UPSC approved the settlement in October 2016, authorizing recovery of $15 million of deferred net power costs. New rates were effective November 2016.

In March 2016, PacifiCorp filed its annual REC balancing account application with the UPSC requesting recovery of $7 million for the period January 1, 2015 through December 31, 2015. The UPSC approved rates requested in the application on an interim basis effective June 2016, and final rates August 2016.

The Utah Sustainable Transportation and Energy Plan was signed into law in March 2016. The legislation establishes a five-year pilot program to provide up to $10 million annually of mandated funding for electric vehicle infrastructure and clean coal research, and authorizes funding at the commission's discretion for solar development, utility-scale battery storage, and other innovative technology, economic development and air quality initiatives. The legislation allows PacifiCorp to change its regulatory accounting for energy efficiency services and programs from expense to capital, to be amortized over a ten-year period. The difference between amounts collected in rates for energy efficiency services and programs and the annual amount of cost amortization will result in a regulatory liability that may be used for depreciation of its coal-fired plants, as determined by the commission. Beginning June 1, 2016, the legislation mandates full recovery of Utah's share of incremental fuel, purchased power and other variable supply costs through the EBA that are not fully in base rates rather than the prior recovery of 70%. The legislation also allows for the approval by the UPSC of a renewable energy tariff that would allow qualifying customers to receive 100% renewable energy from PacifiCorp. A renewable energy tariff was filed with the UPSC in June 2016, which the UPSC approved in August 2016. In September 2016, PacifiCorp filed an application seeking approval of phase 1 of its proposed five-year pilot program with an annual budget of $10 million. The UPSC issued an order approving phase I of the five-year pilot program in December 2016.

In November 2016, PacifiCorp filed cost of service analyses, as ordered by the UPSC, to quantify the cost shifting due to net metering. The UPSC ordered the analyses to comply with a 2014 law requiring the examination of whether the costs of net metering exceed the benefits to PacifiCorp and other customers. The filing includes a proposal for a new rate schedule for residential customer generators with a three-part rate based on the cost of serving this class of customer, which will mitigate future cost shifting. PacifiCorp proposed that the new rate schedule only apply to new net metering customers that submit applications after December 9, 2016. On December 9, 2016, PacifiCorp requested that the effective date for the start of a transitional tariff be suspended while it works with stakeholders on a collaborative process to resolve net metering rate design issues. The filing also requests an increase in the application fees for net metering. The UPSC has set a procedural schedule with hearings to occur in August 2017.

Oregon

In April 2016, PacifiCorp submitted its initial filing for the annual TAM filing in Oregon requesting an annual increase of $20 million, or an average price increase of 2%, based on forecasted net power costs and loads for calendar year 2017. In accordance with the passage of Oregon Senate Bill No. 1547-B, the filing included the impact of expiring production tax credits, which account for $5 million of the requested increase. In October 2016, the OPUC issued a preliminary order approving PacifiCorp's request. PacifiCorp submitted the final update in November 2016, which reflected a rate increase of $12 million, or an average price increase of 1%, effective January 2017. In December 2016, the OPUC issued its final order.

Wyoming

In March 2016, PacifiCorp filed its annual ECAM and REC and RRA applications with the WPSC. The ECAM filing requested approval to recover $12 million in deferred net power costs for the period January 1, 2015 through December 31, 2015, and the RRA application requests approval to refund $1 million to customers. In May 2016, the WPSC approved ECAM and RRA rates on an interim basis. In October 2016, the WPSC approved an all-party settlement allowing recovery of $11 million in deferred net power costs and to allow interim rates for the RRA that were effective in May 2016 to become final. A net decrease in rates for the ECAM became effective in November 2016.

Washington

In December 2013, the WUTC approved an annual increase of $17 million, or an average price increase of 6%, effective December 2013 related to a general rate case filed in January 2013 requesting $37 million, or an average price increase of 12%. In January 2014, PacifiCorp filed a petition for judicial review of certain findings of the WUTC's December 2013 order. In April 2016, the Washington Court of Appeals issued its order in the appeal of the general rate case. The two issues before the court were the WUTC's decisions to: (1) re-price power purchase agreements with California and Oregon qualifying facilities at market prices; and (2) the cost of capital, including use of a hypothetical capital structure. The court affirmed the WUTC, deferring to the WUTC's discretion in ratemaking and concluding that it did not abuse that discretion.

In September 2016, the WUTC issued final orders in PacifiCorp's November 2015 rate filing, two-year rate plan and decoupling mechanism proceeding. The WUTC approved a rate increase of $6 million, or 1.7%, effective October 2016 and a second step rate increase of $8 million, or 2.3%, effective September 2017. The WUTC also approved a revenue decoupling mechanism and accelerated depreciation for coal-fueled generation facilities included in Washington rates. As part of the proposed rate plan, PacifiCorp agreed to not file a general rate case in Washington with rates effective earlier than mid-2018.

Idaho

In February 2016, PacifiCorp filed its annual ECAM application with the IPUC requesting recovery of $17 million, consisting primarily of $7 million for deferred net power costs, $6 million for the difference between REC revenues included in base rates and actual REC revenues and $4 million for a Lake Side 2 resource adder. In March 2016, the IPUC approved recovery of $17 million effective April 2016.

In September 2016, a compliance filing was made with the IPUC to update net power costs in base rates. In December 2016, the IPUC approved a $1 million, or 0.4%, decrease in rates effective January 2017.

California

In March 2016, the CPUC approved PacifiCorp's application to recover a $1 million revenue requirement associated with drought-related fire hazard mitigation costs recorded in its catastrophic events memorandum account in 2014. In October 2016, PacifiCorp filed its post test year adjustment mechanism attrition factor for 2017, requesting an overall increase of $1 million, or 1%. In December 2016, the CPUC approved PacifiCorp's request, with new rates effective January 2017.

MidAmerican Energy

In July 2014, the IUB issued an order approving new retail electric base rates for MidAmerican Energy's Iowa customers. The order allowed MidAmerican Energy to increase its base rates over approximately three years with equal annualized increases in revenues of $45 million, or 3.6% over 2012, effective August 2013 and again on January 1, 2015 and 2016, for a total annualized increase of $135 million when fully implemented. In addition to an increase in base rates, the order approved (1) the implementation of two new adjustment clauses related to the recovery of retail energy production costs and certain electric transmission charges (2) seasonal pricing that increased the difference between higher base rates in effect for June through September and base rates applicable to the remaining months of the year; and (3) a revenue sharing mechanism that shares with MidAmerican Energy's customers 80% of revenues related to equity returns above 11% and 100% of revenues related to equity returns above 14%, with the customer portion of any sharing reducing rate base. The changes in seasonal pricing, adjustment clauses and new revenue sharing mechanism were effective with final base rates. MidAmerican Energy recorded a regulatory liability for revenue sharing totaling $30 million in 2016, which reduced rate base in January 2017. Additionally, MidAmerican Energy and the OCA have agreed not to seek or support an increase or decrease in the final base rates to become effective prior to January 1, 2018, unless MidAmerican Energy projects its return on equity to be below 10%.

NV Energy (Nevada Power and Sierra Pacific)

Regulatory Rate Reviews

In June 2016, Sierra Pacific filed an electric regulatory rate review with the PUCN. The filing requested no incremental annual revenue relief. In October 2016, Sierra Pacific filed with the PUCN a settlement agreement resolving most, but not all, issues in the proceeding and reduced Sierra Pacific's electric revenue requirement by $3 million spread evenly to all rate classes. In December 2016, the PUCN approved the settlement agreement and established an additional six MW of net metering capacity under the grandfathered rates, which are those net metering rates that were in effect prior to January 2016; the order establishes cost-based rates and a value-based excess energy credit for customers who choose to install private generation after the six MW limitation is reached. The new rates were effective January 1, 2017. In January 2017, Sierra Pacific filed a petition for reconsideration relating to the creation of the additional six MW of net metering at the grandfathered rates. Sierra Pacific believes the effects of the PUCN decision result in additional cost shifting to non-net metering customers and reduces the stipulated rate reduction for other customer classes.

In June 2016, Sierra Pacific filed a gas regulatory rate review with the PUCN. The filing requested a slight decrease in its incremental annual revenue requirement. In October 2016, Sierra Pacific filed with the PUCN a settlement agreement resolving all issues in the proceeding and reduced Sierra Pacific's gas revenue requirement by $2 million. In December 2016, the PUCN approved the settlement agreement. The new rates were effective January 1, 2017.

EEPR and EEIR

EEPR was established to allow the Nevada Utilities to recover the costs of implementing energy efficiency programs and EEIR was established to offset the negative impacts on revenue associated with the successful implementation of energy efficiency programs. These rates change once a year through the annual DEAA application process based on energy efficiency program budgets prepared by the Nevada Utilities and approved by the PUCN in integrated resource plan proceedings. To the extent the Nevada Utilities' earned rate of return exceeds the rate of return used to set base general rates, the Nevada Utilities' are required to refund to customers EEIR revenue previously collected for that year. In March 2016, the Nevada Utilities each filed an application to reset the EEIR and EEPR and refund the EEIR revenue received in 2015, including carrying charges. In July 2016, the PUCN issued an order accepting a stipulation requiring the Nevada Utilities to refund the 2015 revenue and reset the rates as filed effective October 1, 2016. The current EEIR liability for Nevada Power and Sierra Pacific is $10 million and $2 million, respectively, which is included in current regulatory liabilities on each respective Consolidated Balance Sheet as of December 31, 2016.

Chapter 704B Applications

In May 2015, three customers, including MGM Resorts International ("MGM") and Wynn Las Vegas, LLC ("Wynn"), filed applications to purchase energy from alternative providers of a new electric resource and become distribution only service customers, as allowed by Chapter 704B of the Nevada Revised Statutes. In December 2015, the PUCN granted the applications subject to conditions, including paying an impact fee, on-going charges and receiving approval for specific alternative energy providers and terms. The costs associated with the impact fee and on-going charges were assessed to alleviate the burden on other Nevada Power customers for the applicants' share of previously committed investments and long-term renewable contracts. The impact fee is set on a case-by-case basis by the PUCN and at a level designed such that the remaining customers are not subjected to increased costs. In December 2015, the applicants filed petitions for reconsideration. In January 2016, the PUCN granted reconsideration and updated some of the terms, including removing a limitation related to energy purchased indirectly from NV Energy. In June 2016, MGM and Wynn made the required compliance filings and the PUCN issued orders allowing the customers to acquire electric energy and ancillary services from another energy supplier and become distribution only service customers of Nevada Power. The third customer did not proceed with purchasing energy from alternative providers. In September 2016, MGM and Wynn paid impact fees totaling $97 million. In October 2016, MGM and Wynn became distribution only service customers and started procuring energy from another energy supplier. In December 2016, as contemplated in the PUCN order, the impact fees were increased $2 million to reflect final energy costs for MGM and Wynn.

In July 2016, one Sierra Pacific retail electric customer filed an application with the PUCN to purchase energy from alternative providers of a new electric resource and become a distribution only service customer. In September 2016, that customer withdrew its application.

In September 2016, Switch, Ltd. ("Switch"), a customer of the Nevada Utilities, filed an application with the PUCN to purchase energy from alternative providers of a new electric resource and become a distribution only service customer of Nevada Power and Sierra Pacific. In December 2016, the PUCN approved a stipulation agreement that allowed Switch to purchase energy from alternative providers subject to conditions, including paying an impact fee in the Nevada Power service territory. Switch has provided notice that it intends to proceed with purchasing energy from alternative providers. In November 2016, another customer of the Nevada Utilities filed a similar application with the PUCN.

Net Metering

Nevada enacted Senate Bill 374 ("SB 374") on June 5, 2015. The legislation required the Nevada Utilities to prepare cost-of-service studies and propose new rules and rates for customers who install distributed, renewable generating resources. In July 2015, the Nevada Utilities made filings in compliance with SB 374 and the PUCN issued final orders December 23, 2015.

The final orders issued by the PUCN establish separate rate classes for customers who install distributed, renewable generating facilities. The establishment of separate rate classes recognizes the unique characteristics, costs and services received by these partial requirements customers. The PUCN also established new, cost-based rates or prices for these new customer classes, including increases in the basic service charge and related reductions in energy charges. Finally, the PUCN established a separate value for compensating customers who produce and deliver excess energy to the Nevada Utilities. The valuation will consider eleven factors, including alternatives available to the Nevada Utilities. The PUCN established a gradual, five-step process for transition over four years to the new, cost-based rates.

In January 2016, the PUCN denied requests to stay the order issued December 23, 2015. The PUCN also voted to reopen the evidentiary proceeding to address the application of new net metering rules for customers who applied for net metering service before the issuance of the final order. In February 2016, the PUCN affirmed most of the provisions of the December 23, 2015 order and adopted a twelve-year transition plan for changing rates for net metering customers to cost-based rates for utility services and value-based pricing for excess energy. Subsequently, two solar industry interest groups filed petitions for judicial review of the PUCN order issued in February 2016. The petitions request that the court either modify the PUCN order or direct the PUCN to modify its decision in a manner that would maintain rates and rules of service applicable to net metering as existed prior to the December 23, 2015 order of the PUCN. Two of the three petitions filed by the solar industry interest groups have been dismissed. In September 2016, the state district court issued an order in the third petition. The court concluded that the PUCN failed to provide existing net metering customers adequate legal notice of the proceeding. The court affirmed the PUCN's decision to establish new net energy metering rates and apply those to new net metering customers. The Nevada state district court decision was appealed to the Nevada Supreme Court.

In addition, a referendum was filed in Nevada to modify the statutes applicable to net metering. This referendum was challenged in Nevada state district court and the court determined the referendum was not consistent with the Nevada Constitution. The Nevada state district court decision was appealed to the Nevada Supreme Court. In August 2016, the Nevada Supreme Court upheld the Nevada state district court decision.

In July 2016, the Nevada Utilities filed applications with the PUCN to revert back to the original net metering rates for a period of twenty years for customers who installed or had an active application for distributed, renewable generating facilities as of December 31, 2015. In September 2016, the PUCN issued an order accepting the stipulation and approved the applications as modified by the stipulation. In December 2016, as a part of Sierra Pacific's regulatory rate review, the PUCN issued an order establishing an additional six MWs of net metering under the grandfathered rates in the Sierra Pacific service territory; the order establishes cost-based rates and a value-based excess energy credit for customers who choose to install private generation after the six MW limitation is reached.

Emissions Reduction and Capacity Replacement Plan

Consistent with the Emissions Reduction and Capacity Replacement Plan ("ERCR Plan"), Nevada Power acquired a 272-MW natural gas co-generating facility in 2014, acquired a 210-MW natural gas peaking facility in 2014, constructed a 15-MW solar photovoltaic facility in 2015 and contracted two renewable power purchase agreements with 100-MW solar photovoltaic generating facilities in 2015. In February 2016, Nevada Power solicited proposals to acquire 35 MW of nameplate renewable energy capacity to be owned by Nevada Power. Nevada Power did not enter into any agreements to acquire the 35 MW of nameplate renewable energy capacity; however, it has the option to acquire the 35 MW in the future under the ERCR Plan, subject to PUCN approval. In addition, Nevada Power was granted approval to purchase the remaining 130 MW of the Silverhawk natural gas-fueled combined cycle generating facility. In June 2016, Nevada Power executed a long-term power purchase agreement for 100 MW of nameplate renewable energy capacity in Nevada. In December 2016, the order was approved. In addition the order approved the early retirement of Reid Gardner Unit 4 in the first quarter of 2017. These transactions are related to Nevada Power's compliance with Senate Bill No. 123, resulting in the retirement of 812 MW of coal-fueled generation by 2019.

IRP

In July 2016, Sierra Pacific filed its statutorily required IRP. In August 2016, Nevada Power filed an amendment to its related IRP. As a part of the filings, the Nevada Utilities sought PUCN authorization to acquire the South Point Energy Center, a 504-MW combined-cycle generating facility located in Arizona. In December 2016, the PUCN denied the acquisition of this facility. In January 2017, Nevada Power filed a petition for reconsideration relating to the acquisition of South Point Energy Center. In February 2017, the PUCN affirmed the denial of the acquisition of South Point Energy Center.

Kern River

In December 2016, Kern River filed a Stipulation and Agreement of Settlement with the FERC to establish an alternative set of rates for customers that extend service associated with Kern River’s original system and 2002 expansion, 2003 expansion and 2010 expansion projects. The proposal provides a lower rate option to customers, improves the likelihood of re-contracting expiring capacity and extends recovery of Kern River’s rate base. Under the proposal, customers will have the option to stay with currently established rates or choose the alternative lower rates. The reduction in rates is accomplished by extending the rate term to 25 years instead of the current term of 10 or 15 years, resulting in rates that are 9% to 26% lower than currently established rates. Kern River received FERC approval of the stipulation in January 2017.

ALP

General Tariff Applications

In November 2014, ALP filed a general tariff application ("GTA") requesting 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. ALP amended the GTA in June 2015 to propose transmission tariff relief measures for customers and modifications to its capital structure. ALP also amended and updated the GTA in October 2015, reducing the requested revenue requirements to C $672 million for 2015 and C$704 million for 2016. In May 2016, the AUC issued its decision pertaining to the 2015-2016 GTA. ALP filed its 2015-2016 GTA compliance filing in July 2016 to comply with the AUC's decision.

The compliance filing requested the AUC to approve revenue requirements of C$599 million for 2015 and C$685 million for 2016. The decreased revenue requirements requested in the compliance filing, as compared to the 2015-2016 GTA filing updated in October 2015, were primarily due to the AUC approval of ALP's:

- Proposed immediate tariff relief of C$415 million for customers for 2015 and 2016, through (i) the discontinuance of construction work-in-progress ("CWIP") in rate base and the return to AFUDC accounting effective January 1, 2015, resulting in a C$82 million reduction of revenue requirement and the refund of C$277 million previously collected as CWIP in rate base as part of ALP's transmission tariffs during 2011-2014 less related returns of C$12 million and (ii) a change to the flow through method for calculating income taxes for 2016, resulting in further tariff relief of C$68 million; and

- Depreciation rates as filed, but reduced most of ALP's salvage rates to 2014 levels, which resulted in a reduction of revenue of about C$87 million over two years.

In October 2016, ALP updated its 2015-2016 GTA compliance filing to reflect the impacts of the generic cost of capital decision issued in October 2016. The update requested the AUC to approve ALP's revenue requirement of C$688 million for 2016, an increase of C$3 million from the previously requested C$685 million. The requested 2015 revenue requirement remained unchanged.

In December 2016, the AUC issued its decision with respect to ALP’s 2015-2016 GTA compliance filing. The AUC found that ALP has either complied with or the AUC has otherwise relieved ALP from its compliance with all its directions in its decision except for Directive 47, which dealt with the determination of the refund for previously collected CWIP-in-rate base and all related amounts. In its original compliance filing, ALP had proposed to separately determine the refund of CWIP-in-rate base and the recapitalization of AFUDC to achieve revenue neutrality for ratepayers and ALP. Instead, the AUC has directed ALP to re-calculate the impact of removing CWIP-in-rate base and re-capitalize AFUDC for each of the years 2011 to 2014, and in each year include the accumulated net return and related impacts in no cost capital. In January 2017, ALP filed its second compliance filing as directed by the AUC and requested a technical conference to explain the technical aspects of the filing. The outcome of the compliance filing process is not expected to materially impact the CWIP-in-rate base refund amount.

Once the AUC approves ALP’s compliance filing, final transmission tariff rates for the 2015 and 2016 test years will be set, subject to further adjustment through the deferral account reconciliation process.

ALP updated and refiled its 2017-2018 GTA in August 2016 to reflect the findings and conclusions of the AUC in its 2015-2016 GTA decision issued in May 2016. In October 2016, ALP amended its 2017-2018 GTA to reflect the impacts of the generic cost of capital decision issued in October 2016 and other updates and revisions. The amendment requests the AUC to approve ALP's revenue requirement of C$891 million for 2017 and C$919 million for 2018. In November 2016, the AUC approved the 2017 interim refundable transmission tariff at C$70 million per month effective January 2017. In December 2016, the AUC approved ALP's request to enter into a negotiated settlement process. In January 2017, the parties successfully reached a negotiated settlement on all aspects of ALP’s 2017-2018 GTA. In February 2017, ALP filed with the AUC the 2017-2018 negotiated settlement application for approval. The application consists of negotiated reductions of C$16 million of operating expenses and C$40 million of transmission maintenance and information technology capital expenditures over the two years, as well as increase to miscellaneous revenue of C$3 million. These reductions resulted in a C$24 million, or 1.3%, net decrease to the two-year total revenue requirement applied for in ALP’s 2017-2018 GTA amendment filed in October 2016. In addition, ALP proposed to provide significant tariff relief through the refund of previously collected accumulated depreciation surplus of C$130 million (C$125 million net of other related impacts). The negotiated settlement agreement also provides for additional potential reductions over the two years through a 50/50 cost savings sharing mechanism.

The total tariff relief proposed in the 2015-2016 GTA compliance filing and the 2017-2018 GTA for ALP's customers totals approximately C$600 million over the 2015-2018 period.

2016 Generic Cost of Capital Proceeding

In April 2015, the AUC opened a new generic cost of capital proceeding to set the deemed capital structure and generic return on equity for 2016 and 2017. The AUC released its decision on this proceeding in October 2016, setting the deemed capital structure and generic return on equity for 2016 and 2017. The AUC set the return on equity at 8.3% for 2016 and 8.5% for 2017. ALP's equity ratio was set at 37% for 2016 and 2017. The AUC set deemed common equity ratios for each regulated utility that are consistent with credit ratings in the A category on a stand-alone basis and determined that company specific adjustments were not required for ALP's large capital build program. The AUC also concluded that there was a directional increase in generic business risk, mainly due to concerns with the principles reflected in the Utility Asset Disposition ("UAD") decision.

Deferral Account Reconciliation Application

In June 2016, the AUC issued its decision in relation to the 2012-2013 deferral accounts reconciliation application. Through its decision, the AUC approved C$1.9 billion of the total C$2.0 billion of capital projects included in the application with project costs of C$109 million deferred to a future hearing. In August 2016, ALP filed its 2012-2013 deferral accounts reconciliation compliance filing with the AUC to reflect the findings, conclusions and directions arising from the AUC's decision. In December 2016, the AUC approved the charge of C$59 million to the AESO as requested in the amended compliance filing.

Direct Assigned Capital Deferral Account (DACDA) filing

In the December 2016 compliance decision for the 2012-2013 DACDA, the AUC recognized the imbalance between the projects proposed to be in ALP's 2014 and 2015 DACDAs and stated it was willing to consider a proposal by ALP to shift certain 2015 projects to its 2014 DACDA. In January 2017, ALP filed a proposal with the AUC to include six projects previously in its 2015 DACDA, approximately C$1 billion of additions, to ALP's 2014 DACDA. In February 2017, the AUC approved ALP's proposal.

Appeals of Recent AUC *Decisions*

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 return on equity applicable to all utilities to 8.30% from the previously approved placeholder rate of 8.75% and decreased ALP's equity ratio from 37% to 36% for the years 2013, 2014 and 2015. ALP and other utilities had applied to the Alberta Court of Appeal for leave to appeal this decision; however, a decision not to proceed was made in the first quarter of 2016.

In November 2013, the AUC issued its UAD decision in which it concluded, among other things, that in the case of the extraordinary retirement of an asset before it is fully depreciated, under or over recovery of capital investment on an extraordinary retirement should be borne by the utility and its shareholders. ALP and other utilities appealed the AUC's UAD decision to the Alberta Court of Appeal, which was dismissed in September 2015. In November 2015, ALP, Epcor and Enmax, filed a joint leave application to the Supreme Court of Canada for appeal of the Alberta Court of Appeal's UAD decision. The Supreme Court of Canada dismissed the appeal in April 2016.

In its November 2013 decision pertaining to ALP's 2013-2014 GTA, 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. ALP requested approval of the capital project expenditures, including the new competitively bid EPCM rates, in its 2012-2013 direct assigned capital deferral account filing. The AUC approved the EPCM rates applied for as part of that filing as prudent in June 2016.

BHE U.S. Transmission

A significant portion of ETT's revenues are based on interim rate changes that can be filed twice annually and are subject to review and possible true-up in the next filed base regulatory rate review. In October 2016, the most recent interim filing was approved which set total annual revenue requirements at $373 million and a rate base of $2.7 billion. In a November 2015 open meeting at the PUCT, ETT committed to file a base regulatory rate review by February 2017. In January 2017, the PUCT approved ETT's request to suspend the base regulatory rate review filing and set ETT's annual revenue requirement to $327 million, effective March 2017. Results of a base regulatory rate review would be prospective except for any deemed disallowance by the PUCT of the transmission investment since the initial base regulatory rate review in 2007. A refund of interim transmission rates would reduce future net income and cash flows. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

ENVIRONMENTAL LAWS AND REGULATIONS

Each Registrant is subject to federal, state, local and foreign laws and regulations regarding air and water quality, RPS, 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 each Registrant'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. Each Registrant believes it is in material compliance with all applicable laws and regulations, although many laws and regulations are subject to interpretation that may ultimately be resolved by the courts. Refer to "Liquidity and Capital Resources" of each respective Registrant in Item 7 of this Form 10-K for discussion of each Registrant's forecast environmental-related capital expenditures.

Clean Air Act Regulations

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

National Ambient Air Quality Standards

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

In October 2015, the EPA revised the national ambient air quality standard for ground level ozone, strengthening the standard from 75 parts per billion to 70 parts per billion. It is anticipated that the EPA will make attainment/nonattainment designations for the revised standards by late 2017. Nonattainment areas will have until 2020 to late 2037 to meet the standard. 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 relevant Registrant.

Until the 2015 standard is fully implemented, the EPA continues to implement the 2008 ozone standards. The Upper Green River Basin Area in Wyoming, including all of Sublette and portions of Lincoln and Sweetwater Counties, were proposed to be designated as nonattainment for the 2008 ozone standard. When the final designations were released in April 2012, portions of Lincoln and Sweetwater Counties and Sublette County were determined to be in marginal nonattainment. While PacifiCorp's Jim Bridger plant is located in Sweetwater County, it is not in the portion of the designated nonattainment area and has not been impacted by the 2012 designation. In December 2012, the EPA approved Nevada's request to re-designate Clark County to be in attainment for the 1997 eight-hour ozone standard while also approving Clark County's plan to maintain compliance with the standard through 2022. However, Clark County remains unclassifiable for the 2008 ozone standard. If the EPA revises the ozone standard to be more stringent, it is possible that Clark County will again be designated as nonattainment for ozone, creating the potential to impact Nevada Power's Clark, Sun Peak, Las Vegas, Lenzie, Silverhawk, Harry Allen, Higgins, and Goodsprings generating facilities. However, until such time as the 2015 standard is implemented or Clark County is classified as nonattainment for the 2008 or 2015 standards, any potential impacts cannot be determined.

In January 2010, the EPA finalized a one-hour air quality standard for nitrogen dioxide at 100 parts per billion. In February 2012, the EPA published final designations indicating that based on air quality monitoring data, all areas of the country are designated as "unclassifiable/attainment" for the 2010 nitrogen dioxide national ambient air quality standard.

In June 2010, the EPA finalized a new national ambient air quality standard for sulfur dioxide. Under the 2010 rule, areas must meet a one-hour standard of 75 parts per billion utilizing a three-year average. The rule utilizes source modeling in addition to the installation of ambient monitors where sulfur dioxide emissions impact populated areas. Attainment designations were due by June 2012; however, citing a lack of sufficient information to make the designations, the EPA did not issue its final designations until July 2013 and determined, at that date, that a portion of Muscatine County, Iowa was in nonattainment for the one-hour sulfur dioxide standard. MidAmerican Energy's Louisa coal-fueled generating facility is located just outside of Muscatine County, south of the violating monitor. In its final designation, the EPA indicated that it was not yet prepared to conclude that the emissions from the Louisa coal-fueled generating facility contribute to the monitored violation or to other possible violations, and that in a subsequent round of designations, the EPA will make decisions for areas and sources outside Muscatine County. MidAmerican Energy does not believe a subsequent nonattainment designation will have a material impact on the Louisa coal-fueled generating facility. Although the EPA's July 2013 designations did not impact PacifiCorp's nor the Nevada Utilities' generating facilities, the EPA's assessment of sulfur dioxide area designations will continue with the deployment of additional sulfur dioxide monitoring networks across the country.

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 2010 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 submitted documentation to the EPA in April 2016 supporting its recommendation that Des Moines, Wapello and Woodbury Counties be designated as being in attainment of the standard. In July 2016, the EPA's final designations were published in the Federal Register indicating portions of Muscatine County, Iowa were in nonattainment with the 2010 sulfur dioxide standard, Woodbury County, Iowa was unclassifiable, and Des Moines and Wapello Counties were unclassifiable/attainment.

In January 2017, the states of Utah and Wyoming submitted a combination of modeling and a proposed monitoring plan to the EPA that will be used to determine if areas around PacifiCorp's coal facilities located within those states are in attainment with the one-hour sulfur dioxide standard. It is expected that the combination of modeling and monitoring will demonstrate that the areas surrounding PacifiCorp's coal facilities are in attainment with the standard.

In December 2012, the EPA finalized more stringent fine particulate matter national ambient air quality standards, reducing the annual standard from 15 micrograms per cubic meter to 12 micrograms per cubic meter and retaining the 24-hour standard at 35 micrograms per cubic meter. The EPA did not set a separate secondary visibility standard, choosing to rely on the existing secondary 24-hour standard to protect against visibility impairment. In December 2014, the EPA issued final area designations for the 2012 fine particulate matter standard. Based on these designations, the areas in which the relevant Registrant operates generating facilities have been classified as "unclassifiable/attainment." Unless additional monitoring suggests otherwise, the relevant Registrant does not anticipate that any impacts of the revised standard will be significant.

In December 2014, the Utah SIP for fine particulate matter was adopted by the Utah Air Quality Board. PacifiCorp's Lake Side and Gadsby generating facilities operate within nonattainment areas for fine particulate matter; however, the SIP did not impose significant new requirements on PacifiCorp's impacted generating facilities, nor did the EPA's comments on the Utah SIP identify requirements for PacifiCorp's existing generating facilities that would have a material impact on its consolidated financial results.

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

Mercury and Air Toxics Standards

In March 2011, the EPA proposed a rule that requires coal-fueled generating facilities to reduce mercury emissions and other hazardous air pollutants through the establishment of "Maximum Achievable Control Technology" standards. The final MATS became effective on April 16, 2012, and required that new and existing coal-fueled generating facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. Existing sources were required to comply with the new standards by April 16, 2015 with the potential for individual sources to obtain an extension of up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls or for transmission system reliability reasons. The relevant Registrants have completed emission reduction projects to comply with the final rule's standards for acid gases and non-mercury metallic hazardous air pollutants.

MidAmerican Energy retired certain coal-fueled generating units as the least-cost alternative to comply with the MATS. Walter Scott, Jr. Energy Center Units 1 and 2 were retired in 2015, and George Neal Energy Center Units 1 and 2 were retired in April 2016. A fifth unit, Riverside Generating Station, was limited to natural gas combustion in March 2015.

PacifiCorp retired its two coal-fueled generating units at the Carbon Facility in 2015 to comply with the MATS requirements and other environmental regulations as well as in conformance with Utah's Regional Haze SIP. Refer to the Regional Haze section below for additional requirements regarding the Carbon Facility.

Numerous lawsuits have been filed in the D.C. Circuit challenging the 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. In December 2015, the D.C. Circuit issued an order remanding the rule to the EPA, without vacating the rule. As a result, the relevant Registrants continue to have a legal obligation under the MATS rule and the respective permits issued by the states in which each respective Registrant operates to comply with the MATS rule, including operating all emissions controls or otherwise complying with the MATS requirements.

Cross-State Air Pollution Rule

The EPA promulgated an initial rule in March 2005 to reduce emissions of nitrogen oxides and sulfur dioxide, precursors of ozone and particulate matter, from down-wind sources in the eastern United States, including Iowa, to reduce emissions by implementing a plan based on a market-based cap-and-trade system, emissions reductions, or both. After numerous appeals, the Cross-State Air Pollution Rule ("CSAPR") was promulgated to address interstate transport of sulfur dioxide and nitrogen oxides emissions in 27 eastern and Midwestern states.

The first phase of the rule was implemented January 1, 2015. In November 2015, the EPA released a proposed rule that would further reduce nitrogen oxides emissions in 2017. The final rule was published in the Federal Register in October 2016. The rule requires additional reductions in nitrogen oxides emissions beginning in May 2017. On December 23, 2016, a lawsuit was filed against the EPA in the D.C. Circuit over the final CSAPR "update" rule.

MidAmerican Energy has installed emissions controls at its coal-fueled generating facilities to comply with the CSAPR and may purchase emissions allowances to meet a portion of its compliance obligations. The cost of these allowances is subject to market conditions at the time of purchase and historically has not been material. MidAmerican Energy believes that the controls installed to date are consistent with the reductions to be achieved from implementation of the rule and does not anticipate that any impacts of the CSAPR update will be significant.

MidAmerican Energy operates natural gas-fueled generating facilities in Iowa and BHE Renewables operates natural gas-fueled generating facilities in Texas, Illinois and New York, which are subject to the CSAPR. However, the provisions are not anticipated to have a material impact on Berkshire Hathaway Energy or MidAmerican Energy. None of PacifiCorp's, Nevada Power's or Sierra Pacific's generating facilities are subject to the CSAPR. However, in a Notice of Data Availability published in the January 6, 2017, Federal Register, the EPA provided preliminary estimates of which upwind states may have linkages to downwind states experiencing ozone levels at or exceeding the 2015 ozone national ambient air quality standard of 70 parts per billion, and, using similar methodology to that in the CSAPR, indicated that Utah and Wyoming could have an obligation under the "good neighbor" provisions of the Clean Air Act to reduce nitrogen oxides emissions.

Regional Haze

The EPA's Regional Haze Rule, finalized in 1999, requires states to develop and implement plans to improve visibility in designated federally protected areas ("Class I areas"). Some of PacifiCorp's coal-fueled generating facilities in Utah, Wyoming, Arizona and Colorado and certain of Nevada Power's and Sierra Pacific's fossil-fueled generating facilities are subject to the Clean Air Visibility Rules. In accordance with the federal requirements, states are required to submit SIPs that address emissions from sources subject to best available retrofit technology ("BART") requirements and demonstrate progress towards achieving natural visibility requirements in Class I areas by 2064.

The state of Utah issued a regional haze SIP requiring the installation of sulfur dioxide, nitrogen oxides and particulate matter controls on Hunter Units 1 and 2, and Huntington Units 1 and 2. In December 2012, the EPA approved the sulfur dioxide portion of the Utah regional haze SIP and disapproved the nitrogen oxides and particulate matter portions. Certain groups appealed the EPA's approval of the sulfur dioxide portion and oral argument was heard before the United States Court of Appeals for the Tenth Circuit ("Tenth Circuit") in March 2014. In October 2014, the Tenth Circuit upheld the EPA's approval of the sulfur dioxide portion of the SIP. The state of Utah and PacifiCorp filed petitions for administrative and judicial review of the EPA's final rule on the BART determinations for the nitrogen oxides and particulate matter portions of Utah's regional haze SIP in March 2013. 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 completed an alternative BART analysis for Hunter Units 1 and 2, and Huntington Units 1 and 2. The alternative BART analysis and revised regional haze SIP were submitted in June 2015 to the EPA for review and proposed action after a public comment period. The revised regional haze SIP included a state-enforceable requirement to cease operation of the Carbon Facility by August 15, 2015. PacifiCorp retired the Carbon Facility in December 2015. In January 2016, the EPA published two alternative proposals to either approve the Utah SIP as written or reject the Utah SIP relating to nitrogen oxides controls and require the installation of selective catalytic reduction ("SCR") controls at Hunter Units 1 and 2 and Huntington Units 1 and 2 within five years. EPA's final action on the Utah regional haze SIP was effective August 4, 2016. The EPA approved in part and disapproved in part the Utah regional haze SIP and issued a federal implementation plan ("FIP") requiring the installation of SCR controls at Hunter Units 1 and 2 and Huntington Units 1 and 2 within five years of the effective date of the rule. PacifiCorp and other parties have filed requests with the EPA to reconsider and stay that decision, and have also filed motions for stay and petitions for review with the Tenth Circuit asking the court to overturn the EPA’s actions. The EPA has yet to respond to the administrative action filings. The Tenth Circuit has established procedural schedules for review of the stay request and the appeal, with filings in the stay proceeding having been concluded and awaiting action by the Tenth Circuit.

The state of Wyoming issued two regional haze SIPs requiring the installation of sulfur dioxide, nitrogen oxides and particulate matter controls on certain PacifiCorp coal-fueled generating facilities in Wyoming. The EPA approved the sulfur dioxide SIP in December 2012 and the EPA's approval was upheld on appeal by the Tenth Circuit in October 2014. In addition, the EPA initially proposed in June 2012 to disapprove portions of the nitrogen oxides and particulate matter SIP and instead issue a FIP. The EPA withdrew its initial proposed actions on the nitrogen oxides and particulate matter SIP and the proposed FIP, published a re-proposed rule in June 2013, and finalized its determination in January 2014, which aligns more closely with the SIP proposed by the state of Wyoming. The EPA's final action on the Wyoming SIP approved the state's plan to have PacifiCorp install low-nitrogen oxides burners at Naughton Units 1 and 2, SCR controls at Naughton Unit 3 by December 2014, SCR controls at Jim Bridger Units 1 through 4 between 2015 and 2022, and low-nitrogen oxides burners at Dave Johnston Unit 4. The EPA disapproved a portion of the Wyoming SIP and issued a FIP for Dave Johnston Unit 3, where it required the installation of SCR controls by 2019 or, in lieu of installing SCR controls, a commitment to shut down Dave Johnston Unit 3 by 2027, its currently approved depreciable life. The EPA also disapproved a portion of the Wyoming SIP and issued a FIP for the Wyodak coal-fueled generating facility ("Wyodak Facility"), requiring the installation of SCR controls within five years (i.e., by 2019). The EPA action became final on March 3, 2014. PacifiCorp filed an appeal of the EPA's final action on the Wyodak Facility in March 2014. The state of Wyoming also filed an appeal of the EPA's final action, as did the Powder River Basin Resource Council, National Parks Conservation Association and Sierra Club. In September 2014, the Tenth Circuit issued a stay of the March 2019 compliance deadline for the Wyodak Facility, pending further action by the Tenth Circuit in the appeal. In June 2014, the Wyoming Department of Environmental Quality issued a revised BART permit allowing Naughton Unit 3 to operate on coal through 2017 and providing for natural gas conversion of the unit in 2018; in October 2016, an application was filed with the Wyoming Department of Environmental Quality requesting a revision of the dates for the end of coal firing and the start of gas firing for Naughton Unit 3 to align with the requirements of the Wyoming SIP. The Wyoming Department of Environmental Quality has taken public comment on, but not yet approved, Naughton Unit 3 to cease coal firing no later than January 30, 2019, and complete the gas conversion by June 30, 2019. In its final action, the EPA indicated it supported the conversion of the unit to natural gas as its fuel source and would expedite action relative to consideration of the natural gas conversion once the state of Wyoming submitted the requisite SIP amendment; nonetheless, Naughton Unit 3 natural gas conversion, should it ultimately be pursued, remains subject to final approval by the EPA.

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 FIP for the disapproved portions requiring SCR 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, permit applications and studies were submitted to amend the Cholla 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. The EPA issued its proposed action to approve amendments to the Arizona regional haze SIP, which were published in the Federal Register in July 2016. The EPA's final action to approve the amendments to the Arizona regional haze SIP was issued January 13, 2017, but has not yet been published in the Federal Register.

The state of Colorado regional haze SIP requires SCR controls at Craig Unit 2 and Hayden Units 1 and 2, in which PacifiCorp has ownership interests. Each of those regional haze compliance projects are either already in service or currently being constructed. In addition, in February 2015, the state of Colorado finalized an amendment to its regional haze SIP relating to Craig Unit 1, in which PacifiCorp has an ownership interest, to require the installation of SCR controls by 2021. The EPA has yet to act on the amended Colorado SIP. In September 2016, the owners of Craig Units 1 and 2 reached an agreement with state and federal agencies and certain environmental groups that were parties to the previous settlement requiring SCR to retire Unit 1 by December 31, 2025, in lieu of SCR installation, or alternatively to remove the unit from coal-fueled service in 2021 and implement a natural gas conversion by 2023, in lieu of SCR installation. The terms of the agreement were approved by the Colorado Air Quality Board in December 2016. The terms of the agreement will be incorporated into an amended Colorado regional haze SIP in 2017, which upon approval, will be submitted to the EPA for its review and approval process.

Until the EPA takes final action in each state and decisions have been made in the pending appeals, PacifiCorp, cannot fully determine the impacts of the Regional Haze Rule on its respective generating facilities.

The Navajo Generating Station, in which Nevada Power is a joint owner with an 11.3% ownership share, is also a source that is subject to the regional haze BART requirements. In January 2013, the EPA announced a proposed FIP addressing BART and an alternative for the Navajo Generating Station that includes a flexible timeline for reducing nitrogen oxides emissions. Nevada Power, along with the other owners of the facility, have been reviewing the EPA's proposal to determine its impact on the viability of the facility's future operations. The land lease for the Navajo Generating Station is subject to renewal in 2019. Renewal of the lease will require completion of an Environmental Impact Statement as well as a renewal of the fuel supply agreement. In September 2013, the EPA issued a supplemental proposal that included another BART alternative called the Technical Work Group Alternative, which is based on a proposal submitted to the EPA by a group of Navajo Generating Station stakeholders. The EPA accepted comments on the various alternatives through January 6, 2014 and, in August 2014, the EPA announced it had approved the final plan for the Navajo Generating Station, including the reduction of emissions of nitrogen oxides by approximately 80% through the retirement of one unit, or the curtailment of generation equivalent to one unit, in 2019 and installation of SCR controls at the other two units by 2030. In October 2014, several groups filed an appeal of the EPA's decision in the Ninth Circuit; oral arguments were heard by the Ninth Circuit on November 18, 2016. The Hopi Tribe was initially part of the larger group appeal but their challenge was subsequently severed from that appeal and is proceeding separately. Until such time as additional action is taken by the Ninth Circuit and the uncertainties regarding lease and agreement renewal terms for the Navajo Generating Station are addressed, Nevada Power cannot predict the outcome of this matter. Nevada Power filed the ERCR Plan in May 2014 that proposed to eliminate its ownership participation in the Navajo Generating Station in 2019, which was approved by the PUCN.

Climate Change

In December 2015, an international agreement was negotiated by 195 nations to create a universal framework for coordinated action on climate change in what is referred to as the Paris Agreement. The Paris Agreement reaffirms the goal of limiting global temperature increase well below 2 degrees Celsius, while urging efforts to limit the increase to 1.5 degrees Celsius; establishes commitments by all parties to make nationally determined contributions and pursue domestic measures aimed at achieving the commitments; commits all countries to submit emissions inventories and report regularly on their emissions and progress made in implementing and achieving their nationally determined commitments; and commits all countries to submit new commitments every five years, with the expectation that the commitments will get more aggressive. In the context of the Paris Agreement, the United States agreed to reduce greenhouse gas emissions 26% to 28% by 2025 from 2005 levels. After more than 55 countries representing more than 55% of global greenhouse gas emissions submitted their ratification documents, the Paris Agreement became effective November 4, 2016. Under the terms of the Paris Agreement, ratifying countries are bound for a three-year period and must provide one-year's notice of their intent to withdraw. The cornerstone of the United States' commitment is the Clean Power Plan which was finalized by the EPA in 2015.

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. On August 3, 2015, the EPA issued 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" 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. The new source performance standards have been appealed to the D.C. Circuit and oral argument is scheduled to be heard April 17, 2017. However, despite the pendency of the appeal, any new fossil-fueled generating facilities constructed by the relevant Registrants 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 the "Best System of Emission Reduction." In August 2015, the final Clean Power Plan was released, which established the Best System of Emission Reduction as including: (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 in August 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 public comment period on the draft federal plan and proposed model trading rules closed January 21, 2016. States were required to submit their initial implementation plans by September 2016 but could request an extension to September 2018. However, on February 9, 2016, the United States Supreme Court ordered that the EPA's emission guidelines for existing sources be stayed pending the disposition of the challenges to the rule in the D.C. Circuit and any action on a writ of certiorari before the U.S. Supreme Court. Oral argument was heard before the full D.C. Circuit (with the exception of Chief Judge Merrick Garland) on September 27, 2016, and the court has not yet issued its decision. The full impacts of the final rule or the federal plan on the Registrants cannot be determined until the outcome of the pending litigation and subsequent appeals, the outcome of any issues should the case be remanded for further action by the EPA, the development and implementation of state plans, and finalization of the federal plan. 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.

In the absence of comprehensive climate legislation or regulation, the Registrants have continued to invest in lower- and non-carbon generating resources and to operate in an environmentally responsible manner. In July 2015, BHE signed the American Business Act on Climate pledge, in which BHE pledged to build on the Company's combined investment of more than $15 billion in renewable energy generation under construction and in operation through 2014 by investing up to an additional $15 billion. Components of BHE's pledge include:

- Pursue the construction of an additional 552 MW of new wind-powered generation in Iowa, increasing MidAmerican Energy's generating portfolio to more than 4,000 MW of wind, which is forecast to be equivalent to 63 percent of its Iowa retail sales in 2017. MidAmerican Energy surpassed its Climate Pledge commitments in 2016 and is currently proceeding with the construction of an additional 2,000 MW of new wind-powered generation in Iowa. When complete, MidAmerican Energy’s wind portfolio will include more than 6,000 MW, which is forecast to be equivalent to 89 percent of its Iowa retail sales in 2020. MidAmerican Energy owns the largest portfolio of wind-powered generating capacity in the United States among rate-regulated utilities.
- Retire more than 75 percent of the Nevada Utilities' coal-fueled generating capacity in Nevada by 2019.
- Add more than 1,000 MW of incremental solar and wind capacity through long-term power purchase agreements to PacifiCorp's owned 1,030 MW of wind-powered generating capacity. PacifiCorp owns the second largest portfolio of wind-powered generating capacity in the United States among rate-regulated utilities. PacifiCorp’s Climate Pledge commitments were met December 2016. The new capacity brings PacifiCorp’s non-carbon generating capacity to more than 4,500 MW, which is forecast to be equivalent to 22 percent of its retail sales in 2017.
- Invest in transmission infrastructure in the West and Midwest to support the integration of renewable energy onto the grid.
- Support and advance the development of markets in the West to optimize the electric grid, lower costs, enhance reliability and more effectively integrate renewable sources.

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

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

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

Regional and State Activities

Several states have promulgated or otherwise participate in state-specific or regional laws or initiatives to report or mitigate GHG emissions. These are expected to impact the relevant Registrant, and include:

- In June 2013, Nevada Senate Bill 123 ("SB 123") was signed into law. Among other things, SB 123 and regulations thereunder require Nevada Power to file with the PUCN an emission reduction and capacity replacement plan by May 1, 2014. In May 2014, Nevada Power filed its emissions reduction capacity replacement plan. The plan provided for the retirement or elimination of 300 MW of coal generating capacity by December 31, 2014, another 250 MW of coal generating capacity by December 31, 2017, and another 250 MW of coal generating capacity by December 31, 2019, along with replacement of such capacity with a mixture of constructed, acquired or contracted renewable and non-technology specific generating units. The plan also sets forth the expected timeline and costs associated with decommissioning coal-fired generating units that will be retired or eliminated pursuant to the plan. The PUCN has the authority to approve or modify the emission reduction and capacity replacement plan filed by Nevada Power. Given the PUCN may recommend and/or approve variations to Nevada Power's resource plans relative to requirements under SB 123, the specific impacts of SB 123 on Nevada Power cannot be determined.

- Under the authority of California's Global Warming Solutions Act, which includes a series of policies aimed at returning California greenhouse gas emissions to 1990 levels by 2020, the California Air Resources Board adopted a GHG cap-and-trade program with an effective date of January 1, 2012; compliance obligations were imposed on entities beginning in 2013. PacifiCorp is subject to the cap-and-trade program as a retail service provider in California and an importer of wholesale energy into California. In 2015, Governor Jerry Brown issued an executive order to reduce emissions to 40% below 1990 levels by 2030 and 80% by 2050. In September 2016, California Senate Bill 32 was signed into law establishing greenhouse gas emissions reduction targets of 40% below 1990 levels by 2030.

- The states of California, Washington and Oregon have adopted GHG emissions performance standards for base load electricity generating resources. Under the laws in California and Oregon, the emissions performance standards provide that emissions must not exceed 1,100 pounds of carbon dioxide per MWh. Effective April 2013, Washington's amended emissions performance standards provide that GHG emissions for base load electricity generating resources must not exceed 970 pounds of carbon dioxide per MWh. These GHG emissions performance standards generally prohibit electric utilities from entering into long-term financial commitments (e.g., new ownership investments, upgrades, or new or renewed contracts with a term of five or more years) unless any base load generation supplied under long-term financial commitments comply with the GHG emissions performance standards.

- Washington and Oregon enacted legislation in May 2007 and August 2007, respectively, establishing goals for the reduction of GHG emissions in their respective states. Washington's goals seek to (a) reduce emissions to 1990 levels by 2020; (b) reduce emissions to 25% below 1990 levels by 2035; and (c) reduce emissions to 50% below 1990 levels by 2050, or 70% below Washington's forecasted emissions in 2050. Oregon's goals seek to (a) cease the growth of Oregon GHG emissions by 2010; (b) reduce GHG levels to 10% below 1990 levels by 2020; and (c) reduce GHG levels to at least 75% below 1990 levels by 2050. Each state's legislation also calls for state government to develop policy recommendations in the future to assist in the monitoring and achievement of these goals.

- In September 2016, the Washington State Department of Ecology issued a final rule regulating GHG emissions from sources in Washington. The rule regulates greenhouse gases including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride beginning in 2017 with three-year compliance periods thereafter (i.e., 2017-2019, 2020-2022, etc.). Under the rule, the Washington State Department of Ecology will establish a GHG emissions reduction pathway for all covered entities. Covered entities may use emission reduction units, which may be traded with other covered entities, to meet their compliance requirements. PacifiCorp's resources that are covered under the rule include the Chehalis generating facility, which is a natural gas combined-cycle plant located in Washington state.

- The Regional Greenhouse Gas Initiative, a mandatory, market-based effort to reduce GHG emissions in ten Northeastern and Mid-Atlantic states, required, beginning in 2009, the reduction of carbon dioxide emissions from the power sector of 10% by 2018. In May 2011, New Jersey withdrew from participation in the Regional Greenhouse Gas Initiative. Following a program review in 2012, the nine Regional Greenhouse Gas Initiative states implemented a new 2014 cap which was approximately 45% lower than the 2012-2013 cap. The cap is reduced each year by 2.5% from 2015 to 2020. As called for in the 2012 program review, a program review was initiated for 2016 and continues through 2017 with the expectation that states will implement program changes in the fourth control period from 2018 to 2020.

GHG Litigation

Each Registrant closely monitors ongoing environmental litigation applicable to its respective operations. Numerous lawsuits have been unsuccessfully pursued against the industry that attempt to link GHG emissions to public or private harm. The lower courts initially refrained from adjudicating the cases under the "political question" doctrine, because of their inherently political nature. These cases have typically been appealed to federal appellate courts and, in certain circumstances, to the United States Supreme Court. In the U.S. Supreme Court's 2011 decision in the case of American Electric Power Co., Inc., et al. v. Connecticut et al., the court addressed the question of whether federal common law nuisance claims could be maintained against certain electric power companies' for their GHG emissions and require the setting of an emissions cap for the emitters. The court held that the Clean Air Act and the EPA actions it authorizes displace any federal common law right to seek abatement of carbon dioxide emissions from fossil-fuel-fired power plants. Adverse rulings in GHG-related cases could result in increased or changed regulations and could increase costs for GHG emitters, including the Registrants' generating facilities.

The GHG rules, changes to those rules, and the Registrants' compliance requirements are subject to potential outcomes from proceedings and litigation challenging the rules.

Renewable Portfolio Standards

Each state's RPS described below could significantly impact the relevant Registrant's consolidated financial results. Resources that meet the qualifying electricity requirements under each RPS vary from state to state. Each state's RPS requires some form of compliance reporting and the relevant Registrant can be subject to penalties in the event of noncompliance. Each Registrant believes it is in material compliance with all applicable RPS laws and regulations.

Since 1997, NV Energy has been required to comply with a RPS. Current law requires the Nevada Utilities to meet 18% of their energy requirements with renewable resources for 2014, 20% for 2015 through 2019, 22% for 2020 and 2024, and 25% for 2025 and thereafter. The RPS also requires 5% of the portfolio requirement come from solar resources through 2015 and increasing to 6% in 2016. Nevada law also permits energy efficiency measures to be used to satisfy a portion of the RPS through 2025, subject to certain limitations.

Utah's Energy Resource and Carbon Emission Reduction Initiative provides that, beginning in the year 2025, 20% of adjusted retail electric sales of all Utah utilities be supplied by renewable energy, if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions, and for sales avoided as a result of energy efficiency and DSM programs. Qualifying renewable energy sources can be located anywhere within the WECC, and renewable energy credits can be used.

The Oregon Renewable Energy Act ("OREA") provides a comprehensive renewable energy policy and RPS for Oregon. Subject to certain exemptions and cost limitations established in the law, PacifiCorp and other qualifying electric utilities must meet minimum qualifying electricity requirements for electricity sold to retail customers of at least 5% in 2011 through 2014, 15% in 2015 through 2019, and 20% in 2020 through 2024. In March 2016, Oregon Senate Bill No. 1547-B, the Clean Electricity and Coal Transition Plan, was signed into law. Senate Bill No. 1547-B requires that coal-fueled resources are eliminated from Oregon’s allocation of electricity by January 1, 2030, and increases the current RPS target from 25% in 2025 to 50% by 2040. Senate Bill No. 1547-B also implements new REC banking provisions, as well as the following interim RPS targets: 27% in 2025 through 2029, 35% in 2030 through 2034, 45% in 2035 through 2039, and 50% by 2040 and subsequent years. As required by the OREA, the OPUC has approved an automatic adjustment clause to allow an electric utility, including PacifiCorp, to recover prudently incurred costs of its investments in renewable energy generating facilities and associated transmission costs.

Washington's Energy Independence Act establishes a renewable energy target for qualifying electric utilities, including PacifiCorp. The requirements are 3% of retail sales by January 1, 2012 through 2015, 9% of retail sales by January 1, 2016 through 2019 and 15% of retail sales by January 1, 2020 and each year thereafter. In April 2013, Washington State Senate Bill No. 5400 ("SB 5400") was signed into law. SB 5400 expands the geographic area in which eligible renewable resources may be located to beyond the Pacific Northwest, allowing renewable resources located in all states served by PacifiCorp to qualify. SB 5400 also provides PacifiCorp with additional flexibility and options to meet Washington's renewable mandates.

The California 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.

Water Quality Standards

The federal Water Pollution Control Act ("Clean Water Act") establishes the framework for maintaining and improving water quality in the United States through a program that regulates, among other things, discharges to and withdrawals from waterways. The Clean Water Act requires that cooling water intake structures reflect the "best technology available for minimizing adverse environmental impact" to aquatic organisms. After significant litigation, the EPA released a proposed rule under §316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The final rule was released in May 2014, and became effective in October 2014. Under the final rule, existing facilities that withdraw at least 25% of their water exclusively for cooling purposes and have a design intake flow of greater than two million gallons per day are required to reduce fish impingement (i.e., when fish and other aquatic organisms are trapped against screens when water is drawn into a facility's cooling system) by choosing one of seven options. Facilities that withdraw at least 125 million gallons of water per day from waters of the United States must also conduct studies to help their permitting authority determine what site-specific controls, if any, would be required to reduce entrainment of aquatic organisms (i.e., when organisms are drawn into the facility). PacifiCorp and MidAmerican Energy are assessing the options for compliance at their generating facilities impacted by the final rule and will complete impingement and entrainment studies. PacifiCorp's Dave Johnston generating facility and all of MidAmerican Energy's coal-fueled generating facilities, except Louisa, Ottumwa and Walter Scott, Jr. Unit 4, which have water cooling towers, withdraw more than 125 million gallons per day of water from waters of the United States for once-through cooling applications. PacifiCorp's Jim Bridger, Naughton, Gadsby, Hunter and Huntington generating facilities currently utilize closed cycle cooling towers but are designed to withdraw more than two million gallons of water per day. The standards are required to be met as soon as possible after the effective date of the final rule, but no later than eight years thereafter. The costs of compliance with the cooling water intake structure rule cannot be fully determined until the prescribed studies are conducted. In the event that PacifiCorp's or MidAmerican Energy's existing intake structures require modification, the costs are not anticipated to be significant to the consolidated financial statements. Nevada Power and Sierra Pacific do not utilize once-through cooling water intake or discharge structures at any of their generating facilities. All of the Nevada Power and Sierra Pacific generating stations are designed to have either minimal or zero discharge; therefore, they are not impacted by the §316(b) final rule.

In November 2015, the EPA published final effluent limitation guidelines and standards for the steam electric power generating sector which, among other things, regulate the discharge of bottom ash transport water, fly ash transport water, combustion residual leachate and non-chemical metal cleaning wastes. These guidelines, which had not been revised since 1982, were revised in response to the EPA's concerns that the addition of controls for air emissions has changed the effluent discharged from coal- and natural gas-fueled generating facilities. Permitting authorities are required to include the new limits in each impacted facility's discharge permit upon renewal; the new limits must be met as soon as possible, beginning November 1, 2018 and must be implemented by December 31, 2023. Most of the issues raised by this rule are already being addressed through the coal combustion residuals rule and are not expected to impose significant additional requirements on the facilities.

In April 2014, the EPA and the United States Army Corps of Engineers issued a joint proposal to address "Waters of the United States" to clarify protection under the Clean Water Act for streams and wetlands. The proposed rule comes as a result of United States Supreme Court decisions in 2001 and 2006 that created confusion regarding jurisdictional waters that were subject to permitting under either nationwide or individual permitting requirements. The final rule was released in May 2015 but is currently under appeal in multiple courts and a nationwide stay on the implementation of the rule was issued in October 2015. On January 13, 2017, the U.S. Supreme Court granted a petition to address jurisdictional challenges to the rule. Depending on the outcome of the appeal(s), a variety of projects that otherwise would have qualified for streamlined permitting processes under nationwide or regional general permits will be required to undergo more lengthy and costly individual permit procedures based on an extension of waters that will be deemed jurisdictional. However, until the rule is fully litigated and finalized, the Registrants cannot determine whether projects that include construction and demolition will face more complex permitting issues, higher costs or increased requirements for compensatory mitigation.

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 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 of the rule 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. At the time the rule was published in April 2015, MidAmerican Energy owned or operated nine surface impoundments and four landfills that contain coal combustion byproducts. Prior to the effective date of the rule in October 2015, MidAmerican Energy closed or repurposed six surface impoundments to no longer receive coal combustion byproducts. These six impoundments are subject to closure on or before April 2018. At the time the rule was published in April 2015, the Nevada Utilities operated ten evaporative surface impoundments and two landfills that contained coal combustion byproducts. Prior to the effective date of the rule in October 2015, the Nevada Utilities closed four of the surface impoundments, four impoundments discontinued receipt of coal combustion byproducts and will be subject to final closure on or before April 2018, and two surface impoundments remain active and subject to the final rule. The two landfills remain active and subject to the final rule. Refer to Note 13 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 10 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K for discussion of the impacts on asset retirement obligations as a result of the final rule.

Other

Other laws, regulations and agencies to which the relevant Registrants are subject include, but are not limited to:

- The federal Comprehensive Environmental Response, Compensation and Liability Act and similar state laws may require any current or former owners or operators of a disposal site, as well as transporters or generators of hazardous substances sent to such disposal site, to share in environmental remediation costs.
- The Nuclear Waste Policy Act of 1982, under which the United States Department of Energy is responsible for the selection and development of repositories for, and the permanent disposal of, spent nuclear fuel and high-level radioactive wastes. Refer to Note 13 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 12 of the Notes to Financial Statements of MidAmerican Energy in Item 8 of this Form 10-K for additional information regarding MidAmerican Energy's nuclear decommissioning obligations.
- The federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes establish operational, reclamation and closure standards that must be met during and upon completion of PacifiCorp's mining activities.
- The FERC evaluates hydroelectric systems to ensure environmental impacts are minimized, including the issuance of environmental impact statements for licensed projects both initially and upon relicensing. The FERC monitors the hydroelectric facilities for compliance with the license terms and conditions, which include environmental provisions. Refer to Note 16 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 13 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K for information regarding the relicensing of PacifiCorp's Klamath River hydroelectric system.

The Registrants expect they will be allowed to recover their respective prudently incurred costs to comply with the environmental laws and regulations discussed above. The Registrants' planning efforts take into consideration the complexity of balancing factors such as: (a) pending environmental regulations and requirements to reduce emissions, address waste disposal, ensure water quality and protect wildlife; (b) avoidance of excessive reliance on any one generation technology; (c) costs and trade-offs of various resource options including energy efficiency, demand response programs and renewable generation; (d) state-specific energy policies, resource preferences and economic development efforts; (e) additional transmission investment to reduce power costs and increase efficiency and reliability of the integrated transmission system; and (f) keeping rates affordable. Due to the number of generating units impacted by environmental regulations, deferring installation of compliance-related projects is often not feasible or cost effective and places the Registrants at risk of not having access to necessary capital, material, and labor while attempting to perform major equipment installations in a compressed timeframe concurrent with other utilities across the country. Therefore, the Registrants have established installation schedules with permitting agencies that coordinate compliance timeframes with construction and tie-in of major environmental compliance projects as units are scheduled off-line for planned maintenance outages; these coordinated efforts help reduce costs associated with replacement power and maintain system reliability.

Item 1A. Risk Factors

Each Registrant is subject to numerous risks and uncertainties, including, but not limited to, those described below. Careful consideration of these risks, together with all of the other information included in this Form 10-K and the other public information filed by the relevant Registrant, should be made before making an investment decision. Additional risks and uncertainties not presently known or which each Registrant currently deems immaterial may also impair its business operations. Unless stated otherwise, the risks described below generally relate to each Registrant.

Corporate and Financial Structure Risks

BHE is a holding company and depends on distributions from subsidiaries, including joint ventures, to meet its obligations.

BHE is a holding company with no material assets other than the ownership interests in its subsidiaries and joint ventures, collectively referred to as its subsidiaries. Accordingly, cash flows and the ability to meet BHE's obligations are largely dependent upon the earnings of its subsidiaries and the payment of such earnings to BHE in the form of dividends or other distributions. BHE's subsidiaries are separate and distinct legal entities and have no obligation, contingent or otherwise, to pay amounts due pursuant to BHE's senior debt, junior subordinated debt or its other obligations, or to make funds available, whether by dividends or other payments, for the payment of amounts due pursuant to BHE's senior debt, junior subordinated debt or its other obligations, and do not guarantee the payment of any of its obligations. Distributions from subsidiaries may also be limited by:

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

BHE is substantially leveraged, the terms of its existing senior and junior subordinated debt do not restrict the incurrence of additional debt by BHE or its subsidiaries, and BHE's senior debt is structurally subordinated to the debt of its subsidiaries, and each of such factors could adversely affect BHE's consolidated financial results.

A significant portion of BHE's capital structure is comprised of debt, and BHE expects to incur additional debt in the future to fund items such as, among others, acquisitions, capital investments and the development and construction of new or expanded facilities. As of December 31, 2016, BHE had the following outstanding obligations:

- senior unsecured debt of $7.8 billion;
- junior subordinated debentures of $944 million;
- borrowings under its commercial paper program of $834 million;
- guarantees and letters of credit in respect of subsidiary and equity method investments aggregating $460 million; and
- commitments, subject to satisfaction of certain specified conditions, to provide equity contributions in support of renewable tax equity investments totaling $288 million.

BHE's consolidated subsidiaries also have significant amounts of outstanding debt, which totaled $28.4 billion as of December 31, 2016. These amounts exclude (a) trade debt, (b) preferred stock obligations, (c) letters of credit in respect of subsidiary debt, and (d) BHE's share of the outstanding debt of its own or its subsidiaries' equity method investments.

Given BHE's substantial leverage, it may not have sufficient cash to service its debt, which could limit its ability to finance future acquisitions, develop and construct additional projects, or operate successfully under difficult conditions, including those brought on by adverse national and global economies, unfavorable financial markets or growth conditions where its capital needs may exceed its ability to fund them. BHE's leverage could also impair its credit quality or the credit quality of its subsidiaries, making it more difficult to finance operations or issue future debt on favorable terms, and could result in a downgrade in debt ratings by credit rating agencies.

The terms of BHE's debt do not limit its ability or the ability of its subsidiaries to incur additional debt or issue preferred stock. Accordingly, BHE or its subsidiaries could enter into acquisitions, new financings, refinancings, recapitalizations, capital leases or other highly leveraged transactions that could significantly increase BHE's or its subsidiaries' total amount of outstanding debt. The interest payments needed to service this increased level of debt could adversely affect BHE's consolidated financial results. Many of BHE's subsidiaries' debt agreements contain covenants, or may in the future contain covenants, that restrict or limit, among other things, such subsidiaries' ability to create liens, sell assets, make certain distributions, incur additional debt or miss contractual deadlines or requirements, and BHE's ability to comply with these covenants may be affected by events beyond its control. Further, if an event of default accelerates a repayment obligation and such acceleration results in an event of default under some or all of BHE's other debt, BHE may not have sufficient funds to repay all of the accelerated debt simultaneously, and the other risks described under "Corporate and Financial Structure Risks" may be magnified as well.

Because BHE is a holding company, the claims of its senior debt holders are structurally subordinated with respect to the assets and earnings of its subsidiaries. Therefore, the rights of its creditors to participate in the assets of any subsidiary in the event of a liquidation or reorganization are subject to the prior claims of the subsidiary's creditors and preferred shareholders, if any. In addition, pursuant to separate financing agreements, substantially all of PacifiCorp's electric utility properties, MidAmerican Energy's electric utility properties in the state of Iowa, Nevada Power's and Sierra Pacific's properties in the state of Nevada and AltaLink's transmission properties, the equity interest of MidAmerican Funding's subsidiary, the long-term customer contracts of Kern River and substantially all of the assets of the subsidiaries of BHE Renewables that are direct or indirect owners of generation projects, are directly or indirectly pledged to secure their financings and, therefore, may be unavailable as potential sources of repayment of BHE's debt.

A downgrade in BHE's credit ratings or the credit ratings of its subsidiaries, including the Subsidiary Registrants, could negatively affect BHE's or its subsidiaries' access to capital, increase the cost of borrowing or raise energy transaction credit support requirements.

BHE's senior unsecured debt and its subsidiaries' long-term debt, including the Subsidiary Registrants, are rated by various rating agencies. BHE cannot give assurance that its senior unsecured debt rating or any of its subsidiaries' long-term debt ratings will not be reduced in the future. Although none of the Registrants' outstanding debt has rating-downgrade triggers that would accelerate a repayment obligation, a credit rating downgrade would increase any such Registrant's borrowing costs and commitment fees on its revolving credit agreements and other financing arrangements, perhaps significantly. In addition, such Registrant would likely be required to pay a higher interest rate in future financings, and the potential pool of investors and funding sources would likely decrease. Further, access to the commercial paper market, the principal source of short-term borrowings for each Registrant, could be significantly limited, resulting in higher interest costs.

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

Most of the Registrants' large wholesale customers, suppliers and counterparties require such Registrant to have sufficient creditworthiness in order to enter into transactions, particularly in the wholesale energy markets. If the credit ratings of a Registrant were to decline, especially below investment grade, the relevant Registrant's financing costs and borrowings would likely increase because certain counterparties may require collateral in the form of cash, a letter of credit or some other form of security for existing transactions and as a condition to entering into future transactions with such Registrant. Amounts may be material and may adversely affect such Registrant's liquidity and cash flows.

BHE's majority shareholder, Berkshire Hathaway, could exercise control over BHE in a manner that would benefit Berkshire Hathaway to the detriment of BHE's creditors and BHE could exercise control over the Subsidiary Registrants in a manner that would benefit BHE to the detriment of the Subsidiary Registrants' creditors and PacifiCorp*'s *preferred stockholders.

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

BHE indirectly owns all of the common stock of PacifiCorp, Nevada Power and Sierra Pacific and is the sole member of MidAmerican Funding and, accordingly, indirectly owns all of MidAmerican Energy's common stock. As a result, BHE has control over all decisions requiring shareholder approval, including the election of directors. In circumstances involving a conflict of interest between BHE and the creditors of the Subsidiary Registrants and PacifiCorp's preferred stockholders, BHE could exercise its control in a manner that would benefit BHE to the detriment of the Subsidiary Registrants' creditors and PacifiCorp's preferred stockholders.

Business Risks

Much of BHE's growth has been achieved through acquisitions, and any such acquisition may not be successful.

Much of BHE's growth has been achieved through acquisitions. Future acquisitions may range from buying individual assets to the purchase of entire businesses. BHE will continue to investigate and pursue opportunities for future acquisitions that it believes, but cannot assure you, may increase value and expand or complement existing businesses. BHE may participate in bidding or other negotiations at any time for such acquisition opportunities which may or may not be successful.

Any acquisition entails numerous risks, including, among others:

- the failure to complete the transaction for various reasons, such as the inability to obtain the required regulatory approvals, materially adverse developments in the potential acquiree's business or financial condition or successful intervening offers by third parties;
- the failure of the combined business to realize the expected benefits;
- the risk that federal, state or foreign regulators or courts could require regulatory commitments or other actions in respect of acquired assets, potentially including programs, contributions, investments, divestitures and market mitigation measures;
- the risk of unexpected or unidentified issues not discovered in the diligence process; and
- the need for substantial additional capital and financial investments.

An acquisition could cause an interruption of, or a loss of momentum in, the activities of one or more of BHE's subsidiaries. In addition, the final orders of regulatory authorities approving acquisitions may be subject to appeal by third parties. The diversion of BHE management's attention and any delays or difficulties encountered in connection with the approval and integration of the acquired operations could adversely affect BHE's combined businesses and financial results and could impair its ability to realize the anticipated benefits of the acquisition.

BHE cannot assure you that future acquisitions, if any, or any integration efforts will be successful, or that BHE's ability to repay its obligations will not be adversely affected by any future acquisitions.

The Registrants are subject to operating uncertainties and events beyond each respective Registrant's control that impact the costs to operate, maintain, repair and replace utility and interstate natural gas pipeline systems, which could adversely affect each respective Registrant's consolidated financial results.

The operation of complex utility systems or interstate natural gas pipeline and storage systems that are spread over large geographic areas involves many operating uncertainties and events beyond each respective Registrant's control. These potential events include the breakdown or failure of the Registrants' thermal, nuclear, hydroelectric, solar, wind and other electricity generating facilities and related equipment, compressors, pipelines, transmission and distribution lines or other equipment or processes, which could lead to catastrophic events; unscheduled outages; strikes, lockouts or other labor-related actions; shortages of qualified labor; transmission and distribution system constraints; failure to obtain, renew or maintain rights-of-way, easements and leases on United States federal, Native American, First Nations or tribal lands; terrorist activities or military or other actions, including cyber attacks; fuel shortages or interruptions; unavailability of critical equipment, materials and supplies; low water flows and other weather-related impacts; performance below expected levels of output, capacity or efficiency; operator error; third party excavation errors; unexpected degradation of pipeline systems; design, construction or manufacturing defects; and catastrophic events such as severe storms, floods, fires, earthquakes, explosions, landslides, wars, terrorism, embargoes and mining accidents. A catastrophic event might result in injury or loss of life, extensive property damage or environmental or natural resource damages. For example, in the event of an uncontrolled release of water at one of PacifiCorp's high hazard potential hydroelectric dams, it is probable that loss of human life, disruption of lifeline facilities and property damage could occur in the downstream population and civil or other penalties could be imposed by the FERC. Any of these events or other operational events could significantly reduce or eliminate the relevant Registrant's revenue or significantly increase its expenses, thereby reducing the availability of distributions to BHE. For example, if the relevant Registrant cannot operate its electricity or natural gas facilities at full capacity due to damage caused by a catastrophic event, its revenue could decrease and its expenses could increase due to the need to obtain energy from more expensive sources. Further, the Registrants self-insure many risks, and current and future insurance coverage may not be sufficient to replace lost revenue or cover repair and replacement costs. The scope, cost and availability of each Registrant's insurance coverage may change, including the portion that is self-insured. Any reduction of each Registrant's revenue or increase in its expenses resulting from the risks described above, could adversely affect the relevant Registrant's consolidated financial results.

Each Registrant is subject to extensive federal, state, local and foreign legislation and regulation, including numerous environmental, health, safety, reliability and other laws and regulations that affect its operations and costs. These laws and regulations are complex, dynamic and subject to new interpretations or change. In addition, new laws and regulations, including initiatives regarding deregulation and restructuring of the utility industry, are continually being proposed and enacted that impose new or revised requirements or standards on each Registrant.

Each Registrant is required to comply with numerous federal, state, local and foreign laws and regulations as described in "General Regulation" and "Environmental Laws and Regulations" in Item 1 of this Form 10-K that have broad application to each Registrant and limits the respective Registrant's ability to independently make and implement management decisions regarding, among other items, acquiring businesses; constructing, acquiring or disposing of operating assets; operating and maintaining generating facilities and transmission and distribution system assets; complying with pipeline safety and integrity and environmental requirements; setting rates charged to customers; establishing capital structures and issuing debt or equity securities; transacting between subsidiaries and affiliates; and paying dividends or similar distributions. These laws and regulations are followed in developing the Registrants' safety and compliance programs and procedures and are implemented and enforced by federal, state and local regulatory agencies, such as, among others, the Occupational Safety and Health Administration, the FERC, the EPA, the DOT, the NRC, the Federal Mine Safety and Health Administration and various state regulatory commissions in the United States, and foreign regulatory agencies, such as GEMA, which discharges certain of its powers through its staff within Ofgem, in Great Britain and the AUC in Alberta, Canada.

Compliance with applicable laws and regulations generally requires each Registrant to obtain and comply with a wide variety of licenses, permits, inspections, audits and other approvals. Further, compliance with laws and regulations can require significant capital and operating expenditures, including expenditures for new equipment, inspection, cleanup costs, removal and remediation costs, damages arising out of contaminated properties and refunds, fines, penalties and injunctive measures affecting operating assets for failure to comply with environmental regulations. Compliance activities pursuant to existing or new laws and regulations could be prohibitively expensive or otherwise uneconomical. As a result, each Registrant could be required to shut down some facilities or materially alter its operations. Further, each Registrant may not be able to obtain or maintain all required environmental or other regulatory approvals and permits for its operating assets or development projects. Delays in, or active opposition by third parties to, obtaining any required environmental or regulatory authorizations or failure to comply with the terms and conditions of the authorizations may increase costs or prevent or delay each Registrant from operating its facilities, developing or favorably locating new facilities or expanding existing facilities. If any Registrant fails to comply with any environmental or other regulatory requirements, such Registrant may be subject to penalties and fines or other sanctions, including changes to the way its electricity generating facilities are operated that may adversely impact generation or how the Pipeline Companies are permitted to operate their systems that may adversely impact throughput. The costs of complying with laws and regulations could adversely affect each Registrant's consolidated financial results. Not being able to operate existing facilities or develop new generating facilities to meet customer electricity needs could require such Registrant to increase its purchases of electricity on the wholesale market, which could increase market and price risks and adversely affect such Registrant's consolidated financial results.

Existing laws and regulations, while comprehensive, are subject to changes and revisions from ongoing policy initiatives by legislators and regulators and to interpretations that may ultimately be resolved by the courts. For example, changes in laws and regulations could result in, but are not limited to, increased competition within each Registrant's service territories, such as the Nevada energy choice initiative; new environmental requirements, including the implementation of or changes to the Clean Power Plan, RPS and GHG emissions reduction goals; the issuance of new or stricter air quality standards; the implementation of energy efficiency mandates; the issuance of regulations governing the management and disposal of coal combustion byproducts; changes in forecasting requirements; changes to each Registrant's service territories as a result of condemnation or takeover by municipalities or other governmental entities, particularly where it lacks the exclusive right to serve its customers; the inability of each Registrant to recover its costs on a timely basis, if at all; new pipeline safety requirements; or a negative impact on each Registrant's current transportation and cost recovery arrangements. In addition to changes in existing legislation and regulation, new laws and regulations are likely to be enacted from time to time that impose additional or new requirements or standards on each Registrant.

Implementing actions required under, and otherwise complying with, new federal and state laws and regulations and changes in existing ones are among the most challenging aspects of managing utility operations. The Registrants cannot accurately predict the type or scope of future laws and regulations that may be enacted, changes in existing ones or new interpretations by agency orders or court decisions nor can each Registrant determine their impact on it at this time; however, any one of these could adversely affect each Registrant's consolidated financial results through higher capital expenditures and operating costs, and early closure of generating facilities or restrict or otherwise cause an adverse change in how each Registrant operates its business. To the extent that each Registrant is not allowed by its regulators to recover or cannot otherwise recover the costs to comply with new laws and regulations or changes in existing ones, the costs of complying with such additional requirements could have a material adverse effect on the relevant Registrant's consolidated financial results. Additionally, even if such costs are recoverable in rates, if they are substantial and result in rates increasing to levels that substantially reduce customer demand, this could have a material adverse effect on the relevant Registrant's consolidated financial results.

Recovery of costs and certain activities by each Registrant is subject to regulatory review and approval, and the inability to recover costs or undertake certain activities may adversely affect each Registrant's consolidated financial results.

State Regulatory Rate Review Proceedings

The Utilities establish rates for their regulated retail service through state regulatory proceedings. These proceedings typically involve multiple parties, including government bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns but generally have the common objective of limiting rate increases while also requiring the Utilities to ensure system reliability. Decisions are subject to judicial appeal, potentially leading to further uncertainty associated with the approval proceedings.

States set retail rates based in part upon the state regulatory commission's acceptance of an allocated share of total utility costs. When states adopt different methods to calculate interjurisdictional cost allocations, some costs may not be incorporated into rates of any state or other jurisdiction. Ratemaking is also generally done on the basis of estimates of normalized costs, so if a given year's realized costs are higher than normalized costs, rates may not be sufficient to cover those costs. In some cases, actual costs are lower than the normalized or estimated costs recovered through rates and from time-to-time may result in a state regulator requiring refunds to customers. Each state regulatory commission generally sets rates based on a test year established in accordance with that commission's policies. The test year data adopted by each state regulatory commission may create a lag between the incurrence of a cost and its recovery in rates. Each state regulatory commission also decides the allowed levels of expense, investment and capital structure that it deems are just and reasonable in providing the service and may disallow recovery in rates for any costs that it believes do not meet such standard. Additionally, each state regulatory commission establishes the allowed rate of return the Utilities will be given an opportunity to earn on their sources of capital. While rate regulation is premised on providing a fair opportunity to earn a reasonable rate of return on invested capital, the state regulatory commissions do not guarantee that each Registrant will be able to realize the allowed rate of return.

Energy cost increases above the level assumed in establishing base rates may be subject to customer sharing. Any significant increase in fuel costs for electricity generation or purchased electricity costs could have a negative impact on the Utilities, despite efforts to minimize this impact through the use of hedging contracts and sharing mechanisms or through future general regulatory rate reviews. Any of these consequences could adversely affect each Registrant's consolidated financial results.

FERC Jurisdiction

The FERC authorizes cost-based rates associated with transmission services provided by the Utilities' transmission facilities. Under the Federal Power Act, the Utilities, or MISO as it relates to MidAmerican Energy, may voluntarily file, or may be obligated to file, for changes, including general rate changes, to their system-wide transmission service rates. General rate changes implemented may be subject to refund. The FERC also has responsibility for approving both cost- and market-based rates under which the Utilities sell electricity at wholesale, has jurisdiction over most of PacifiCorp's hydroelectric generating facilities and has broad jurisdiction over energy markets. The FERC may impose price limitations, bidding rules and other mechanisms to address some of the volatility of these markets or could revoke or restrict the ability of the Utilities to sell electricity at market-based rates, which could adversely affect each Registrant's consolidated financial results. The FERC also maintains rules concerning standards of conduct, affiliate restrictions, interlocking directorates and cross-subsidization. As a transmission owning member of MISO, MidAmerican Energy is also subject to MISO-directed modifications of market rules, which are subject to FERC approval and operational procedures. As participants in EIM, PacifiCorp, Nevada Power and Sierra Pacific are also subject to applicable California ISO rules, which are subject to FERC approval and operational procedures. The FERC may also impose substantial civil penalties for any non-compliance with the Federal Power Act and the FERC's rules and orders.

The NERC has standards in place to ensure the reliability of the electric generation system and transmission grid. The Utilities are subject to the NERC's regulations and periodic audits to ensure compliance with those regulations. The NERC may carry out enforcement actions for non-compliance and administer significant financial penalties, subject to the FERC's review.

The FERC has jurisdiction over, among other things, the construction, abandonment, modification and operation of natural gas pipelines and related facilities used in the transportation, storage and sale of natural gas in interstate commerce, including all rates, charges and terms and conditions of service. The FERC also has market transparency authority and has adopted additional reporting and internet posting requirements for natural gas pipelines and buyers and sellers of natural gas.

Rates for the interstate natural gas transmission and storage operations at the Pipeline Companies, which include reservation, commodity, surcharges, fuel and gas lost and unaccounted for charges, are authorized by the FERC. In accordance with the FERC's rate-making principles, the Pipeline Companies' current maximum tariff rates are designed to recover prudently incurred costs included in their pipeline system's regulatory cost of service that are associated with the construction, operation and maintenance of their pipeline system and to afford the Pipeline Companies an opportunity to earn a reasonable rate of return. Nevertheless, the rates the FERC authorizes the Pipeline Companies to charge their customers may not be sufficient to recover the costs incurred to provide services in any given period. Moreover, from time to time, the FERC may change, alter or refine its policies or methodologies for establishing pipeline rates and terms and conditions of service. In addition, the FERC has the authority under Section 5 of the Natural Gas Act of 1938 ("NGA") to investigate whether a pipeline may be earning more than its allowed rate of return and, when appropriate, to institute proceedings against such pipeline to prospectively reduce rates. Any such proceedings, if instituted, could result in significantly adverse rate decreases.

Under FERC policy, interstate pipelines and their customers may execute contracts at negotiated rates, which may be above or below the maximum tariff rate for that service or the pipeline may agree to provide a discounted rate, which would be a rate between the maximum and minimum tariff rates. In a rate proceeding, rates in these contracts are generally not subject to adjustment. It is possible that the cost to perform services under negotiated or discounted rate contracts will exceed the cost used in the determination of the negotiated or discounted rates, which could result either in losses or lower rates of return for providing such services. Under certain circumstances, FERC policy allows interstate natural gas pipelines to design new maximum tariff rates to recover such costs in regulatory rate reviews. However, with respect to discounts granted to affiliates, the interstate natural gas pipeline must demonstrate that the discounted rate was necessary in order to meet competition.

GEMA Jurisdiction

The Northern Powergrid Distribution Companies, as Distribution Network Operators ("DNOs") and holders of electricity distribution licenses, are subject to regulation by GEMA. Most of the revenue of a DNO is controlled by a distribution price control formula set out in the electricity distribution license. The price control formula does not directly constrain profits from year to year, but is a control on revenue that operates independently of a significant portion of the DNO's actual costs. A resetting of the formula does not require the consent of the DNO, but if a licensee disagrees with a change to its license it can appeal the matter to the United Kingdom's Competition and Markets Authority. GEMA is able to impose financial penalties on DNOs that contravene any of their electricity distribution license duties or certain of their duties under British law, or fail to achieve satisfactory performance of individual standards prescribed by GEMA. Any penalty imposed must be reasonable and may not exceed 10% of the DNO's revenue. During the term of any price control, additional costs have a direct impact on the financial results of the Northern Powergrid Distribution Companies.

AUC Jurisdiction

The AUC is an independent, quasi-judicial agency established by the province of Alberta, Canada, which is responsible for, among other things, approving the tariffs of transmission facility owners, including ALP, and distribution utilities, acquisitions of such transmission facility owners or utilities, and construction and operation of new transmission projects in Alberta. The AUC also investigates and rules on regulated rate disputes and system access problems.

The AUC regulates and oversees Alberta's electricity transmission sector with broad authority that may impact many of ALP's activities, including its tariffs, rates, construction, operations and financing. The AUC has various core functions in regulating the Alberta electricity transmission sector, including the following:

- regulating and adjudicating issues related to the operation of electric utilities within Alberta;
- processing and approving general tariff applications relating to revenue requirements and rates of return including deemed capital structure for regulated utilities while ensuring that utility rates are just and reasonable and approval of the transmission tariff rates of regulated transmission providers by the AESO, which is the independent transmission system operator in Alberta that controls the operation of AltaLink's transmission system;
- approving the need for new electricity transmission facilities and permits to build and licenses to operate electricity transmission facilities;
- reviewing operations and accounts from electric utilities and conducting on-site inspections to ensure compliance with industry regulation and standards;
- adjudicating enforcement issues including the imposition of administrative penalties that arise when market participants violate the rules of the AESO; and
- collecting, storing, analyzing, appraising and disseminating information to effectively fulfill its duties as an industry regulator.

In addition, AUC approval is required in connection with new energy and regulated utility initiatives in Alberta, amendments to existing approvals and financing proposals by designated utilities.

The AESO determines the need and plans for the expansion and enhancement of a congestion free transmission system in Alberta in accordance with applicable law and reliability standards. The AESO's responsibilities include long-term transmission planning and management, including assessing and planning for the current and future transmission system capacity needs of AESO market participants. When AESO determines an expansion or enhancement of the transmission system is needed, with limited exceptions, it submits an application to the AUC for approval of the proposed expansion or enhancement. The AESO then determines which transmission provider should submit an application to the AUC for a permit and license to construct and operate the designated transmission facilities. Generally the transmission provider operating in the geographic area where the transmission facilities expansion or enhancement is to be located is selected by the AESO to build, own and operate the transmission facilities. In addition, Alberta law provides that transmission projects may be subject to a competitive process open to qualifying bidders. In either case, there can be no assurance that any jurisdictional market participant that BHE may own, including AltaLink, will be selected by the AESO to build, own and operate transmission facilities, even if BHE's market participant operates in the relevant geographic area, or that BHE's market participant will be successful in any such competitive process in which it may participate.

Each Registrant is actively pursuing, developing and constructing new or expanded facilities, the completion and expected costs of which are subject to significant risk, and each Registrant has significant funding needs related to its planned capital expenditures.

Each Registrant actively pursues, develops and constructs new or expanded facilities. Each Registrant expects to incur significant annual capital expenditures over the next several years. Such expenditures may include construction and other costs for new electricity generating facilities, electric transmission or distribution projects, environmental control and compliance systems, natural gas storage facilities, new or expanded pipeline systems, and continued maintenance and upgrades of existing assets.

Development and construction of major facilities are subject to substantial risks, including fluctuations in the price and availability of commodities, manufactured goods, equipment, labor, siting and permitting and changes in environmental and operational compliance matters, load forecasts and other items over a multi-year construction period, as well as counterparty risk and the economic viability of the Registrants' suppliers, customers and contractors. Certain of the Registrants' construction projects are substantially dependent upon a single supplier or contractor and replacement of such supplier or contractor may be difficult and cannot be assured. These risks may result in the inability to timely complete a project or higher than expected costs to complete an asset and place it in-service and, in extreme cases, the loss of the power purchase agreements or other long-term off-take contracts underlying such projects. Such costs may not be recoverable in the regulated rates or market or contract prices each Registrant is able to charge its customers. Delays in construction of renewable projects may result in delayed in-service dates which may result in the loss of anticipated revenue or income tax benefits. It is also possible that additional generation needs may be obtained through power purchase agreements, which could increase long-term purchase obligations and force reliance on the operating performance of a third party. The inability to successfully and timely complete a project, avoid unexpected costs or recover any such costs could adversely affect such Registrant's consolidated financial results.

Furthermore, each Registrant depends upon both internal and external sources of liquidity to provide working capital and to fund capital requirements. If BHE does not provide needed funding to its subsidiaries and the subsidiaries are unable to obtain funding from external sources, they may need to postpone or cancel planned capital expenditures.

A significant sustained decrease in demand for electricity or natural gas in the markets served by each Registrant would decrease its operating revenue, could impact its planned capital expenditures and could adversely affect its consolidated financial results.

A significant sustained decrease in demand for electricity or natural gas in the markets served by each Registrant would decrease its operating revenue, could impact its planned capital expenditures and could adversely affect its consolidated financial results. Factors that could lead to a decrease in market demand include, among others:

- a depression, recession or other adverse economic condition that results in a lower level of economic activity or reduced spending by consumers on electricity or natural gas;
- an increase in the market price of electricity or natural gas or a decrease in the price of other competing forms of energy;
- shifts in competitively priced natural gas supply sources away from the sources connected to the Pipeline Companies' systems, including shale gas sources;
- efforts by customers, legislators and regulators to reduce the consumption of electricity generated or distributed by each Registrant through various existing laws and regulations, as well as, deregulation, conservation, energy efficiency and private generation measures and programs;
- laws mandating or encouraging renewable energy sources, which may decrease the demand for electricity and natural gas or change the market prices of these commodities;
- higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of natural gas or other fuel sources for electricity generation or that limit the use of natural gas or the generation of electricity from fossil fuels;
- a shift to more energy-efficient or alternative fuel machinery or an improvement in fuel economy, whether as a result of technological advances by manufacturers, legislation mandating higher fuel economy or lower emissions, price differentials, incentives or otherwise;
- a reduction in the state or federal subsidies or tax incentives that are provided to agricultural, industrial or other customers, or a significant sustained change in prices for commodities such as ethanol or corn for ethanol manufacturers; and
- sustained mild weather that reduces heating or cooling needs.

Each Registrant's operating results may fluctuate on a seasonal and quarterly basis and may be adversely affected by weather.

In most parts of the United States and other markets in which each Registrant operates, demand for electricity peaks during the summer months when irrigation and cooling needs are higher. Market prices for electricity also generally peak at that time. In other areas, demand for electricity peaks during the winter when heating needs are higher. In addition, demand for natural gas and other fuels generally peaks during the winter. This is especially true in MidAmerican Energy's and Sierra Pacific's retail natural gas businesses. Further, extreme weather conditions, such as heat waves, winter storms or floods could cause these seasonal fluctuations to be more pronounced. Periods of low rainfall or snowpack may negatively impact electricity generation at PacifiCorp's hydroelectric generating facilities, which may result in greater purchases of electricity from the wholesale market or from other sources at market prices. Additionally, PacifiCorp and MidAmerican Energy have added substantial wind-powered generating capacity, and BHE's unregulated subsidiaries are adding solar and wind-powered generating capacity, each of which is also a climate-dependent resource.

As a result, the overall financial results of each Registrant may fluctuate substantially on a seasonal and quarterly basis. Each Registrant has historically provided less service, and consequently earned less income, when weather conditions are mild. Unusually mild weather in the future may adversely affect each Registrant's consolidated financial results through lower revenue or margins. Conversely, unusually extreme weather conditions could increase each Registrant's costs to provide services and could adversely affect its consolidated financial results. The extent of fluctuation in each Registrant's consolidated financial results may change depending on a number of factors related to its regulatory environment and contractual agreements, including its ability to recover energy costs, the existence of revenue sharing provisions as it relates to MidAmerican Energy, and terms of its wholesale sale contracts.

Each Registrant is subject to market risk associated with the wholesale energy markets, which could adversely affect its consolidated financial results.

In general, each Registrant's primary market risk is adverse fluctuations in the market price of wholesale electricity and fuel, including natural gas, coal and fuel oil, which is compounded by volumetric changes affecting the availability of or demand for electricity and fuel. The market price of wholesale electricity may be influenced by several factors, such as the adequacy or type of generating capacity, scheduled and unscheduled outages of generating facilities, prices and availability of fuel sources for generation, disruptions or constraints to transmission and distribution facilities, weather conditions, demand for electricity, economic growth and changes in technology. Volumetric changes are caused by fluctuations in generation or changes in customer needs that can be due to the weather, electricity and fuel prices, the economy, regulations or customer behavior. For example, the Utilities purchase electricity and fuel in the open market as part of their normal operating businesses. If market prices rise, especially in a time when larger than expected volumes must be purchased at market prices, the Utilities may incur significantly greater expense than anticipated. Likewise, if electricity market prices decline in a period when the Utilities are a net seller of electricity in the wholesale market, the Utilities could earn less revenue. Although the Utilities have energy cost adjustment mechanisms, the risks associated with changes in market prices may not be fully mitigated due to customer sharing bands as it relates to PacifiCorp and other factors.

Potential terrorist activities and the impact of military or other actions, could adversely affect each Registrant's consolidated financial results.

The ongoing threat of terrorism and the impact of military or other actions by nations or politically, ethnically or religiously motivated organizations regionally or globally may create increased political, economic, social and financial market instability, which could subject each Registrant's operations to increased risks. Additionally, the United States government has issued warnings that energy assets, specifically pipeline, nuclear generation, transmission and other electric utility infrastructure, are potential targets for terrorist attacks. Political, economic, social or financial market instability or damage to or interference with the operating assets of the Registrants, customers or suppliers may result in business interruptions, lost revenue, higher commodity prices, disruption in fuel supplies, lower energy consumption and unstable markets, particularly with respect to electricity and natural gas, and increased security, repair or other costs, any of which may materially adversely affect each Registrant in ways that cannot be predicted at this time. Any of these risks could materially affect its consolidated financial results. Furthermore, instability in the financial markets as a result of terrorism or war could also materially adversely affect each Registrant's ability to raise capital.

Physical or cyber attacks, both threatened and actual, could impact each Registrant's operations and could adversely affect its consolidated financial results.

Each Registrant relies on information technology in virtually all aspects of its business. A significant disruption or failure of its information technology systems by physical or cyber attack could result in service interruptions, safety failures, security violations, regulatory compliance failures, an inability to protect corporate information assets against intruders, and other operational difficulties. Attacks perpetrated against each Registrant's information systems could result in loss of assets and critical information and expose it to remediation costs and reputational damage.

Although the Registrants have taken steps intended to mitigate these risks, including business continuity planning, disaster recovery planning and business impact analysis, a significant disruption or cyber intrusion could lead to misappropriation of assets or data corruption and could adversely affect each Registrant's results of operations, financial condition or liquidity. Additionally, if each Registrant is unable to acquire or implement new technology, it may suffer a competitive disadvantage, which could also have an adverse effect on its results of operations, financial condition or liquidity. Cyber attacks could further adversely affect each Registrant's ability to operate facilities, information technology and business systems, or compromise confidential customer and employee information. In addition, physical or cyber attacks against key suppliers or service providers could have a similar effect on each Registrant.

Certain Registrants are subject to the unique risks associated with nuclear generation.

The ownership and operation of nuclear power plants, such as MidAmerican Energy's 25% ownership interest in Quad Cities Station, involves certain risks. These risks include, among other items, mechanical or structural problems, inadequacy or lapses in maintenance protocols, the impairment of reactor operation and safety systems due to human error, the costs of storage, handling and disposal of nuclear materials, compliance with and changes in regulation of nuclear power plants, limitations on the amounts and types of insurance coverage commercially available, and uncertainties with respect to the technological and financial aspects of decommissioning nuclear facilities at the end of their useful lives. Additionally, Exelon Generation, the 75% owner and operator of the facility, may respond to the occurrence of any of these or other risks in a manner that negatively impacts MidAmerican Energy, including closure of Quad Cities Station prior to the expiration of its operating license. The prolonged unavailability, or early closure, of Quad Cities Station due to operational or economic factors could have a materially adverse effect on the relevant Registrant's financial results, particularly when the cost to produce power at the plant is significantly less than market wholesale prices. The following are among the more significant of these risks:

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

  In addition, issues relating to the disposal of nuclear waste material, including the availability, unavailability and expense of a permanent repository for spent nuclear fuel could adversely impact operations as well as the cost and ability to decommission nuclear power plants, including Quad Cities Station, in the future.

- *Regulatory Risk* - The NRC may modify, suspend or revoke licenses and impose civil penalties for failure to comply with applicable Atomic Energy Act regulations or the terms of the licenses of nuclear facilities. Unless extended, the NRC operating licenses for Quad Cities Station will expire in 2032. Changes in regulations by the NRC could require a substantial increase in capital expenditures or result in increased operating or decommissioning costs.
- *Nuclear Accident and Catastrophic Risks* - Accidents and other unforeseen catastrophic events have occurred at nuclear facilities other than Quad Cities Station, both in the United States and elsewhere, such as at the Fukushima Daiichi nuclear power plant in Japan as a result of the earthquake and tsunami in March 2011. The consequences of an accident or catastrophic event can be severe and include loss of life and property damage. Any resulting liability from a nuclear accident or catastrophic event could exceed the relevant Registrant's resources, including insurance coverage.

Certain of BHE's subsidiaries are subject to the risk that customers will not renew their contracts or that BHE's subsidiaries will be unable to obtain new customers for expanded capacity, each of which could adversely affect its consolidated financial results.

If BHE's subsidiaries are unable to renew, remarket, or find replacements for their customer agreements on favorable terms, BHE's subsidiaries' sales volumes and operating revenue would be exposed to reduction and increased volatility. For example, without the benefit of long-term transportation agreements, BHE cannot assure that the Pipeline Companies will be able to transport natural gas at efficient capacity levels. Substantially all of the Pipeline Companies' revenues are generated under transportation and storage contracts that periodically must be renegotiated and extended or replaced, and the Pipeline Companies are dependent upon relatively few customers for a substantial portion of their revenue. Similarly, without long-term power purchase agreements, BHE cannot assure that its unregulated power generators will be able to operate profitably. Failure to maintain existing long-term agreements or secure new long-term agreements, or being required to discount rates significantly upon renewal or replacement, could adversely affect BHE's consolidated financial results. The replacement of any existing long-term agreements depends on market conditions and other factors that may be beyond BHE's subsidiaries' control.

Each Registrant is subject to counterparty risk, which could adversely affect its consolidated financial results.

Each Registrant is subject to counterparty credit risk related to contractual payment obligations with wholesale suppliers and customers. Adverse economic conditions or other events affecting counterparties with whom each Registrant conducts business could impair the ability of these counterparties to meet their payment obligations. Each Registrant depends on these counterparties to remit payments on a timely basis. Each Registrant continues to monitor the creditworthiness of its wholesale suppliers and customers in an attempt to reduce the impact of any potential counterparty default. If strategies used to minimize these risk exposures are ineffective or if any Registrant's wholesale suppliers' or customers' financial condition deteriorates or they otherwise become unable to pay, it could have a significant adverse impact on each Registrant's liquidity and its consolidated financial results.

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

Each Registrant relies on wholesale customers to take delivery of the energy they have committed to purchase. Failure of customers to take delivery may require the relevant Registrant to find other customers to take the energy at lower prices than the original customers committed to pay. If each Registrant's wholesale customers are unable to fulfill their obligations, there may be a significant adverse impact on its consolidated financial results.

The Northern Powergrid Distribution Companies' customers are concentrated in a small number of electricity supply businesses with RWE Npower PLC accounting for approximately 22% of distribution revenue in 2016. AltaLink's primary source of operating revenue is the AESO. Generally, a single customer purchases the energy from BHE's independent power projects in the United States and the Philippines pursuant to long-term power purchase agreements. Any material performance failure by the counterparties in these arrangements could have a significant adverse impact on BHE's consolidated financial results.

BHE owns investments and projects in foreign countries that are exposed to risks related to fluctuations in foreign currency exchange rates and increased economic, regulatory and political risks.

BHE's business operations and investments outside the United States increase its risk related to fluctuations in foreign currency exchange rates, primarily the British pound and the Canadian dollar. BHE's principal reporting currency is the United States dollar, and the value of the assets and liabilities, earnings, cash flows and potential distributions from its foreign operations changes with the fluctuations of the currency in which they transact. BHE indirectly owns a hydroelectric power plant in the Philippines and may acquire significant energy-related investments and projects outside of the United States. BHE may selectively reduce some foreign currency exchange rate risk by, among other things, requiring contracted amounts be settled in, or indexed to, United States dollars or a currency freely convertible into United States dollars, or hedging through foreign currency derivatives. These efforts, however, may not be effective and could negatively affect BHE's consolidated financial results.

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

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

Costs of providing each Registrant's defined benefit pension and other postretirement benefit plans and costs associated with the joint trustee plan to which PacifiCorp contributes depend upon a number of factors, including the rates of return on plan assets, the level and nature of benefits provided, discount rates, mortality assumptions, the interest rates used to measure required minimum funding levels, the funded status of the plans, changes in benefit design, tax deductibility and funding limits, changes in laws and government regulation and each Registrant's required or voluntary contributions made to the plans. Certain of the Registrant's pension and other postretirement benefit plans are in underfunded positions. Even if sustained growth in the investments over future periods increases the value of these plans' assets, each Registrant will likely be required to make cash contributions to fund these plans in the future. Additionally, each Registrant's plans have investments in domestic and foreign equity and debt securities and other investments that are subject to loss. Losses from investments could add to the volatility, size and timing of future contributions.

Furthermore, the funded status of the UMWA 1974 Pension Plan multiemployer plan to which PacifiCorp's subsidiary previously contributed is considered critical and declining. PacifiCorp's subsidiary involuntarily withdrew from the UMWA 1974 Pension Plan in June 2015 when the UMWA employees ceased performing work for the subsidiary. PacifiCorp has recorded its best estimate of the withdrawal obligation. If participating employers withdraw from a multiemployer plan, the unfunded obligations of the plan may be borne by the remaining participating employers, including any employers that withdrew during the three years prior to a mass withdrawal.

In addition, MidAmerican Energy is required to fund over time the projected costs of decommissioning Quad Cities Station, a nuclear power plant, and Bridger Coal Company, a joint venture of PacifiCorp's subsidiary, Pacific Minerals, Inc., is required to fund projected mine reclamation costs. Funds that MidAmerican Energy has invested in a nuclear decommissioning trust and PacifiCorp has invested in a mine reclamation trust are invested in debt and equity securities and poor performance of these investments will reduce the amount of funds available for their intended purpose, which could require MidAmerican Energy or PacifiCorp to make additional cash contributions. Such cash funding obligations, which are also impacted by the other factors described above, could have a material impact on MidAmerican Energy's or PacifiCorp's liquidity by reducing their available cash.

Inflation and changes in commodity prices and fuel transportation costs may adversely affect each Registrant's consolidated financial results.

Inflation and increases in commodity prices and fuel transportation costs may affect each Registrant by increasing both operating and capital costs. As a result of existing rate agreements, contractual arrangements or competitive price pressures, each Registrant may not be able to pass the costs of inflation on to its customers. If each Registrant is unable to manage cost increases or pass them on to its customers, its consolidated financial results could be adversely affected.

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

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

- rising interest rates or unemployment rates, including a sustained high unemployment rate in the United States;
- periods of economic slowdown or recession in the markets served;
- decreasing home affordability;
- lack of available mortgage credit for potential homebuyers, such as the reduced availability of credit, which may continue into future periods;
- inadequate home inventory levels;
- nontraditional sources of new competition; and
- changes in applicable tax law.

Disruptions in the financial markets could affect each Registrant's ability to obtain debt financing or to draw upon or renew existing credit facilities and have other adverse effects on each Registrant.

Disruptions in the financial markets could affect each Registrant's ability to obtain debt financing or to draw upon or renew existing credit facilities and have other adverse effects on each Registrant. Significant dislocations and liquidity disruptions in the United States, Great Britain, Canada and global credit markets, such as those that occurred in 2008 and 2009, may materially impact liquidity in the bank and debt capital markets, making financing terms less attractive for borrowers that are able to find financing and, in other cases, may cause certain types of debt financing, or any financing, to be unavailable. Additionally, economic uncertainty in the United States or globally may adversely affect the United States' credit markets and could negatively impact each Registrant's ability to access funds on favorable terms or at all. If each Registrant is unable to access the bank and debt markets to meet liquidity and capital expenditure needs, it may adversely affect the timing and amount of its capital expenditures, acquisition financing and its consolidated financial results.

Each Registrant is involved in a variety of legal proceedings, the outcomes of which are uncertain and could adversely affect its consolidated financial results.

Each Registrant is, and in the future may become, a party to a variety of legal proceedings. Litigation is subject to many uncertainties, and the Registrants cannot predict the outcome of individual matters with certainty. It is possible that the final resolution of some of the matters in which each Registrant is involved could result in additional material payments substantially in excess of established reserves or in terms that could require each Registrant to change business practices and procedures or divest ownership of assets. Further, litigation could result in the imposition of financial penalties or injunctions and adverse regulatory consequences, any of which could limit each Registrant's ability to take certain desired actions or the denial of needed permits, licenses or regulatory authority to conduct its business, including the siting or permitting of facilities. Any of these outcomes could have a material adverse effect on such Registrant's consolidated financial results.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

Each Registrant's energy properties consist of the physical assets necessary to support its applicable electricity and natural gas businesses. Properties of the relevant Registrant's electricity businesses include electric generation, transmission and distribution facilities, as well as coal mining assets that support certain of PacifiCorp's electric generating facilities. Properties of the relevant Registrant's natural gas businesses include natural gas distribution facilities, interstate pipelines, storage facilities, compressor stations and meter stations. The transmission and distribution assets are primarily within each Registrant's service territories. In addition to these physical assets, the Registrants have rights-of-way, mineral rights and water rights that enable each Registrant to utilize its facilities. It is the opinion of each Registrant's management that the principal depreciable properties owned by it are in good operating condition and are well maintained. Pursuant to separate financing agreements, substantially all of PacifiCorp's electric utility properties, MidAmerican Energy's electric utility properties in the state of Iowa, Nevada Power's and Sierra Pacific's properties in the state of Nevada, AltaLink's transmission properties and substantially all of the assets of the subsidiaries of BHE Renewables are pledged or encumbered to support or otherwise provide the security for the related subsidiary debt. For additional information regarding each Registrant's energy properties, refer to Item 1 of this Form 10-K and Notes 4, 5 and 21 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K, Notes 3 and 4 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K, Notes 4 and 5 of the Notes to Financial Statements of MidAmerican Energy in Item 8 of this Form 10-K, Notes 3 and 4 of the Notes to Consolidated Financial Statements of Nevada Power in Item 8 of this Form 10-K and Notes 3 and 4 of the Notes to Consolidated Financial Statements of Sierra Pacific in Item 8 of this Form 10-K.

The following table summarizes Berkshire Hathaway Energy's electric generating facilities that are in operation as of December 31, 2016:

Energy Source	Entity	Location by Significance	Facility Net Capacity (MW)	Net Owned Capacity (MW)
Natural gas	PacifiCorp, MidAmerican Energy, NV Energy and BHE Renewables	Nevada, Utah, Iowa, Illinois, Washington, Oregon, Texas, New York and Arizona	10,917	10,508
Coal	PacifiCorp, MidAmerican Energy and NV Energy	Wyoming, Iowa, Utah, Arizona, Nevada, Colorado and Montana	16,485	9,412
Wind	PacifiCorp, MidAmerican Energy and BHE Renewables	Iowa, Wyoming, Nebraska, Washington, California, Texas, Oregon, Illinois and Kansas	6,199	6,190
Solar	BHE Renewables and NV Energy	California, Arizona, Minnesota and Nevada	1,464	1,316
Hydroelectric	PacifiCorp, MidAmerican Energy and BHE Renewables	Washington, Oregon, The Philippines, Idaho, California, Utah, Hawaii, Montana, Illinois and Wyoming	1,297	1,275
Nuclear	MidAmerican Energy	Illinois	1,824	456
Geothermal	PacifiCorp and BHE Renewables	California and Utah	370	370
		Total	38,556	29,527

Additionally, Berkshire Hathaway Energy has electric generating facilities that are under construction in Iowa and Minnesota as of December 31, 2016 having total Facility Net Capacity and Net Owned Capacity of 2,072 MW.

The right to construct and operate each Registrant's electric transmission and distribution facilities and interstate natural gas pipelines across certain property was obtained in most circumstances through negotiations and, where necessary, through prescription, eminent domain or similar rights. PacifiCorp, MidAmerican Energy, Nevada Power, Sierra Pacific, Northern Natural Gas and Kern River in the United States; Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc in Great Britain; and AltaLink in Alberta, Canada continue to have the power of eminent domain or similar rights in each of the jurisdictions in which they operate their respective facilities, but the United States and Canadian utilities do not have the power of eminent domain with respect to governmental, Native American or Canadian First Nations' tribal lands. Although the main Kern River pipeline crosses the Moapa Indian Reservation, all facilities in the Moapa Indian Reservation are located within a utility corridor that is reserved to the United States Department of Interior, Bureau of Land Management.

With respect to real property, each of the electric transmission and distribution facilities and interstate natural gas pipelines fall into two basic categories: (1) parcels that are owned in fee, such as certain of the electric generating facilities, electric substations, natural gas compressor stations, natural gas meter stations and office sites; and (2) parcels where the interest derives from leases, easements (including prescriptive easements), rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for the construction, operation and maintenance of the electric transmission and distribution facilities and interstate natural gas pipelines. Each Registrant believes it has satisfactory title or interest to all of the real property making up their respective facilities in all material respects.

Item 3. Legal Proceedings

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

Item 4. Mine Safety Disclosures

Information regarding Berkshire Hathaway Energy's and PacifiCorp's mine safety violations and other legal matters disclosed in accordance with Section 1503(a) of the Dodd-Frank Reform Act is included in Exhibit 95 to this Form 10-K.

PART II

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

BERKSHIRE HATHAWAY ENERGY

BHE's common stock is owned by Berkshire Hathaway, Mr. Walter Scott, Jr., a member of BHE's Board of Directors (along with family members and related entities), and Mr. Gregory E. Abel, BHE's Chairman, President and Chief Executive Officer, and has not been registered with the SEC pursuant to the Securities Act of 1933, as amended, listed on a stock exchange or otherwise publicly held or traded. BHE has not declared or paid any cash dividends to its common shareholders since Berkshire Hathaway acquired an equity ownership interest in BHE in March 2000, and does not presently anticipate that it will declare any dividends on its common stock in the foreseeable future.

For a discussion of restrictions that limit BHE's and its subsidiaries' ability to pay dividends on their common stock, refer to Note 17 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K.

PACIFICORP

All common stock of PacifiCorp is held by its parent company, PPW Holdings LLC, which is a direct, wholly owned subsidiary of BHE. PacifiCorp declared and paid dividends to PPW Holdings LLC of $875 million in 2016 and $950 million in 2015.

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

MIDAMERICAN FUNDING AND MIDAMERICAN ENERGY

All common stock of MidAmerican Energy is held by its parent company, MHC, which is a direct, wholly owned subsidiary of MidAmerican Funding. MidAmerican Funding is an Iowa limited liability company whose membership interest is held solely by BHE.

For a discussion of regulatory restrictions that limit MidAmerican Energy's ability to pay dividends on common stock, refer to "Debt Authorizations and Related Matters" in MidAmerican Energy's Item 7 in this Form 10-K and to Note 9 of the Notes to Financial Statements of MidAmerican Energy in Item 8 of this Form 10-K.

NEVADA POWER

All common stock of Nevada Power is held by its parent company, NV Energy, which is an indirect, wholly owned subsidiary of BHE. Nevada Power declared and paid dividends to NV Energy of $469 million in 2016 and $13 million in 2015.

SIERRA PACIFIC

All common stock of Sierra Pacific is held by its parent company, NV Energy. Sierra Pacific declared and paid dividends to NV Energy of $51 million in 2016 and $7 million in 2015.

Item 6. Selected Financial Data

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

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Item 8. Financial Statements and Supplementary Data

Berkshire Hathaway Energy Company and its subsidiaries
Consolidated Financial Section

Item 6. Selected Financial Data

The following table sets forth the Company's selected consolidated historical financial data, which should be read in conjunction with the information in Item 7 of this Form 10-K and with the Company's historical Consolidated Financial Statements and notes thereto in Item 8 of this Form 10-K. The selected consolidated historical financial data has been derived from the Company's audited historical Consolidated Financial Statements and notes thereto (in millions).

	Years Ended December 31,				
	2016(1)	2015(1)	2014(1)	2013(1)	2012
Consolidated Statement of Operations Data:					
Operating revenue	$ 17,422	$ 17,880	$ 17,326	$ 12,635	$ 11,548
Net income	2,570	2,400	2,122	1,676	1,495
Net income attributable to BHE shareholders	2,542	2,370	2,095	1,636	1,472

	As of December 31,				
	2016(1)	2015(1)	2014(1)	2013(1)	2012
Consolidated Balance Sheet Data:					
Total assets(2)(3)	$ 85,440	$ 83,618	$ 81,816	$ 69,591	$ 52,212
Short-term debt	1,869	974	1,445	232	887
Long-term debt, including current maturities:					
BHE senior debt(3)	7,818	7,814	7,810	6,575	4,592
BHE subordinated debt	944	2,944	3,794	2,594	—
Subsidiary debt(3)	27,354	27,214	26,848	22,645	16,007
Total BHE shareholders' equity	24,327	22,401	20,442	18,711	15,742

(1) Reflects the completion of the AltaLink acquisition from December 1, 2014 and the NV Energy acquisition from December 19, 2013.

(2) In December 2015, the Company retrospectively adopted Accounting Standards Update No. 2015-17, which resulted in the reclassification of certain deferred income tax balances previously recognized within other current assets in the amounts of $291 million, $211 million and $119 million, as of December 31, 2014, 2013 and 2012, respectively, as reductions in noncurrent deferred income tax liabilities.

(3) In December 2015, the Company retrospectively adopted Accounting Standards Update 2015-03, which resulted in the reclassification of certain deferred debt issuance costs previously recognized within other assets in the amounts of $50 million, $41 million and $29 million, as of December 31, 2014, 2013 and 2012, respectively, as reductions in BHE senior debt, and certain deferred debt issuance costs previously recognized within other assets in the amounts of $147 million, $157 million and $107 million, as of December 31, 2014, 2013 and 2012, respectively, as reductions in subsidiary debt.

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

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

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 entities, corporate functions and intersegment eliminations. Effective January 1, 2016, MidAmerican Energy transferred the assets and liabilities of its unregulated retail services business to MidAmerican Energy Services, LLC, a subsidiary of BHE. Prior period amounts have been changed to reflect this activity in BHE and Other.

Results of Operations

Overview

Net income for the Company's reportable segments for the years ended December 31 is summarized as follows (in millions):

	2016	2015	Change		2015	2014	Change	
Net income attributable to BHE shareholders:								
PacifiCorp	$ 764	$ 697	$ 67	10%	$ 697	$ 700	$ (3)	— %
MidAmerican Funding	532	442	90	20	442	393	49	12
NV Energy	359	379	(20)	(5)	379	354	25	7
Northern Powergrid	342	422	(80)	(19)	422	412	10	2
BHE Pipeline Group	249	243	6	2	243	230	13	6
BHE Transmission	214	186	28	15	186	56	130	*
BHE Renewables	179	124	55	44	124	121	3	2
HomeServices	127	104	23	22	104	83	21	25
BHE and Other	(224)	(227)	3	1	(227)	(254)	27	11
Total net income attributable to BHE shareholders	$ 2,542	$ 2,370	$ 172	7	$ 2,370	$ 2,095	$ 275	13

* Not meaningful

Net income attributable to BHE shareholders increased $172 million for 2016 compared to 2015 due to the following:

- PacifiCorp's net income increased $67 million due to higher margins of $86 million, lower operations and maintenance expenses of $18 million, and higher production tax credits of $8 million, partially offset by higher depreciation and amortization of $13 million, lower AFUDC of $9 million and higher property taxes of $5 million. Margins increased primarily due to lower purchased electricity costs, higher retail rates, lower coal-fueled generation and lower natural gas costs, partially offset by lower wholesale electricity revenue from lower volumes and prices. Retail customer volumes decreased by 0.6% due to lower commercial customer usage in Utah and lower industrial customer usage primarily in Utah and Oregon, partially offset by an increase in the average number of residential customers in Utah and Oregon and commercial customers in Utah and the impacts of weather on residential customer volumes.

- MidAmerican Funding's net income increased $90 million due to higher electric margins of $172 million, higher production tax credits of $39 million and lower fossil-fueled generation operations and maintenance of $35 million, partially offset by higher depreciation and amortization of $72 million from wind-powered generation and other plant placed in-service and an accrual related to an Iowa regulatory revenue sharing arrangement, a pre-tax gain of $13 million in 2015 on the sale of a generating facility lease, higher interest expense of $12 million and higher income taxes from the effects of ratemaking and higher pre-tax income. Electric margins reflect higher retail sales volumes, higher retail rates in Iowa, lower energy costs, higher wholesale revenue and higher transmission revenue.

- NV Energy's net income decreased $20 million due to higher operating expense of $27 million, higher depreciation and amortization of $11 million due to higher plant in-service and lower electric margins of $2 million, partially offset by lower interest expense of $12 million. Operating expense increased due to benefits from changes in contingent liabilities in 2015 and regulatory disallowances in 2016. Electric margins decreased primarily due to lower transmission and wholesale revenue and lower customer usage offset by higher customer growth.

- Northern Powergrid's net income decreased $80 million due to the stronger United States dollar of $47 million, lower distribution revenues mainly due to the recovery in 2015 of the December 2013 customer rebate and unfavorable movements in regulatory provisions, higher depreciation of $25 million from additional assets placed in service, higher write-offs of hydrocarbon well exploration costs of $15 million and higher interest expense of $7 million. These adverse variances were partially offset by higher smart meter revenue, lower operating expenses and lower income tax expense primarily due to the resolution of income tax return claims from prior years partially offset by decreased deferred income tax benefits due to a 1% reduction in the United Kingdom corporate income tax rate in 2016 compared to a 2% reduction in 2015.

- BHE Pipeline Group's net income increased $6 million due to higher storage revenues, lower operating expenses and lower interest expense due to the early redemption in December 2015 of the 6.667% Senior Notes at Kern River, partially offset by lower transportation revenues and higher depreciation expense.

- BHE Transmission's net income increased $28 million from higher earnings at AltaLink of $22 million and at BHE U.S. Transmission of $6 million. Earnings at AltaLink increased primarily due to additional assets placed in-service and favorable regulatory decisions, partially offset by a $26 million pre-tax impairment related to nonregulated natural gas-fueled generation assets and the stronger United States dollar of $5 million. BHE U.S. Transmission's earnings improved primarily from higher equity earnings at Electric Transmission Texas, LLC from continued investment and additional plant placed in-service.
- BHE Renewables' net income increased $55 million due to three tax equity investments reaching commercial operations in 2016 and higher production at wind projects, including additional capacity placed in-service in 2016 at two projects, partially offset by lower solar revenues mainly due to forced outages and higher depreciation expense due to additional wind and solar capacity placed in-service.
- HomeServices' net income increased $23 million due to a 9% increase in closed brokerage units, primarily due to acquired brokerage businesses, a 2% increase in average home sales prices and higher earnings at existing mortgage and franchise businesses.
- BHE and Other net loss improved $3 million due to lower interest expense, an increase in consolidated deferred state income tax benefits and higher investment returns, partially offset by higher United States income taxes on foreign earnings.

Net income attributable to BHE shareholders increased $275 million for 2015 compared to 2014 due to the following:

- PacifiCorp's net income decreased $3 million due to the recognition of insurance recoveries for a fire claim in 2014, higher depreciation and amortization of $35 million, lower AFUDC of $25 million and higher property taxes, partially offset by higher margins of $109 million and lower production tax credits of $9 million. Margins increased primarily due to higher retail rates, lower purchased electricity prices, lower natural gas generation and costs, Utah mine disposition costs in 2014 and lower coal generation, partially offset by higher purchased electricity volumes, lower wholesale electricity revenue from lower volumes and prices and lower retail customer volumes. Customer volumes decreased 0.7% 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, an increase in the average number of commercial customers in Utah and the impacts of weather on residential, commercial and irrigation customer volumes.
- MidAmerican Funding's net income increased $49 million due to higher regulated electric margins of $119 million, higher production tax credits of $27 million and lower fossil-fueled generation maintenance of $10 million, partially offset by higher depreciation and amortization of $56 million due to wind-powered generation and other plant placed in-service, lower AFUDC of $27 million, lower regulated natural gas margins of $12 million due to warmer temperatures in 2015 and higher interest expense of $9 million due to the issuance of first mortgage bonds in April 2014 and October 2015. Regulated electric margins increased primarily due to higher retail rates in Iowa and changes in rate structure related to seasonal pricing, lower purchased power costs, a lower average cost of fuel for generation and higher transmission revenue, partially offset by lower wholesale revenue. Electric retail customer volumes increased 1.2% as a result of strong industrial growth, partially offset by warmer winter temperatures compared to 2014.
- NV Energy's net income increased $25 million due to higher electric margins of $76 million and lower interest expense of $21 million, partially offset by higher depreciation and amortization of $31 million due to higher regulatory amortizations and higher operating expense of $30 million, primarily related to energy efficiency costs. Electric margins increased primarily due to higher electric retail customer volumes of 2.4% from increased customer usage and growth and the impacts of weather.
- Northern Powergrid's net income increased $10 million due to income tax benefits of $41 million from a 2% reduction in the United Kingdom corporate income tax rate, higher distribution revenue from recovery of the December 2013 customer rebate and favorable movements in regulatory provisions, and lower write-offs of hydrocarbon well exploration costs of $22 million, partially offset by lower tariff rates and distributed units and the stronger United States dollar of $34 million.
- BHE Pipeline Group's net income increased $13 million due to lower operating expenses of $28 million primarily at Northern Natural Gas as a result of lower in-line inspection, hydrostatic testing and other maintenance project costs and higher transportation revenues of $7 million, partially offset by higher depreciation expense of $8 million and lower other income of $6 million due to a contract restructuring at Northern Natural Gas that expired in 2015.
- BHE Transmission's net income increased $130 million from higher earnings at AltaLink of $120 million due to the acquisition of AltaLink on December 1, 2014, and at BHE U.S. Transmission of $10 million primarily related to lower acquisition and project development costs.

- BHE Renewables' net income increased $3 million due to higher earnings of $18 million from solar projects primarily due to additional solar capacity at the Solar Star and Topaz Projects being placed in-service, partially offset by lower earnings of $18 million at CE Generation due to lower revenue from lower short run avoided cost pricing.
- HomeServices' net income increased $21 million due to higher earnings at existing brokerage, mortgage and franchise businesses, due to higher closed units, and acquired brokerage businesses, partially offset by $12 million of gains in 2014 from the acquisition of interests in equity method investments.
- BHE and Other net loss improved $27 million due to lower income tax expense from favorable consolidated deferred state income tax benefits and United States income taxes on foreign earnings, partially offset by higher interest expense from debt issuances in the fourth quarter of 2014.

Reportable Segment Results

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

	2016	2015	Change		2015	2014	Change	
Operating revenue:								
PacifiCorp	$ 5,201	$ 5,232	$ (31)	(1)%	$ 5,232	$ 5,252	$ (20)	— %
MidAmerican Funding	2,631	2,515	116	5	2,515	2,844	(329)	(12)
NV Energy	2,895	3,351	(456)	(14)	3,351	3,241	110	3
Northern Powergrid	995	1,140	(145)	(13)	1,140	1,283	(143)	(11)
BHE Pipeline Group	978	1,016	(38)	(4)	1,016	1,078	(62)	(6)
BHE Transmission	502	592	(90)	(15)	592	62	530	*
BHE Renewables	743	728	15	2	728	623	105	17
HomeServices	2,801	2,526	275	11	2,526	2,144	382	18
BHE and Other	676	780	(104)	(13)	780	799	(19)	(2)
Total operating revenue	$ 17,422	$ 17,880	$ (458)	(3)	$ 17,880	$ 17,326	$ 554	3
Operating income:								
PacifiCorp	$ 1,427	$ 1,344	$ 83	6 %	$ 1,344	$ 1,308	$ 36	3 %
MidAmerican Funding	566	451	115	25	451	395	56	14
NV Energy	770	812	(42)	(5)	812	791	21	3
Northern Powergrid	494	593	(99)	(17)	593	674	(81)	(12)
BHE Pipeline Group	455	464	(9)	(2)	464	439	25	6
BHE Transmission	92	260	(168)	(65)	260	16	244	*
BHE Renewables	256	255	1	—	255	314	(59)	(19)
HomeServices	212	184	28	15	184	125	59	47
BHE and Other	(21)	(35)	14	40	(35)	(16)	(19)	*
Total operating income	$ 4,251	$ 4,328	$ (77)	(2)	$ 4,328	$ 4,046	$ 282	7

* Not meaningful

PacifiCorp

Operating revenue decreased $31 million for 2016 compared to 2015 due to lower wholesale and other revenue of $88 million, partially offset by higher retail revenue of $57 million. Wholesale and other revenue decreased due to lower wholesale volumes of $65 million and lower average wholesale prices of $25 million. The increase in retail revenue was primarily due to higher retail rates. Retail customer volumes decreased by 0.6% due to lower commercial customer usage in Utah and lower industrial customer usage primarily in Utah and Oregon, partially offset by an increase in the average number of residential customers in Utah and Oregon and commercial customers in Utah and the impacts of weather on residential customer volumes.

Operating income increased $83 million for 2016 compared to 2015 due to higher margins of $86 million and lower operations and maintenance expenses of $18 million, partially offset by higher depreciation and amortization of $13 million and higher property taxes of $5 million. Margins increased due to lower energy costs of $117 million, partially offset by lower operating revenue of $31 million. Energy costs decreased primarily due to lower purchased electricity costs, lower coal-fueled generation and lower natural gas costs, partially offset by higher gas-fueled generation and higher coal costs. Operations and maintenance expenses decreased primarily due to lower plant maintenance costs associated with reduced generation and lower labor and benefit costs due to lower headcount, partially offset by a Washington rate case decision disallowing returns on recent selective catalytic reduction projects.

Operating revenue decreased $20 million for 2015 compared to 2014 due to lower wholesale and other revenue of $113 million, partially offset by higher retail revenue of $93 million. Wholesale and other revenue decreased due to lower wholesale volumes of $55 million, lower REC revenue of $31 million and lower average wholesale prices of $27 million. The increase in retail revenue was due to higher retail rates of $109 million, partially offset by lower retail customer volumes of $16 million. Customer volumes decreased 0.7% 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, an increase in the average number of commercial customers in Utah and the impacts of weather on residential, commercial and irrigation customer volumes.

Operating income increased $36 million for 2015 compared to 2014 due to higher margins of $109 million, partially offset by the recognition of insurance recoveries for a fire claim in 2014, higher depreciation and amortization of $35 million primarily due to higher plant in-service including the Lake Side 2 natural gas-fueled generating facility ("Lake Side 2") placed in-service in May 2014 and higher property taxes. Margins increased due to lower energy costs of $129 million, partially offset by the lower operating revenue. Energy costs decreased due to lower purchased electricity prices, lower natural gas generation, lower average cost of natural gas, Utah mine disposition costs in 2014 and lower coal generation, partially offset by higher purchased electricity volumes and lower net deferrals of incurred net power costs.

MidAmerican Funding

Operating revenue increased $116 million for 2016 compared to 2015 due to higher electric operating revenue of $148 million, partially offset by lower natural gas operating revenue of $24 million and lower other operating revenue of $8 million. Electric operating revenue increased due to higher retail revenue of $112 million and higher wholesale and other revenue of $36 million. Retail revenue increased $47 million from higher electric rates in Iowa effective January 1, 2016, $33 million from non-weather-related usage factors, including higher industrial sales volumes and $30 million from warmer cooling season temperatures, net of warmer winter temperatures in 2016. Electric retail customer volumes increased 3.8% from the favorable impact of temperatures and industrial growth. Electric wholesale and other revenue increased primarily due to higher wholesale prices of $25 million and higher transmission revenue of $17 million related to Multi-Value Projects, which are expected to increase as projects are constructed, partially offset by lower wholesale volumes of $6 million. Natural gas operating revenue decreased due to a lower average per-unit cost of gas sold of $42 million, which is offset in cost of sales, and 0.5% lower retail sales volumes, primarily from warmer winter temperatures in 2016, partially offset by 10.1% higher wholesale volumes. Other operating revenue decreased primarily due to the completion of major projects of a nonregulated utility construction subsidiary in 2015.

Operating income increased $115 million for 2016 compared to 2015 due to higher electric operating income of $112 million and higher natural gas operating income of $4 million. Electric operating income increased due to the higher operating revenue, lower energy costs of $24 million reflecting lower coal-fueled generation in part due to greater wind-powered generation, higher purchased power volumes and higher natural gas-fueled generation, lower fossil-fueled generation maintenance of $24 million from planned outages in 2015 and lower generation operations costs of $7 million, partially offset by higher depreciation and amortization of $70 million from wind-powered generation and other plant placed in-service and an accrual related to an Iowa regulatory revenue sharing arrangement, higher other generation maintenance of $13 million primarily from the addition of wind turbines and higher operating expense recovered through bill riders of $14 million. Natural gas operating income increased due to lower distribution costs.

Operating revenue decreased $329 million for 2015 compared to 2014 due to lower natural gas operating revenue of $335 million and lower other operating revenue of $14 million, partially offset by higher electric operating revenue of $20 million. Natural gas operating revenue decreased due to a lower average per-unit cost of gas sold of $290 million, which is offset in cost of sales, and 16.7% lower retail sales volumes primarily from warmer winter temperatures in 2015, partially offset by higher wholesale volumes. Electric operating revenue increased due to higher retail revenue of $84 million, partially offset by lower wholesale and other revenue of $64 million. Retail revenue increased $70 million from higher electric rates primarily in Iowa, $16 million from non-weather-related usage factors and $8 million from higher recoveries through bill riders and adjustment clauses, which is substantially offset in operating expense, partially offset by $10 million from the impact of warmer winter 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 volumes increased 1.2% as a result of strong industrial growth, net of the impact of temperatures compared to 2014. Electric wholesale and other revenue decreased primarily due to lower average wholesale prices of $62 million and lower wholesale volumes of $24 million, partially offset by higher transmission revenue of $25 million related to Multi-Value Projects.

Operating income increased $56 million for 2015 compared to 2014 due to higher electric operating income of $66 million, partially offset by lower natural gas operating income of $11 million. Electric operating income increased due to lower energy costs of $99 million from a lower average cost of fuel for generation and lower purchased power costs, the higher retail rates and changes in rate structure related to seasonal pricing, the higher transmission revenue and lower fossil-fueled generation maintenance from planned major outages in 2014 of $10 million, partially offset by the lower wholesale revenue and higher depreciation and amortization of $56 million due to wind generation and other plant placed in-service. Natural gas operating income decreased due to the 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 decreased $456 million for 2016 compared to 2015 due to lower electric operating revenue of $427 million, lower natural gas operating revenue of $27 million, primarily due to lower energy rates partially offset by higher customer usage, and lower other operating revenue of $2 million. Electric operating revenue decreased due to lower retail revenue of $414 million and lower wholesale, transmission and other revenue of $13 million. Retail revenue decreased primarily due to $431 million from lower retail rates primarily from lower energy costs which are passed on to customers through deferred energy adjustment mechanisms and $28 million from lower customer usage, partially offset by $38 million from higher customer growth, $11 million from higher customer usage primarily due to the impacts of weather and $4 million of higher energy efficiency rate revenue, which is offset in operating expense. Electric retail customer volumes were flat compared to 2015.

Operating income decreased $42 million for 2016 compared to 2015 due to higher operating expense of $27 million, primarily due to benefits from changes in contingent liabilities in 2015, regulatory disallowances in 2016 and higher energy efficiency program costs, which is offset in operating revenue, higher depreciation and amortization of $11 million due to higher plant in-service and lower electric margins of $2 million. Electric margins were lower due to the lower electric operating revenue offset by lower energy costs of $425 million. Energy costs decreased due to lower net deferred power costs of $413 million and a lower average cost of fuel for generation of $69 million, partially offset by higher purchased power costs of $57 million.

Operating revenue increased $110 million for 2015 compared to 2014 due to higher electric operating revenue of $94 million and higher natural gas operating revenue of $12 million due to increased customer usage and higher rates. Electric operating revenue increased due to higher retail revenue of $82 million and higher wholesale and other revenue of $12 million primarily due to higher transmission revenue. Retail revenue was higher due to $45 million from higher customer growth, $31 million of higher energy efficiency rate revenue, which is offset in operating expense, and $22 million of higher customer usage primarily due to the impacts of weather, partially offset by $18 million from lower retail rates primarily from lower energy costs which are passed on to customers through deferred energy adjustment mechanisms. Electric retail customer volumes increased 2.4% compared to 2014.

Operating income increased $21 million for 2015 compared to 2014 due to higher electric margins of $76 million from the higher electric operating revenue, partially offset by higher energy costs of $18 million, higher depreciation and amortization of $31 million and higher operating expense of $30 million, primarily related to energy efficiency program costs, which is offset in operating revenue. Energy costs increased due to higher net deferred power costs of $247 million, partially offset by a lower average cost of fuel for generation of $228 million.

Northern Powergrid

Operating revenue decreased $145 million for 2016 compared to 2015 due to the stronger United States dollar of $127 million, lower distribution revenues of $28 million and lower contracting revenue of $5 million, partially offset by higher smart meter revenue of $18 million. Distribution revenue decreased due to the recovery in 2015 of the December 2013 customer rebate of $22 million, lower units distributed and unfavorable movements on regulatory provisions of $8 million, partially offset by higher tariff rates. Operating income decreased $99 million for 2016 compared to 2015 mainly due to the stronger United States dollar of $61 million, the lower distribution revenue, higher depreciation expense of $25 million from additional distribution and smart meter assets placed in-service and higher write-offs of hydrocarbon well exploration costs of $15 million, partially offset by the higher smart meter revenue and lower pension costs.

Operating revenue decreased $143 million for 2015 compared to 2014 due to the stronger United States dollar of $90 million, lower distribution revenue of $43 million and lower contracting and other revenue of $10 million. Distribution revenue decreased due to lower tariff rates of $99 million mainly reflecting the impact of the new price control period effective April 1, 2015 and lower units distributed of $6 million, partially offset by the recovery in 2015 of the December 2013 customer rebate of $41 million and favorable movements in regulatory provisions of $21 million. Operating income decreased $81 million for 2015 compared to 2014 due to the stronger United States dollar of $47 million, the lower distribution revenue and higher pension costs of $9 million, partially offset by lower write-offs of hydrocarbon well exploration costs of $22 million.

BHE Pipeline Group

Operating revenue decreased $38 million for 2016 compared to 2015 due to lower gas sales of $25 million at Northern Natural Gas related to system and operational balancing activities, which are largely offset in cost of sales, and a $20 million reduction in transportation revenues, partially offset by a $7 million increase in storage revenues at Northern Natural Gas. Operating income decreased $9 million for 2016 compared to 2015 due to the lower transportation revenues and higher depreciation expense, partially offset by the higher storage revenues and lower operating expenses.

Operating revenue decreased $62 million for 2015 compared to 2014 due to lower gas sales of $68 million related to system and operational balancing activities, which are largely offset in cost of sales, partially offset by higher transportation revenues. Operating income increased $25 million for 2015 compared to 2014 due to the higher transportation revenues and lower operating expenses of $28 million primarily at Northern Natural Gas as a result of lower in-line inspection, hydrostatic testing and other maintenance project costs, partially offset by higher depreciation expense of $8 million.

BHE Transmission

Operating revenue decreased $90 million for 2016 compared to 2015 due to a one-time reduction of $200 million from the 2015-2016 GTA decision received in May 2016 at AltaLink, AltaLink's change to the flow through method of recognizing income tax expense of $45 million, which is offset in income tax expense, and the stronger United States dollar of $20 million, partially offset by $175 million from additional assets placed in-service and recovery of higher costs. Operating income decreased $168 million for 2016 compared to 2015 due to the lower operating revenues at AltaLink, a $26 million impairment related to nonregulated natural gas-fueled generation assets and the stronger United States dollar of $5 million. The 2015-2016 GTA decision required AltaLink to refund $200 million to customers in 2016 through reduced monthly billings for the change from receiving cash during construction for the return on construction work-in-progress in rate base to recording allowance for borrowed and equity funds used during construction related to construction expenditures during the 2011 to 2014 time period. This amount is offset with higher capitalized interest and allowance for equity funds.

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 2015 from AltaLink were $592 million and $262 million, respectively, compared with $62 million and $31 million, respectively, for 2014. Operating income also increased for 2015 compared to 2014 due to lower acquisition and project development costs.

BHE Renewables

Operating revenue increased $15 million for 2016 compared to 2015 due to higher wind generation at the Pinyon Pines and Jumbo Road projects of $21 million, additional wind capacity placed in-service of $14 million, a favorable change in the valuation of a power purchase agreement derivative of $6 million and higher hydro generation of $6 million, partially offset by lower geothermal generation of $18 million and lower solar generation of $14 million mainly due to forced outages. Operating income increased $1 million for 2016 compared to 2015 due to the higher operating revenue being offset by higher depreciation expense of $14 million from additional wind and solar capacity placed in-service.

Operating revenue increased $105 million for 2015 compared to 2014 due to an increase of $160 million as additional solar and wind capacity was placed in-service and an increase from the acquisition of the remaining 50% interest in CE Generation in June 2014 of $55 million, partially offset by an $88 million decrease at CalEnergy Philippines due to the adoption of ASC 853 and lower wind generation at existing projects. Operating income decreased $59 million for 2015 compared to 2014 as the higher operating revenue was more than offset by higher operating expense of $101 million and higher depreciation and amortization of $64 million. Operating expense increased due to $69 million from the CE Generation acquisition, $22 million from additional solar and wind capacity placed in-service. Depreciation and amortization increased due to $52 million from additional solar and wind capacity placed in-service and $33 million from the CE Generation acquisition, partially offset by a $23 million decrease at CalEnergy Philippines due to the adoption of ASC 853.

HomeServices

Operating revenue increased $275 million for 2016 compared to 2015 due to a 9% increase in closed brokerage units and a 2% increase in average home sales prices. The increase in operating revenue was due to an increase from existing businesses totaling $106 million and an increase in acquired businesses totaling $169 million. The increase in existing businesses reflects a 2% increase in closed brokerage units, a 2% increase in average home sales prices and $34 million of higher mortgage revenue. Operating income increased $28 million for 2016 compared to 2015 due to the higher mortgage revenue and from acquired brokerage businesses, partially offset by lower earnings at existing brokerage businesses due to higher operating expenses offset by higher net revenues.

Operating revenue increased $382 million for 2015 compared to 2014 due to a 12.0% increase in closed brokerage units and a 3% increase in average home sales prices. The increase in operating revenue was due to an increase from existing businesses totaling $225 million and an increase in acquired businesses totaling $157 million. The increase in existing businesses reflects an 8% increase in closed brokerage units and a 2% increase in average home sales prices. Operating income increased $59 million for 2015 compared to 2014 due to higher revenues, partially offset by higher costs, primarily commission expense, at existing businesses of $53 million and higher earnings at acquired businesses of $6 million.

BHE and Other

Operating revenue decreased $104 million for 2016 compared to 2015 primarily due to lower electricity volumes and natural gas prices at MidAmerican Energy Services, LLC. Operating loss improved $14 million for 2016 compared to 2015 primarily due to higher margins of $10 million at MidAmerican Energy Services, LLC.

Operating revenue decreased $19 million for 2015 compared to 2014 primarily due to lower natural gas prices and volumes, partially offset by higher electricity prices and volumes, at MidAmerican Energy Services, LLC. Operating loss increased $19 million for 2015 compared to 2014 primarily due to lower margins of $4 million at MidAmerican Energy Services, LLC and higher other operating costs.

Consolidated Other Income and Expense Items

Interest Expense

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

	2016	2015	Change		2015	2014	Change	
Subsidiary debt	$ 1,378	$ 1,392	$ (14)	(1)%	$ 1,392	$ 1,280	$ 112	9%
BHE senior debt and other	411	408	3	1	408	353	55	16
BHE junior subordinated debentures	65	104	(39)	(38)	104	78	26	33
Total interest expense	$ 1,854	$ 1,904	$ (50)	(3)	$ 1,904	$ 1,711	$ 193	11

Interest expense on subsidiary debt decreased $14 million for 2016 compared to 2015 due to debt issuances at MidAmerican Funding, NV Energy, Northern Powergrid, AltaLink and BHE Renewables, scheduled maturities and principal payments and by the impact of foreign currency exchange rate movements of $23 million.

Interest expense on BHE junior subordinated debentures decreased $39 million for 2016 compared to 2015 due to $2.0 billion of repayments in 2016.

Interest expense on subsidiary debt increased $112 million for 2015 compared to 2014 due to $132 million from the acquisition of AltaLink in December 2014, partially offset by $11 million from the impact of the foreign currency exchange rate.

Interest expense on BHE senior debt and other increased $55 million for 2015 compared to 2014 due to the issuance of $1.5 billion of BHE senior debt in December 2014, partially offset by scheduled maturities of BHE senior debt totaling $250 million in 2014.

Interest expense on BHE junior subordinated debentures increased $26 million for 2015 compared to 2014 from $1.5 billion of junior subordinated debentures issued to certain Berkshire Hathaway subsidiaries in 2014, partially offset by $850 million of repayments in 2015.

Capitalized Interest

Capitalized interest increased $65 million for 2016 compared to 2015 primarily due to $96 million recorded in the second quarter of 2016 from the 2015-2016 GTA decision received in May 2016 at AltaLink, which is offset in operating revenue, partially offset by lower construction work-in-progress balances at AltaLink and PacifiCorp.

Capitalized interest decreased $15 million for 2015 compared to 2014 as $25 million from AltaLink was more than offset by lower construction work-in-progress balances at BHE Renewables, MidAmerican Energy and PacifiCorp.

Allowance for Equity Funds

Allowance for equity funds increased $67 million for 2016 compared to 2015 primarily due to $104 million recorded in the second quarter of 2016 from the 2015-2016 GTA decision received in May 2016 at AltaLink, which is offset in operating revenue, partially offset by lower construction work-in-progress balances at AltaLink and PacifiCorp.

Allowance for equity funds decreased $7 million for 2015 compared to 2014 as $29 million from AltaLink was more than offset by lower construction work-in-progress balances at MidAmerican Energy and PacifiCorp.

Interest and Dividend Income

Interest and dividend income increased $13 million for 2016 compared to 2015 primarily due to a dividend from BYD Company Limited.

Interest and dividend income increased $69 million for 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.

Income Tax Expense

Income tax expense decreased $47 million for 2016 compared to 2015 and the effective tax rate was 14% for 2016 and 16% for 2015. The effective tax rate decreased due to higher production tax credits of $107 million, the resolution of income tax return claims from prior years of $28 million and favorable impacts of rate making of $24 million, partially offset by unfavorable United States income taxes on foreign earnings of $46 million and lower deferred income tax benefits of $23 million due to a 1% reduction in the United Kingdom corporate income tax rate in 2016 compared to a 2% reduction in 2015.

Income tax expense decreased $139 million for 2015 compared to 2014 and the effective tax rate was 16% for 2015 and 23% for 2014. The effective tax rate decreased due to deferred income tax benefits of $39 million from a 2% reduction in the United Kingdom corporate income tax rate, favorable United States income taxes on foreign earnings of $36 million, favorable consolidated state income tax benefits of $35 million, favorable impacts of rate making of $34 million and higher production tax credits recognized of $33 million.

Federal renewable electricity production tax credits are earned as energy from qualifying wind-powered generating facilities is produced and sold based on a per kilowatt rate as prescribed pursuant to the applicable federal income tax law and are eligible for the credit for 10 years from the date the qualifying generating facilities are placed in-service. A credit of $0.023 per kilowatt hour was applied to 2016, 2015 and 2014 production, respectively, which resulted in $398 million, $291 million and $258 million, respectively, in production tax credits.

Equity Income

Equity income for the years ended December 31 is summarized as follows (in millions):

	2016	2015	Change		2015	2014	Change	
Equity income:								
ETT	$ 95	$ 81	$ 14	17%	$ 81	$ 80	$ 1	1%
Agua Caliente	25	24	1	4	24	27	(3)	(11)
CE Generation	—	—	—	*	—	(8)	8	*
HomeServices	6	6	—	*	6	2	4	*
Other	(3)	4	(7)	*	4	8	(4)	(50)
Total equity income (loss)	$ 123	$ 115	$ 8	7	$ 115	$ 109	$ 6	6

* Not meaningful

Equity income increased $8 million for 2016 compared to 2015 primarily due to higher equity earnings of $14 million at Electric Transmission Texas, LLC from continued investment and additional plant placed in-service, partially offset by a pre-tax loss of $9 million from tax equity investments at BHE Renewables.

Equity income increased $6 million for 2015 compared to 2014 primarily due to the acquisition of the remaining interest in CE Generation on June 1, 2014 resulting in consolidation of the activity effective on this date.

Liquidity and Capital Resources

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

As of December 31, 2016, the Company's total net liquidity was $4.7 billion as follows (in millions):

	BHE	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	AltaLink	Other	Total
Cash and cash equivalents	$ 33	$ 17	$ 15	$ 330	$ 65	$ 10	$ 251	$ 721
Credit facilities	2,000	1,000	609	650	185	986	915	6,345
Less:								
Short-term debt	(834)	(270)	(99)	—	—	(289)	(377)	(1,869)
Tax-exempt bond support and letters of credit	(7)	(142)	(220)	(80)	—	(8)	—	(457)
Net credit facilities	1,159	588	290	570	185	689	538	4,019
Total net liquidity	$ 1,192	$ 605	$ 305	$ 900	$ 250	$ 699	$ 789	$ 4,740
Credit facilities:								
Maturity dates	2019	2018, 2019	2017, 2018	2018	2020	2017, 2018, 2021	2017, 2018	

Refer to Note 8 of the Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding the Company's credit facilities, letters of credit, equity commitments and other related items.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2016 and 2015 were $6.1 billion and $7.0 billion, respectively. The change was primarily due to lower income tax receipts of $618 million and payment for the USA Power final judgment and postjudgment interest of $123 million.

Net cash flows from operating activities for the years ended December 31, 2015 and 2014 were $7.0 billion and $5.1 billion, respectively. Higher income tax receipts of $1.0 billion, improved operating results of $653 million, including $403 million from AltaLink, and other changes in working capital were partially offset by higher interest payments of $179 million. As of December 31, 2015, the Company had a current income tax receivable of $319 million.

The timing of the Company's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods and assumptions for each payment date.

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 benefited in 2015 due to bonus depreciation on qualifying assets placed in-service and for production tax credits earned on qualifying projects.

In December 2015, the Protecting Americans from Tax Hikes Act of 2015 ("PATH") was signed into law, extending bonus depreciation for qualifying property acquired and placed in-service before January 1, 2020 (bonus depreciation rates will be 50% in 2015-2017, 40% in 2018, and 30% in 2019), with an additional year for certain longer lived assets. Production tax credits were extended and phased-out for wind power and other forms of non-solar renewable energy projects that begin construction before the end of 2019. Production tax credits are maintained at full value through 2016, at 80% of value in 2017, at 60% of value in 2018, and 40% of value in 2019. Investment tax credits were extended and phased-down for solar projects that are under construction before the end of 2021 (investment tax credit rates are 30% through 2019, 26% in 2020 and 22% in 2021; they revert to the statutory rate of 10% thereafter). As a result of PATH, the Company's cash flows from operations are expected to benefit due to bonus depreciation on qualifying assets placed in-service through 2019, production tax credits through 2029 and investment tax credits earned on qualifying wind and solar projects through 2021, respectively.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2016 and 2015 were $(5.7) billion and $(6.2) billion, respectively. The change was primarily due to lower capital expenditures of $785 million, partially offset by higher funding of tax equity investments. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Net cash flows from investing activities for the years ended December 31, 2015 and 2014 were $(6.2) billion and $(9.4) billion, respectively. The change was primarily due to lower acquisitions totaling $164 million in 2015 compared to $3.0 billion in 2014 ($2.7 billion for AltaLink) and lower capital expenditures of $680 million, partially offset by changes in restricted cash and investments of $201 million and higher equity method investments of $165 million.

Financing Activities

Net cash flows from financing activities for the year ended December 31, 2016 were $(690) million. Sources of cash totaled $3.2 billion and consisted mainly of proceeds from subsidiary debt totaling $2.3 billion and net proceeds from short-term debt of $880 million. Uses of cash totaled $3.9 billion and consisted mainly of $1.8 billion for repayments of subsidiary debt and repayments of BHE subordinated debt totaling $2 billion.

Net cash flows from financing activities for the year ended December 31, 2015 were $(255) million. Sources of cash totaled $2.5 billion and consisted of proceeds from subsidiary debt. Uses of cash totaled $2.7 billion and consisted mainly of $1.4 billion for repayments of subsidiary debt, repayments of BHE subordinated debt totaling $850 million and net repayments of short-term debt of $421 million.

Net cash flows from financing activities for the year ended December 31, 2014 were $3.7 billion. Sources of cash totaled $5.3 billion and consisted of proceeds from BHE junior subordinated debentures totaling $1.5 billion, proceeds from subsidiary debt totaling $1.3 billion, proceeds from BHE senior debt totaling $1.5 billion and net proceeds from short-term debt totaling $1.1 billion. Uses of cash totaled $1.6 billion and consisted mainly of $1.0 billion for repayments of subsidiary debt and repayments of BHE senior and subordinated debt totaling $550 million.

On December 1, 2014, BHE completed its acquisition of AltaLink. Following completion of the acquisition, AltaLink became an indirect wholly owned subsidiary of BHE. Under the terms of the Share Purchase Agreement, dated May 1, 2014, among BHE and SNC-Lavalin Group Inc., BHE paid C$3.1 billion (US$2.7 billion) in cash to SNC-Lavalin Group Inc. 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. On December 4, 2014, BHE issued $350 million of 2.40% Senior Notes due 2020, $400 million of 3.50% Senior Notes due 2025 and $750 million of 4.50% Senior Notes due 2045 and used the proceeds to repay commercial paper borrowings.

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

Future Uses of Cash

The Company has available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, the issuance of equity and other sources. These sources are expected to provide funds required for current operations, capital expenditures, acquisitions, investments, debt retirements and other capital requirements. The availability and terms under which BHE and 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 for the years ended December 31 are as follows (in millions):

	Historical			**Forecast**		
	2014	**2015**	**2016**	**2017**	**2018**	**2019**
PacifiCorp	$ 1,066	$ 916	$ 903	$ 850	$ 985	$ 1,620
MidAmerican Funding	1,527	1,448	1,637	1,852	1,525	1,780
NV Energy	558	571	529	457	385	376
Northern Powergrid	675	674	579	626	520	420
BHE Pipeline Group	257	240	226	305	217	309
BHE Transmission	222	966	466	369	290	234
BHE Renewables	2,221	1,034	719	741	76	86
HomeServices	17	16	20	30	20	18
BHE and Other	12	10	11	21	19	16
Total	$ 6,555	$ 5,875	$ 5,090	$ 5,251	$ 4,037	$ 4,859

	Historical			Forecast		
	2014	2015	2016	2017	2018	2019
Wind generation	$ 1,052	$ 1,177	$ 1,712	$ 1,166	$ 1,197	$ 2,178
Solar generation	1,896	786	69	654	18	2
Electric transmission	547	936	448	393	247	160
Environmental	258	134	70	139	102	23
Other developmental projects	178	63	48	197	42	174
Other operating	2,624	2,779	2,743	2,702	2,431	2,322
Total	$ 6,555	$ 5,875	$ 5,090	$ 5,251	$ 4,037	$ 4,859

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

- Wind generation includes the following:
  - Construction of wind-powered generating facilities at MidAmerican Energy totaling $943 million for 2016, $931 million for 2015 and $767 million for 2014. MidAmerican Energy placed in-service 600 MW (nominal ratings) during 2016, 608 MW (nominal ratings) during 2015 and 511 MW (nominal ratings) during 2014. In August 2016, the IUB issued an order approving ratemaking principles related to MidAmerican Energy's construction of up to 2,000 MW (nominal ratings) of additional wind-powered generating facilities expected to be placed in-service in 2017 through 2019. MidAmerican Energy expects to spend $826 million in 2017, $853 million in 2018 and $1.4 billion in 2019 for these additional wind-powered generating facilities. The ratemaking principles establish a cost cap of $3.6 billion, including AFUDC, and a fixed rate of return on equity of 11.0% over the proposed 40-year useful lives of those facilities in any future Iowa rate proceeding. The cost cap ensures that as long as total costs are below the cap, the investment will be deemed prudent in any future Iowa rate proceeding. Additionally, the ratemaking principles modify the revenue sharing mechanism currently in effect. The revised sharing mechanism will be effective in 2018 and will be triggered each year by actual equity returns if they are above the weighted average return on equity for MidAmerican Energy calculated annually. Pursuant to the change in revenue sharing, MidAmerican Energy will share 100% of the revenue in excess of this trigger with customers. Such revenue sharing will reduce coal and nuclear generation rate base, which is intended to mitigate future base rate increases. MidAmerican Energy expects all of these wind-powered generating facilities to qualify for 100% of federal production tax credits available.
  - Construction of wind-powered generating facilities at BHE Renewables totaling $456 million for 2016, $246 million for 2015, and $286 million for 2014. The Marshall Wind Project with a total capacity of 72 MW achieved commercial operation in April 2016 and the Grande Prairie Wind Project with a total capacity of 400 MW achieved commercial operation in November 2016. The Jumbo Road Project with a total capacity of 300 MW achieved commercial operation in April 2015.
  - Equipment purchases totaling $324 million in 2016 for the purposes of repowering certain existing wind-powered generating facilities at PacifiCorp and MidAmerican Energy and the construction of new wind-powered generating facilities at PacifiCorp and BHE Renewables. The repowering projects entail the replacement of significant components of older turbines. Planned spending for the repowered and new wind-powered generating facilities totals $323 million in 2017, $313 million in 2018 and $740 million in 2019. The energy production from the repowered and the new facilities is expected to qualify for 100% of the federal renewable electricity production tax credits available for ten years once the equipment is placed in-service.
- Solar generation includes the following:
  - BHE Solar acquired the 110-MW Alamo 6 project located in Texas in January 2017 for approximately $385 million.
  - BHE Solar spent $56 million in 2016 and $3 million in 2015 for construction of the community solar gardens in Minnesota and expects to spend an additional $153 million in 2017 and $6 million in 2018. The completed project will be comprised of 28 locations with a nominal facilities capacity of 96 MW.
  - Construction of the Solar Star Projects totaling $10 million for 2016, $689 million for 2015 and $1.1 billion for 2014. Both projects declared July 1, 2015 as the commercial operation date in accordance with the power purchase agreements. Final completion under the engineering, procurement and construction agreements occurred November 30, 2015 and project completion was achieved under the financing documents on December 15, 2015.

- Construction of the Topaz Project totaling $49 million for 2015 and $814 million for 2014. 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.

- Electric transmission includes investments for ALP's transmission system including directly assigned projects from the AESO, PacifiCorp's costs primarily associated with main grid reinforcement and the Energy Gateway Transmission Expansion Program and MidAmerican Energy's MVPs approved by the MISO for the construction of approximately 250 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.
- Other operating includes ongoing distribution systems infrastructure needed at the Utilities and Northern Powergrid and investments in routine expenditures for generation, transmission, distribution and other infrastructure needed to serve existing and expected demand.

Contractual Obligations

The Company has contractual cash obligations that may affect its consolidated financial condition. The following table summarizes the Company's material contractual cash obligations as of December 31, 2016 (in millions):

	Payments Due By Periods				
	2017	2018-2019	2020-2021	2022 and After	Total
BHE senior debt	$ 400	$ 1,000	$ 350	$ 6,125	$ 7,875
BHE junior subordinated debentures	—	—	—	944	944
Subsidiary debt	606	4,643	2,025	20,202	27,476
Interest payments on long-term debt(1)	1,789	3,257	2,853	18,269	26,168
Short-term debt	1,869	—	—	—	1,869
Fuel, capacity and transmission contract commitments(1)	2,370	2,995	2,218	10,053	17,636
Construction commitments(1)	852	115	2	4	973
Operating leases and easements(1)	141	223	160	1,085	1,609
Other(1)	339	496	435	871	2,141
Total contractual cash obligations	$ 8,366	$ 12,729	$ 8,043	$ 57,553	$ 86,691

(1) Not reflected on the Consolidated Balance Sheets.

The Company has other types of commitments that arise primarily from unused lines of credit, letters of credit or relate to construction and other development costs (Liquidity and Capital Resources included within this Item 7 and Note 8), uncertain tax positions (Note 11) and asset retirement obligations (Note 13), which have not been included in the above table because the amount and timing of the cash payments are not certain. Refer, where applicable, to the respective referenced note in Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Additionally, the Company has invested in projects sponsored by third parties, commonly referred to as tax equity investments. Under the terms of these tax equity investments, the Company has entered into equity capital contribution agreements with the project sponsors that require contributions. The Company has made contributions of $170 million in 2015 and $584 million in 2016 and expects to contribute $87 million in 2017 and $201 million in 2018 pursuant to these equity capital contribution agreements as the various projects achieve commercial operation. Once a project achieves commercial operation, the Company enters into a partnership agreement with the project sponsor that directs and allocates the operating profits and tax benefits from the project.

Regulatory Matters

The Company is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further discussion regarding the Company's general regulatory framework and current regulatory matters.

Quad Cities Generating Station Operating Status

Exelon Generation Company, LLC ("Exelon Generation"), the operator of Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station") of which MidAmerican Energy has a 25% ownership interest, announced on June 2, 2016, its intention to shut down Quad Cities Station on June 1, 2018, as a result of Illinois not passing adequate legislation and Quad Cities Station not clearing the 2019-2020 PJM Interconnection, L.L.C. capacity auction. MidAmerican Energy expressed to Exelon Generation its desire for the continued operation of the facility through the end of its operating license in 2032 and worked with Exelon Generation on solutions to that end. In December 2016, Illinois passed legislation creating a zero emission standard. The zero emission standard requires the Illinois Power Agency to purchase zero emission credits and recover the costs from certain ratepayers in Illinois, subject to certain limitations. The proceeds from the zero emission credits will provide Exelon Generation additional revenue through 2027 as an incentive for continued operation of Quad Cities Station. For the nuclear assets already in rate base, MidAmerican Energy's customers will not be charged for the subsidy, and MidAmerican Energy will not receive additional revenue from the subsidy.

Environmental Laws and Regulations

The Company is subject to federal, state, local and foreign laws and regulations regarding air and water quality, RPS, 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 its current and future operations. In addition to imposing continuing compliance obligations and capital expenditure requirements, 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 laws and regulations are subject to interpretation that may ultimately be resolved by the courts. Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion regarding environmental laws and regulations and "Liquidity and Capital Resources" for discussion of the Company's forecast environmental-related capital expenditures.

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 December 31, 2016, the applicable entities' 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 December 31, 2016, the Company would have been required to post $490 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 14 of Notes to Consolidated Financial Statements for a discussion of the Company's collateral requirements specific to its derivative contracts.

Inflation

Historically, overall inflation and changing prices in the economies where BHE's subsidiaries operate have not had a significant impact on the Company's consolidated financial results. In the United States and Canada, the Regulated Businesses operate under cost-of-service based rate structures administered by various state and provincial commissions and the FERC. Under these rate structures, the Regulated Businesses are allowed to include prudent costs in their rates, including the impact of inflation. The price control formula used by the Northern Powergrid Distribution Companies incorporates the rate of inflation in determining rates charged to customers. BHE's subsidiaries attempt to minimize the potential impact of inflation on their operations through the use of fuel, energy and other cost adjustment clauses and bill riders, by employing prudent risk management and hedging strategies and by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances. There can be no assurance that such actions will be successful.

Off-Balance Sheet Arrangements

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

As of December 31, 2016, the Company's investments that are accounted for under the equity method had short- and long-term debt of $2.4 billion, unused revolving credit facilities of $348 million and letters of credit outstanding of $88 million. As of December 31, 2016, the Company's pro-rata share of such short- and long-term debt was $1.2 billion, unused revolving credit facilities was $143 million and outstanding letters of credit was $43 million. The entire amount of the Company's pro-rata share of the outstanding short- and long-term debt and unused revolving credit facilities is non-recourse to the Company. The entire amount of the Company's pro-rata share of the outstanding letters of credit is recourse to the Company. Although the Company is generally not required to support debt service obligations of its equity investees, default with respect to this non-recourse short- and long-term debt could result in a loss of invested equity.

New Accounting Pronouncements

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

Critical Accounting Estimates

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

Accounting for the Effects of Certain Types of Regulation

The Regulated Businesses prepare their financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, the Regulated Businesses defer the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

The Company continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit the Regulated Businesses' ability to recover their costs. The Company believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at both the federal, state and provincial levels. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI"). Total regulatory assets were $4.5 billion and total regulatory liabilities were $3.1 billion as of December 31, 2016. Refer to Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Regulated Businesses' regulatory assets and liabilities.

Derivatives

The Company is exposed to the impact of market fluctuations in commodity prices, interest rates and foreign currency exchange rates. The Company is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk primarily through BHE's ownership of the Utilities as they have an obligation to serve retail customer load in their regulated service territories. The Company also provides nonregulated retail electricity and natural gas services in competitive markets. The Utilities' load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity, wholesale electricity that is purchased and sold, and natural gas supply for retail customers. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. Interest rate risk exists on variable-rate short- and long-term debt, future debt issuances and mortgage commitments. Additionally, BHE is exposed to foreign currency exchange rate risk from its business operations and investments in Great Britain and Canada. Each of BHE's business platforms has established a risk management process that is designed to identify, assess, manage, mitigate, monitor and report each of the various types of risk involved in its business. The Company employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage its commodity price, interest rate, and foreign currency exchange rate risk. 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. Refer to Notes 14 and 15 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's derivative contracts.

Measurement Principles

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which 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. As of December 31, 2016, the Company had a net derivative liability of $143 million related to contracts valued using either quoted prices or forward price curves based upon 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. The assumptions used in these models are important because any changes in assumptions could have a significant impact on the estimated fair value of the contracts. As of December 31, 2016, the Company had a net derivative asset of $66 million related to contracts where the Company uses internal models with significant unobservable inputs.

Classification and Recognition Methodology

The majority of the Company's commodity derivative contracts are probable of inclusion in the rates of its rate-regulated subsidiaries, and changes in the estimated fair value of derivative contracts are generally recorded as net regulatory assets or liabilities. Accordingly, amounts are generally not recognized in earnings until the contracts are settled and the forecasted transaction has occurred. As of December 31, 2016, the Company had $148 million recorded as net regulatory assets related to derivative contracts on the Consolidated Balance Sheets.

Impairment of Goodwill and Long-Lived Assets

The Company's Consolidated Balance Sheet as of December 31, 2016 includes goodwill of acquired businesses of $9.0 billion. The Company evaluates goodwill for impairment at least annually and completed its annual review as of October 31. Additionally, no indicators of impairment were identified as of December 31, 2016. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. The Company uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings; and an appropriate discount rate. Estimated future cash flows are impacted by, among other factors, growth rates, changes in regulations and rates, ability to renew contracts and estimates of future commodity prices. In estimating future cash flows, the Company incorporates current market information, as well as historical factors. Refer to Note 21 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's goodwill.

The Company evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2016, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

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

Pension and Other Postretirement Benefits

Certain of the Company's subsidiaries sponsor defined benefit pension and other postretirement benefit plans that cover the majority of employees. The Company recognizes the funded status of the defined benefit pension and other postretirement benefit plans on the Consolidated Balance Sheets. Funded status is the fair value of plan assets minus the benefit obligation as of the measurement date. As of December 31, 2016, the Company recognized a net liability totaling $451 million for the funded status of the defined benefit pension and other postretirement benefit plans. As of December 31, 2016, amounts not yet recognized as a component of net periodic benefit cost that were included in net regulatory assets totaled $791 million and in AOCI totaled $603 million.

The expense and benefit obligations relating to these defined benefit pension and other postretirement benefit plans are based on actuarial valuations. Inherent in these valuations are key assumptions, including discount rates, expected long-term rate of return on plan assets and healthcare cost trend rates. These key assumptions are reviewed annually and modified as appropriate. The Company believes that the assumptions utilized in recording obligations under the plans are reasonable based on prior plan experience and current market and economic conditions. Refer to Note 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for disclosures about the defined benefit pension and other postretirement benefit plans, including the key assumptions used to calculate the funded status and net periodic benefit cost for these plans as of and for the year ended December 31, 2016.

The Company chooses a discount rate based upon high quality debt security investment yields in effect as of the measurement date that corresponds to the expected benefit period. The pension and other postretirement benefit liabilities increase as the discount rate is reduced.

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

The Company chooses a healthcare cost trend rate that reflects the near and long-term expectations of increases in medical costs and corresponds to the expected benefit payment periods. The healthcare cost trend rate is assumed to gradually decline to 5.00% by 2025, at which point the rate of increase is assumed to remain constant. Refer to Note 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for healthcare cost trend rate sensitivity disclosures.

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

	Domestic Plans					
	Pension Plans		Other Postretirement Benefit Plans		United Kingdom Pension Plan	
	+0.5%	-0.5%	+0.5%	-0.5%	+0.5%	-0.5%
Effect on December 31, 2016						
Benefit Obligations:						
Discount rate	$ (147)	$ 163	$ (31)	$ 34	$ (189)	$ 216
Effect on 2016 Periodic Cost:						
Discount rate	$ (6)	$ 6	$ —	$ —	$ (16)	$ 16
Expected rate of return on plan assets	(12)	12	(3)	3	(9)	9

A variety of factors affect the funded status of the plans, including asset returns, discount rates, mortality assumptions, plan changes and the Company's funding policy for each plan.

Income Taxes

In determining the Company's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by the Company's various regulatory jurisdictions. The Company's income tax returns are subject to continuous examinations by federal, state, local and foreign income tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. The Company recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of the Company's federal, state, local and foreign income tax examinations is uncertain, the Company believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations, if any, is not expected to have a material impact on the Company's consolidated financial results. Refer to Note 11 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's income taxes.

The Utilities are required to pass income tax benefits related to certain property-related basis differences and other various differences on to their customers in certain state jurisdictions. As of December 31, 2016, these amounts were recognized as a regulatory asset of $1.6 billion and a regulatory liability of $25 million and will be included in regulated rates when the temporary differences reverse.

The Company has not established deferred income taxes on the undistributed foreign earnings of Northern Powergrid or AltaLink or the related currency translation adjustment that have been determined by management to be reinvested indefinitely. The cumulative undistributed foreign earnings were approximately $3.0 billion as of December 31, 2016. The Company periodically evaluates its capital requirements. If circumstances change in the future and a portion of Northern Powergrid's or AltaLink's undistributed earnings were repatriated, the dividends would be subject to taxation in the United States. However, any United States income tax liability would be offset, in part, by available United States income tax credits with respect to corporate income taxes previously paid in the United Kingdom and Canada. Because of the availability of foreign income tax credits, it is not practicable to determine the United States income tax liability that would be recognized if such cumulative earnings were not reinvested indefinitely. The Company has established deferred income taxes on all other undistributed foreign earnings. If opportunities become available to repatriate any available cash without triggering incremental United States income tax expense, the Company may distribute certain foreign earnings of Northern Powergrid and AltaLink.

Revenue Recognition - Unbilled Revenue

Revenue from energy business customers is recognized as electricity or natural gas is delivered or services are provided. The determination of customer billings is based on a systematic reading of meters, fixed reservation charges based on contractual quantities and rates or, in the case of the Great Britain distribution businesses, when information is received from the national settlement system. At the end of each month, energy provided to customers since the date of the last meter reading is estimated, and the corresponding unbilled revenue is recorded. Unbilled revenue was $643 million as of December 31, 2016. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns, total volumes supplied to the system, line losses, economic impacts and composition of sales among customer classes. Unbilled revenue is reversed in the following month and billed revenue is recorded based on the subsequent meter readings.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company's Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. The Company's significant market risks are primarily associated with commodity prices, interest rates, equity prices, foreign currency exchange rates and the extension of credit to counterparties with which the Company transacts. The following discussion addresses the significant market risks associated with the Company's business activities. Each of the Company's business platforms has established guidelines for credit risk management. Refer to Notes 2 and 14 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's contracts accounted for as derivatives.

Commodity Price Risk

The Company is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk primarily through BHE's ownership of the Utilities as they have an obligation to serve retail customer load in their regulated service territories. The Company also provides nonregulated retail electricity and natural gas services in competitive markets. The Utilities' load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity, wholesale electricity that is purchased and sold, and natural gas supply for retail customers. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. The Company does not engage in a material amount of proprietary trading activities. 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 does not hedge all of its commodity price risk, thereby exposing the unhedged portion to changes in market prices. The Company's exposure to commodity price risk is generally limited by its ability to include commodity costs in regulated rates, which is subject to regulatory lag that occurs between the time the costs are incurred and when the costs are included in regulated rates, as well as the impact of any customer sharing resulting from cost adjustment mechanisms.

The table that follows summarizes the Company's price risk on commodity contracts accounted for as derivatives, excluding collateral netting of $74 million and $103 million, respectively, as of December 31, 2016 and 2015, and shows the effects of a hypothetical 10% increase and 10% decrease in forward market prices with the contracted or expected volumes. The selected hypothetical change does not reflect what could be considered the best or worst case scenarios (dollars in millions).

	Fair Value - Net Asset (Liability)	Estimated Fair Value after Hypothetical Change in Price	
		10% increase	10% decrease
As of December 31, 2016:			
Not designated as hedging contracts	$ (71)	$ (37)	$ (105)
Designated as hedging contracts	(16)	19	(51)
Total commodity derivative contracts	$ (87)	$ (18)	$ (156)
As of December 31, 2015			
Not designated as hedging contracts	$ (186)	$ (148)	$ (224)
Designated as hedging contracts	(47)	(4)	(89)
Total commodity derivative contracts	$ (233)	$ (152)	$ (313)

The settled cost of certain of the Company's commodity derivative contracts not designated as hedging contracts is included in regulated rates and, therefore, net unrealized gains and losses associated with interim price movements on commodity derivative contracts do not expose the Company to earnings volatility. As of December 31, 2016 and 2015, a net regulatory asset of $148 million and $250 million, respectively, was recorded related to the net derivative liability of $71 million and $186 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. For the Company's commodity derivative contracts designated as hedging contracts, net unrealized gains and losses associated with interim price movements on commodity derivative contracts, to the extent the hedge is considered effective, generally do not expose the Company to earnings volatility. The settled cost of these commodity derivative contracts is generally included in regulated rates. Consolidated financial results would be negatively impacted if the costs of wholesale electricity, natural gas or fuel are higher than what is included in regulated rates, including the impacts of adjustment mechanisms.

Interest Rate Risk

The Company is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt, future debt issuances and mortgage commitments. 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. As a result of the fixed interest rates, the Company's fixed-rate long-term debt does not expose the Company to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if the Company were to reacquire all or a portion of these instruments prior to their maturity. The nature and amount of the Company's short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 8, 9, 10, and 15 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of the Company's short- and long-term debt.

As of December 31, 2016 and 2015, the Company had short- and long-term variable-rate obligations totaling $4.2 billion and $5.5 billion, respectively, that expose the Company to the risk of increased interest expense in the event of increases in short-term interest rates. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on the Company's consolidated annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2016 and 2015.

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. Changes in fair value of agreements designated as cash flow hedges are reported in accumulated other comprehensive income to the extent the hedge is effective until the forecasted transaction occurs. Changes in fair value of agreements not designated as hedging contracts are recognized in earnings. As of December 31, 2016 and 2015, the Company had variable-to-fixed interest rate swaps with notional amounts of $714 million and $653 million, respectively, to protect the Company against an increase in interest rates. Additionally, as of December 31, 2016 and 2015, the Company had mortgage commitments, net, with notional amounts of $309 million and $312 million, respectively, to protect the Company against an increase in interest rates. The fair value of the Company's interest rate derivative contracts was a net derivative asset of $10 million as of December 31, 2016, and a net derivative liability of $4 million as of December 31, 2015. A hypothetical 20 basis point increase and a 20 basis point decrease in the interest rate would not have a material impact on the Company.

Equity Price Risk

Market prices for equity securities are subject to fluctuation and consequently the amount realized in the subsequent sale of an investment may significantly differ from the reported market value. Fluctuation in the market price of a security may result from perceived changes in the underlying economic characteristics of the investee, the relative price of alternative investments and general market conditions.

As of December 31, 2016 and 2015, the Company's investment in BYD Company Limited common stock represented approximately 75% and 76%, respectively, of the total fair value of the Company's equity securities. The majority of the Company's remaining equity securities related to certain trust funds in which realized and unrealized gains and losses are recorded as a net regulatory liability since the Company expects to recover costs for these activities through regulated rates. The following table summarizes the Company's investment in BYD Company Limited as of December 31, 2016 and 2015 and the effects of a hypothetical 30% increase and a 30% decrease in market price as of those dates. The selected hypothetical change does not reflect what could be considered the best or worst case scenarios (dollars in millions).

	Fair Value	Hypothetical Price Change	Estimated Fair Value after Hypothetical Change in Prices	Hypothetical Percentage Increase (Decrease) in BHE Shareholders' Equity
As of December 31, 2016	$ 1,185	30% increase	$ 1,541	1%
		30% decrease	830	(1)
As of December 31, 2015	$ 1,238	30% increase	$ 1,609	1%
		30% decrease	867	(1)

Foreign Currency Exchange Rate Risk

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

Northern Powergrid's functional currency is the British pound. As of December 31, 2016, a 10% devaluation in the British pound to the United States dollar would result in the Company's Consolidated Balance Sheet being negatively impacted by a $356 million cumulative translation adjustment in AOCI. A 10% devaluation in the average currency exchange rate would have resulted in lower reported earnings for Northern Powergrid of $34 million in 2016.

AltaLink's functional currency is the Canadian dollar. As of December 31, 2016, a 10% devaluation in the Canadian dollar to the United States dollar would result in the Company's Consolidated Balance Sheet being negatively impacted by a $275 million cumulative translation adjustment in AOCI. A 10% devaluation in the average currency exchange rate would have resulted in lower reported earnings for AltaLink of $15 million in 2016.

Credit Risk

Domestic Regulated Operations

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.

As of December 31, 2016, PacifiCorp's aggregate credit exposure from wholesale activities totaled $136 million, based on settlement and mark-to-market exposures, net of collateral. As of December 31, 2016, $135 million, or 99.6%, of PacifiCorp's credit exposure was with counterparties having investment grade credit ratings by either Moody's Investor Service or Standard & Poor's Rating Services. As of December 31, 2016, two counterparties comprised $87 million, or 64%, of the aggregate credit exposure. The two counterparties are rated investment grade by Moody's Investor Service and Standard & Poor's Rating Services, and PacifiCorp is not aware of any factors that would likely result in a downgrade of the counterparties' credit ratings to below investment grade over the remaining term of transactions outstanding as of December 31, 2016.

Substantially all of MidAmerican Energy's electric wholesale sales revenue results from participation in regional transmission organizations ("RTOs"), including the MISO and the PJM. MidAmerican Energy's share of historical losses from defaults by other RTO market participants has not been material. Additionally, as of December 31, 2016, MidAmerican Energy's aggregate direct credit exposure from electric wholesale marketing counterparties was not material.

As of December 31, 2016, NV Energy's aggregate credit exposure from energy related transactions, based on settlement and mark-to-market exposures, net of collateral, was not material.

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

Northern Powergrid

The Northern Powergrid Distribution Companies charge fees for the use of their distribution systems to supply companies. The supply companies, which purchase electricity from generators and traders and sell the electricity to end-use customers, use the Northern Powergrid Distribution Companies' distribution networks pursuant to the multilateral "Distribution Connection and Use of System Agreement." The Northern Powergrid Distribution Companies' customers are concentrated in a small number of electricity supply businesses with RWE Npower PLC accounting for approximately 22% of distribution revenue in 2016. The industry operates in accordance with a framework which sets credit limits for each supply business based on its credit rating or payment history and requires them to provide credit cover if their value at risk (measured as being equivalent to 45 days usage) exceeds the credit limit. Acceptable credit typically is provided in the form of a parent company guarantee, letter of credit or an escrow account. Ofgem has indicated that, provided the Northern Powergrid Distribution Companies have implemented credit control, billing and collection in line with best practice guidelines and can demonstrate compliance with the guidelines or are able to satisfactorily explain departure from the guidelines, any bad debt losses arising from supplier default will be recovered through an increase in future allowed income. Losses incurred to date have not been material.

AltaLink

AltaLink's primary source of operating revenue is the AESO, an entity rated AA- by Standard and Poor's. Because of the dependence on a single customer, any material failure of the customer to fulfill its obligations would significantly impair AltaLink's ability to meet its existing and future obligations. Total operating revenue for AltaLink was $502 million for the year ended December 31, 2016.

BHE Renewables

BHE Renewables owns independent power projects in the United States and the Philippines that generally have separate project financing agreements. These projects source of operating revenue is derived primarily from long-term power purchase agreements with single customers, primarily utilities, which expire between 2017 and 2040. Because of the dependence generally from a single customer at each project, any material failure of the customer to fulfill its obligations would significantly impair that project's ability to meet its existing and future obligations. Total operating revenue for BHE Renewables was $743 million for the year ended December 31, 2016.

Other Energy Business

MidAmerican Energy Services, LLC ("MES") is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with financial institutions and other market participants. Credit risk may be concentrated to the extent that MES' counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, MES analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, MES enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. If required, MES exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2016, MES' aggregate credit exposure from energy related transactions, based on settlement and mark-to-market exposures, net of collateral, was not material.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Berkshire Hathaway Energy Company and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2016. Our audits also included the financial statement schedules listed in the Index at Item 15(a)(ii). These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Berkshire Hathaway Energy Company and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 24, 2017

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

	As of December 31,	
	2016	**2015**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 721	$ 1,108
Trade receivables, net	1,751	1,785
Income taxes receivable	—	319
Inventories	925	882
Mortgage loans held for sale	359	335
Other current assets	917	814
Total current assets	4,673	5,243
Property, plant and equipment, net	62,509	60,769
Goodwill	9,010	9,076
Regulatory assets	4,307	4,155
Investments and restricted cash and investments	3,945	3,367
Other assets	996	1,008
Total assets	$ 85,440	$ 83,618

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

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

	As of December 31,	
	2016	2015
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 1,317	$ 1,564
Accrued interest	454	469
Accrued property, income and other taxes	389	372
Accrued employee expenses	261	264
Regulatory liabilities	187	402
Short-term debt	1,869	974
Current portion of long-term debt	1,006	1,148
Other current liabilities	830	896
Total current liabilities	6,313	6,089
Regulatory liabilities	2,933	2,631
BHE senior debt	7,418	7,814
BHE junior subordinated debentures	944	2,944
Subsidiary debt	26,748	26,066
Deferred income taxes	13,879	12,685
Other long-term liabilities	2,742	2,854
Total liabilities	60,977	61,083
Commitments and contingencies (Note 16)		
Equity:		
BHE shareholders' equity:		
Common stock - 115 shares authorized, no par value, 77 shares issued and outstanding	—	—
Additional paid-in capital	6,390	6,403
Retained earnings	19,448	16,906
Accumulated other comprehensive loss, net	(1,511)	(908)
Total BHE shareholders' equity	24,327	22,401
Noncontrolling interests	136	134
Total equity	24,463	22,535
Total liabilities and equity	$ 85,440	$ 83,618

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

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

	Years Ended December 31,		
	2016	**2015**	**2014**
Operating revenue:			
Energy	$ 14,621	$ 15,354	$ 15,182
Real estate	2,801	2,526	2,144
Total operating revenue	17,422	17,880	17,326
Operating costs and expenses:			
Energy:			
Cost of sales	4,315	5,079	5,732
Operating expense	3,707	3,732	3,501
Depreciation and amortization	2,560	2,399	2,028
Real estate	2,589	2,342	2,019
Total operating costs and expenses	13,171	13,552	13,280
Operating income	4,251	4,328	4,046
Other income (expense):			
Interest expense	(1,854)	(1,904)	(1,711)
Capitalized interest	139	74	89
Allowance for equity funds	158	91	98
Interest and dividend income	120	107	38
Other, net	36	39	42
Total other income (expense)	(1,401)	(1,593)	(1,444)
Income before income tax expense and equity income	2,850	2,735	2,602
Income tax expense	403	450	589
Equity income	123	115	109
Net income	2,570	2,400	2,122
Net income attributable to noncontrolling interests	28	30	27
Net income attributable to BHE shareholders	$ 2,542	$ 2,370	$ 2,095

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

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

	Years Ended December 31,		
	2016	**2015**	**2014**
Net income	$ 2,570	$ 2,400	$ 2,122
Other comprehensive loss, net of tax:			
Unrecognized amounts on retirement benefits, net of tax of $11, $17 and $19	(9)	52	69
Foreign currency translation adjustment	(583)	(680)	(314)
Unrealized (losses) gains on available-for-sale securities, net of tax of $(19), $129 and $(84)	(30)	225	(134)
Unrealized gains (losses) on cash flow hedges, net of tax of $13, $(7) and $(13)	19	(11)	(18)
Total other comprehensive loss, net of tax	(603)	(414)	(397)
Comprehensive income	1,967	1,986	1,725
Comprehensive income attributable to noncontrolling interests	28	30	27
Comprehensive income attributable to BHE shareholders	$ 1,939	$ 1,956	$ 1,698

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

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

	BHE Shareholders' Equity						
	Common		Additional Paid-in	Retained	Accumulated Other Comprehensive	Noncontrolling	Total
	Shares	Stock	Capital	Earnings	Loss, Net	Interests	Equity
Balance, December 31, 2013	77	$ —	$ 6,390	$ 12,418	$ (97)	$ 105	$ 18,816
Net income	—	—	—	2,095	—	17	2,112
Other comprehensive loss	—	—	—	—	(397)	—	(397)
Distributions	—	—	—	—	—	(22)	(22)
Other equity transactions	—	—	33	—	—	31	64
Balance, December 31, 2014	77	—	6,423	14,513	(494)	131	20,573
Adoption of ASC 853	—	—	—	56	—	11	67
Net income	—	—	—	2,370	—	18	2,388
Other comprehensive loss	—	—	—	—	(414)	—	(414)
Distributions	—	—	—	—	—	(21)	(21)
Common stock purchases	—	—	(3)	(33)	—	—	(36)
Other equity transactions	—	—	(17)	—	—	(5)	(22)
Balance, December 31, 2015	77	—	6,403	16,906	(908)	134	22,535
Net income	—	—	—	2,542	—	14	2,556
Other comprehensive loss	—	—	—	—	(603)	—	(603)
Distributions	—	—	—	—	—	(20)	(20)
Other equity transactions	—	—	(13)	—	—	8	(5)
Balance, December 31, 2016	77	$ —	$ 6,390	$ 19,448	$ (1,511)	$ 136	$ 24,463

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

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

	Years Ended December 31,		
	2016	**2015**	**2014**
Cash flows from operating activities:			
Net income	$ 2,570	$ 2,400	$ 2,122
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	2,591	2,428	2,057
Allowance for equity funds	(158)	(91)	(98)
Equity income, net of distributions	(67)	(38)	(79)
Changes in regulatory assets and liabilities	(34)	356	(168)
Deferred income taxes and amortization of investment tax credits	1,090	1,265	2,335
Other, net	(80)	11	147
Changes in other operating assets and liabilities, net of effects from acquisitions:			
Trade receivables and other assets	(158)	(9)	(44)
Derivative collateral, net	32	(14)	(70)
Pension and other postretirement benefit plans	(79)	(11)	86
Accrued property, income and other taxes	377	877	(1,117)
Accounts payable and other liabilities	(28)	(194)	(25)
Net cash flows from operating activities	6,056	6,980	5,146
Cash flows from investing activities:			
Capital expenditures	(5,090)	(5,875)	(6,555)
Acquisitions, net of cash acquired	(66)	(164)	(2,956)
(Increase) decrease in restricted cash and investments	(36)	(28)	173
Purchases of available-for-sale securities	(141)	(144)	(150)
Proceeds from sales of available-for-sale securities	191	142	118
Equity method investments	(570)	(202)	(37)
Other, net	(34)	41	(11)
Net cash flows from investing activities	(5,746)	(6,230)	(9,418)
Cash flows from financing activities:			
Proceeds from BHE senior debt	—	—	1,478
Proceeds from BHE junior subordinated debentures	—	—	1,500
Repayments of BHE senior debt and junior subordinated debentures	(2,000)	(850)	(550)
Common stock purchases	—	(36)	—
Proceeds from subsidiary debt	2,327	2,479	1,257
Repayments of subsidiary debt	(1,831)	(1,354)	(971)
Net proceeds from (repayments of) short-term debt	879	(421)	1,055
Other, net	(65)	(73)	(44)
Net cash flows from financing activities	(690)	(255)	3,725
Effect of exchange rate changes	(7)	(4)	(11)
Net change in cash and cash equivalents	(387)	491	(558)
Cash and cash equivalents at beginning of period	1,108	617	1,175
Cash and cash equivalents at end of period	$ 721	$ 1,108	$ 617

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

(1) Organization and Operations

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 Canada Holdings Corporation ("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.

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of BHE and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. The Consolidated Statements of Operations include the revenue and expenses of any acquired entities from the date of acquisition. Intercompany accounts and transactions have been eliminated.

Use of Estimates in Preparation of Financial Statements

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

Accounting for the Effects of Certain Types of Regulation

PacifiCorp, MidAmerican Energy, Nevada Power, Sierra Pacific, Northern Natural Gas, Kern River and ALP (the "Regulated Businesses") prepare their financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, the Regulated Businesses defer the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

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

Fair Value Measurements

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

Cash Equivalents and Restricted Cash and Investments

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

Investments

The Company's management determines the appropriate classification of investments in debt and equity securities at the acquisition date and reevaluates the classification at each balance sheet date. Investments and restricted cash and investments that management does not intend to use or is restricted from using in current operations are presented as noncurrent on the Consolidated Balance Sheets.

Available-for-sale securities are carried at fair value with realized gains and losses, as determined on a specific identification basis, recognized in earnings and unrealized gains and losses recognized in AOCI, net of tax. Realized and unrealized gains and losses on securities in a trust related to the decommissioning of nuclear generation assets are recorded as a net regulatory liability since the Company expects to recover costs for these activities through regulated rates. Trading securities are carried at fair value with realized and unrealized gains and losses recognized in earnings. Held-to-maturity securities are carried at amortized cost, reflecting the ability and intent to hold the securities to maturity.

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

Investments gains and losses arise when investments are sold (as determined on a specific identification basis) or are other-than-temporarily impaired. If a decline in value of an investment below cost is deemed other than temporary, the cost of the investment is written down to fair value, with a corresponding charge to earnings. Factors considered in judging whether an impairment is other than temporary include: the financial condition, business prospects and creditworthiness of the issuer; the relative amount of the decline; the Company's ability and intent to hold the investment until the fair value recovers; and the length of time that fair value has been less than cost. Impairment losses on equity securities are charged to earnings. With respect to an investment in a debt security, any resulting impairment loss is recognized in earnings if the Company intends to sell, or expects to be required to sell, the debt security before its amortized cost is recovered. If the Company does not expect to ultimately recover the amortized cost basis even if it does not intend to sell the security, the credit loss component is recognized in earnings and any difference between fair value and the amortized cost basis, net of the credit loss, is reflected in OCI. For regulated investments, any impairment charge is offset by the establishment of a regulatory asset to the extent recovery in regulated rates is probable.

Allowance for Doubtful Accounts

Trade receivables are stated at the outstanding principal amount, net of an estimated allowance for doubtful accounts. The allowance for doubtful accounts is based on the Company's assessment of the collectibility of amounts owed to the Company by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. As of December 31, 2016 and 2015, the allowance for doubtful accounts totaled $33 million and $31 million, respectively, and is included in trade receivables, net on the Consolidated Balance Sheets.

Derivatives

The Company employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage its commodity price, interest rate, and foreign currency exchange rate risk. Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting permitted under master netting agreements with counterparties and cash collateral paid or received under such agreements. Cash collateral received from or paid to counterparties to secure derivative contract assets or liabilities in excess of amounts offset is included in other current assets on the Consolidated Balance Sheets.

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

For the Company's derivatives not designated as hedging contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as regulatory assets and liabilities. For the Company's derivatives not designated as hedging contracts and for which changes in fair value are not recorded as regulatory assets and liabilities, unrealized gains and losses are recognized on the Consolidated Statements of Operations as operating revenue for sales contracts; cost of sales and operating expense for purchase contracts and electricity, natural gas and fuel swap contracts; and other, net for interest rate swap derivatives.

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

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

Inventories

Inventories consist mainly of fuel, which includes coal stocks, stored gas and fuel oil, totaling $402 million and $353 million as of December 31, 2016 and 2015, respectively, and materials and supplies totaling $523 million and $529 million as of December 31, 2016 and 2015, respectively. The cost of materials and supplies, coal stocks and fuel oil is determined primarily using the average cost method. The cost of stored gas is determined using either the last-in-first-out ("LIFO") method or the lower of average cost or market. With respect to inventories carried at LIFO cost, the replacement cost would be $27 million and $8 million higher as of December 31, 2016 and 2015, respectively.

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. The Company capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include capitalized interest, including debt allowance for funds used during construction ("AFUDC"), and equity AFUDC, as applicable to the Regulated Businesses. The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed. Additionally, MidAmerican Energy has regulatory arrangements in Iowa in which the carrying cost of certain utility plant has been reduced for amounts associated with electric returns on equity exceeding specified thresholds.

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

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

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of regulated facilities, is capitalized by the Regulated Businesses as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. AFUDC is computed based on guidelines set forth by the Federal Energy Regulatory Commission ("FERC") and the Alberta Utilities Commission ("AUC"). After construction is completed, the Company is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets.

Asset Retirement Obligations

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

Impairment

The Company evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. The impacts of regulation are considered when evaluating the carrying value of regulated assets.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired in business combinations. The Company evaluates goodwill for impairment at least annually and completed its annual review as of October 31. When evaluating goodwill for impairment, the Company estimates the fair value of the reporting unit. If the carrying amount of a reporting unit, including goodwill, exceeds the estimated fair value, then the identifiable assets, including identifiable intangible assets, and liabilities of the reporting unit are estimated at fair value as of the current testing date. The excess of the estimated fair value of the reporting unit over the current estimated fair value of net assets establishes the implied value of goodwill. The excess of the recorded goodwill over the implied goodwill value is charged to earnings as an impairment loss. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. The Company uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings; and an appropriate discount rate. In estimating future cash flows, the Company incorporates current market information, as well as historical factors. As such, the determination of fair value incorporates significant unobservable inputs. During 2016, 2015 and 2014, the Company did not record any goodwill impairments.

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

Revenue Recognition

Energy Businesses

Revenue from energy business customers is recognized as electricity or natural gas is delivered or services are provided. Revenue recognized includes billed and unbilled amounts. As of December 31, 2016 and 2015, unbilled revenue was $643 million and $660 million, respectively, and is included in trade receivables, net on the Consolidated Balance Sheets. Rates for energy businesses are established by regulators or contractual arrangements. When preliminary regulated rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued. The Company records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Consolidated Statements of Operations.

Real Estate Commission Revenue, Mortgage Revenue and Franchise Royalty Fees

Commission revenue from real estate brokerage transactions and related amounts due to agents are recognized when a real estate transaction is closed. Title and escrow closing fee revenue from real estate transactions and related amounts due to the title insurer are recognized at closing. Mortgage fee revenue consists of amounts earned related to application and underwriting fees, and fees on canceled loans. Fees associated with the origination and acquisition of mortgage loans are recognized as earned. Franchise royalty fees are based on a percentage of commissions earned by franchisees on real estate sales and are recognized when the sale closes.

Unamortized Debt Premiums, Discounts and Debt Issuance Costs

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

Foreign Currency

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

Income Taxes

Berkshire Hathaway includes the Company in its United States federal income tax return. The Company's provision for income taxes has been computed on a stand-alone basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using estimated income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities that are associated with components of OCI are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities that are associated with income tax benefits and expense for certain property-related basis differences and other various differences that PacifiCorp, MidAmerican Energy, Nevada Power and Sierra Pacific (the "Utilities") are required to pass on to their customers in most state jurisdictions are charged or credited directly to a regulatory asset or liability. As of December 31, 2016 and 2015, these amounts were recognized as regulatory assets of $1.6 billion and $1.5 billion, respectively, and regulatory liabilities of $25 million and $29 million, respectively, and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized. Investment tax credits are generally deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory jurisdictions.

The Company has not established deferred income taxes on the undistributed foreign earnings of Northern Powergrid or AltaLink or the related currency translation adjustment that have been determined by management to be reinvested indefinitely. The cumulative undistributed foreign earnings were approximately $3.0 billion as of December 31, 2016. The Company periodically evaluates its capital requirements. If circumstances change in the future and a portion of Northern Powergrid's or AltaLink's undistributed earnings were repatriated, the dividends would be subject to taxation in the United States. However, any United States income tax liability would be offset, in part, by available United States income tax credits with respect to corporate income taxes previously paid in the United Kingdom and Canada. Because of the availability of foreign income tax credits, it is not practicable to determine the United States income tax liability that would be recognized if such cumulative earnings were not reinvested indefinitely. The Company has established deferred income taxes on all other undistributed foreign earnings. If opportunities become available to repatriate any available cash without triggering incremental United States income tax expense, the Company may distribute certain foreign earnings of Northern Powergrid and AltaLink.

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

New Accounting Pronouncements

In November 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-18, which amends FASB Accounting Standards Codification ("ASC") Subtopic 230-10, “Statement of Cash Flows - Overall.” The amendments in this guidance require that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. 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 August 2016, the FASB issued ASU No. 2016-15, which amends FASB ASC Topic 230, "Statement of Cash Flows." The amendments in this guidance address the classification of eight specific cash flow issues within the statement of cash flows with the objective of reducing the existing diversity in practice. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. The Company is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements.

In February 2016, the FASB issued ASU No. 2016-02, which creates FASB ASC Topic 842, "Leases" and supersedes Topic 840 "Leases." This guidance increases transparency and comparability among entities by recording lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. A lessee should recognize in the balance sheet a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from previous guidance. This guidance is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted, and is required to be adopted using a modified retrospective approach. 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 2016, the FASB issued ASU No. 2016-01, which amends FASB ASC Subtopic 825-10, "Financial Instruments - Overall." The amendments in this guidance address certain aspects of recognition, measurement, presentation and disclosure of financial instruments including a requirement that all investments in equity securities that do not qualify for equity method accounting or result in consolidation of the investee be measured at fair value with changes in fair value recognized in net income. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption not permitted, and is required to be adopted prospectively by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. 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. The material impacts currently identified include recording the unrealized gains and losses on available-for-sale securities in the Consolidated Statements of Operations as opposed to OCI. For the years ended December 31, 2016, 2015 and 2014, these amounts, net of tax, were $(30) million, $225 million and $(134) million, respectively.

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. During 2016, the FASB issued several ASUs that clarify the implementation guidance for ASU No. 2014-09 but do not change the core principle of the guidance. 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. The Company currently does not expect the timing and amount of revenue currently recognized to be materially different after adoption of the new guidance as a majority of revenue is recognized when the Company has the right to invoice as it corresponds directly with the value to the customer of the Company’s performance to date. The Company's current plan is to quantitatively disaggregate revenue in the required financial statement footnote by regulated energy, nonregulated energy and real estate, with further disaggregation of regulated energy by jurisdiction and real estate by line of business.

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

BHE owns a highly diversified portfolio of businesses comprised primarily of regulated utilities. Consistent with BHE's strategy to grow and further diversify through a disciplined acquisition approach, the Company closed on several acquisitions during 2016, 2015 and 2014.

AltaLink

Transaction Description

On December 1, 2014, BHE completed its acquisition of AltaLink and AltaLink became an indirect wholly owned subsidiary of BHE ("AltaLink Transaction"). Under the terms of the Share Purchase Agreement, dated May 1, 2014, among 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 8,200 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").

Included in BHE's Consolidated Statement of Operations within the BHE Transmission reportable segment for the year ended December 31, 2014 is $13 million of net income as a result of including AltaLink's revenue and expenses from December 1, 2014. Additionally, BHE incurred $3 million of direct transaction costs associated with the AltaLink Transaction that are included in operating expense on the Consolidated Statement of Operations for the year ended December 31, 2014.

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):

	2014
Operating revenue	17,888
Net income attributable to BHE shareholders	2,155

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.

Other

In 2016, the Company completed various other acquisitions totaling $66 million. The purchase prices were allocated to the assets acquired and liabilities assumed in each acquisition. The assets acquired consisted of property, plant and equipment, development and construction costs for renewable projects, other working capital items, goodwill of $50 million and other identifiable intangible assets. The liabilities assumed totaled $54 million.

In 2015, the Company completed various other acquisitions totaling $164 million. The purchase prices were allocated to the assets acquired and liabilities assumed in each acquisition. The assets acquired consisted of property, plant and equipment, development and construction costs for renewable projects, other working capital items, goodwill of $33 million and other identifiable intangible assets. The liabilities assumed totaled $84 million.

In 2014, the Company completed various other acquisitions totaling $243 million. The purchase price for each acquisition was allocated to the assets acquired and liabilities assumed, which related primarily to property, plant and equipment of $641 million, goodwill of $80 million, long-term debt of $231 million and noncurrent deferred income tax liabilities of $170 million for the remaining 50% interest in CE Generation, LLC ("CE Generation"), development and construction costs for the 300-megawatt ("MW") TX Jumbo Road Wind, LLC wind-powered generation project ("Jumbo Road Project") and real estate brokerage and mortgage businesses. There were no other material assets acquired or liabilities assumed.

(4) Property, Plant and Equipment, Net

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

	Depreciable Life	2016	2015
Regulated assets:			
Utility generation, transmission and distribution systems	5-80 years	$ 71,536	$ 69,248
Interstate natural gas pipeline assets	3-80 years	6,942	6,755
		78,478	76,003
Accumulated depreciation and amortization		(23,603)	(22,682)
Regulated assets, net		54,875	53,321
Nonregulated assets:			
Independent power plants	5-30 years	5,594	4,751
Other assets	3-30 years	1,002	875
		6,596	5,626
Accumulated depreciation and amortization		(1,060)	(805)
Nonregulated assets, net		5,536	4,821
Net operating assets		60,411	58,142
Construction work-in-progress		2,098	2,627
Property, plant and equipment, net		$ 62,509	$ 60,769

Construction work-in-progress includes $1.8 billion and $2.3 billion as of December 31, 2016 and 2015, respectively, related to the construction of regulated assets.

During the fourth quarter of 2016, MidAmerican Energy revised its electric and gas depreciation rates based on the results of a new depreciation study, the most significant impact of which was longer estimated useful lives for certain wind-powered generating facilities. The effect of this change was to reduce depreciation and amortization expense by $3 million in 2016 and $34 million annually based on depreciable plant balances at the time of the change.

(5) Jointly Owned Utility Facilities

Under joint facility ownership agreements, the Domestic Regulated Businesses, as tenants in common, have undivided interests in jointly owned generation, transmission, distribution and pipeline common facilities. The Company accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Consolidated Statements of Operations include the Company's share of the expenses of these facilities.

The amounts shown in the table below represent the Company's share in each jointly owned facility as of December 31, 2016 (dollars in millions):

	Company Share	Facility In Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
PacifiCorp:				
Jim Bridger Nos. 1-4	67%	$ 1,420	$ 583	$ 10
Hunter No. 1	94	473	161	1
Hunter No. 2	60	296	98	—
Wyodak	80	467	203	1
Colstrip Nos. 3 and 4	10	244	130	5
Hermiston	50	178	76	2
Craig Nos. 1 and 2	19	325	223	32
Hayden No. 1	25	74	32	—
Hayden No. 2	13	43	20	—
Foote Creek	79	39	25	—
Transmission and distribution facilities	Various	777	228	61
Total PacifiCorp		4,336	1,779	112
MidAmerican Energy:				
Louisa No. 1	88%	766	418	9
Quad Cities Nos. 1 and 2(1)	25	689	367	7
Walter Scott, Jr. No. 3	79	614	303	1
Walter Scott, Jr. No. 4(2)	60	448	101	2
George Neal No. 4	41	307	154	1
Ottumwa No. 1	52	548	191	13
George Neal No. 3	72	426	174	1
Transmission facilities	Various	247	86	1
Total MidAmerican Energy		4,045	1,794	35
NV Energy:				
Navajo	11%	213	145	2
Silverhawk	75	248	66	3
Valmy	50	389	216	1
Transmission facilities	Various	213	41	—
Total NV Energy		1,063	468	6
BHE Pipeline Group - common facilities	Various	286	164	—
Total		$ 9,730	$ 4,205	$ 153

(1) Includes amounts related to nuclear fuel.

(2) Facility in-service and accumulated depreciation and amortization amounts are net of credits applied under Iowa revenue sharing arrangements totaling $319 million and $75 million, respectively.

(6) Regulatory Matters

Regulatory Assets

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

	Weighted Average Remaining Life	2016	2015
Deferred income taxes[1]	27 years	$ 1,754	$ 1,577
Employee benefit plans[2]	17 years	816	778
Asset disposition costs	Various	281	307
Deferred net power costs	1 year	38	140
Asset retirement obligations	12 years	301	281
Unrealized loss on regulated derivative contracts	5 years	154	250
Abandoned projects	3 years	159	136
Unamortized contract values	7 years	98	110
Other	Various	856	706
Total regulatory assets		$ 4,457	$ 4,285
Reflected as:			
Current assets		$ 150	$ 130
Noncurrent assets		4,307	4,155
Total regulatory assets		$ 4,457	$ 4,285

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

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

The Company had regulatory assets not earning a return on investment of $2.8 billion and $2.3 billion as of December 31, 2016 and 2015, respectively.

Regulatory Liabilities

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

	Weighted Average Remaining Life	2016	2015
Cost of removal[(1)]	27 years	$ 2,242	$ 2,167
Deferred net power costs	1 years	64	206
Asset retirement obligations	35 years	122	147
Levelized depreciation	23 years	244	199
Impact fees	6 years	90	—
Employee benefit plans[(2)]	12 years	25	13
Unrealized gain on regulated derivative contracts	1 year	6	—
Other	Various	327	301
Total regulatory liabilities		$ 3,120	$ 3,033
Reflected as:			
Current liabilities		$ 187	$ 402
Noncurrent liabilities		2,933	2,631
Total regulatory liabilities		$ 3,120	$ 3,033

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

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

ALP General Tariff Application ("GTA")

In November 2014, ALP filed a GTA requesting the Alberta Utilities Commission ("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 Alberta Electric System Operator. ALP amended the GTA in June 2015 to propose transmission tariff relief measures for customers and modifications to its capital structure. ALP also amended and updated the GTA in October 2015, reducing the requested revenue requirements to C$672 million for 2015 and C$704 million for 2016. In May 2016, the AUC issued its decision pertaining to the 2015-2016 GTA. ALP filed its 2015-2016 GTA compliance filing in July 2016 to comply with the AUC's decision.

The compliance filing requested the AUC to approve revenue requirements of C$599 million for 2015 and C$685 million for 2016. The decreased revenue requirements requested in the compliance filing, as compared to the 2015-2016 GTA filing updated in October 2015, were primarily due to the AUC approval of ALP's proposed immediate tariff relief of C$415 million for customers for 2015 and 2016, through (i) the discontinuance of construction work-in-progress ("CWIP") in rate base and the return to allowance for funds used during construction ("AFUDC") accounting effective January 1, 2015, resulting in a C$82 million reduction of revenue requirement and the refund of C$277 million previously collected as CWIP in rate base as part of ALP's transmission tariffs during 2011-2014 less related returns of C$12 million and (ii) a change to the flow through method for calculating income taxes for 2016, resulting in further tariff relief of C$68 million.

Operating revenue for the year ended December 31, 2016, included a one-time reduction of $200 million from the 2015-2016 GTA decision received in May 2016 at ALP. The 2015-2016 GTA decision required ALP to refund $200 million to customers in 2016 through reduced monthly billings for the change from receiving cash during construction for the return on CWIP in rate base to recording allowance for borrowed and equity funds used during construction related to construction expenditures during the 2011 to 2014 time period. This amount is offset with higher capitalized interest and allowance for equity funds in the Consolidated Statements of Operations. In addition, the decision required ALP to change to the flow through method of recognizing income tax expense effective January 1, 2016. This change reduced operating revenue by $45 million for the year ended December 31, 2016, with offsetting impacts to income tax expense in the Consolidated Statements of Operations.

(7) Investments and Restricted Cash and Investments

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

	2016	2015
Investments:		
BYD Company Limited common stock	$ 1,185	$ 1,238
Rabbi trusts	403	380
Other	106	130
Total investments	1,694	1,748
Equity method investments:		
Electric Transmission Texas, LLC	672	585
Bridger Coal Company	165	190
BHE Renewables tax equity investments	741	168
Other	142	160
Total equity method investments	1,720	1,103
Restricted cash and investments:		
Quad Cities Station nuclear decommissioning trust funds	460	429
Solar Star and Topaz Projects	64	95
Other	218	129
Total restricted cash and investments	742	653
Total investments and restricted cash and investments	$ 4,156	$ 3,504
Reflected as:		
Current assets	$ 211	$ 137
Noncurrent assets	3,945	3,367
Total investments and restricted cash and investments	$ 4,156	$ 3,504

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 AOCI. The fair value of BHE's investment in BYD Company Limited common stock reflects a pre-tax unrealized gain of $953 million and $1,006 million as of December 31, 2016 and 2015, respectively.

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

Equity Method Investments

BHE, through a subsidiary, owns 50% of Electric Transmission Texas, LLC, which owns and operates electric transmission assets in the Electric Reliability Council of Texas footprint. BHE, through a subsidiary, owns 66.67% of Bridger Coal Company ("Bridger Coal"), which is a coal mining joint venture that supplies coal to the Jim Bridger generating facility. Bridger Coal is being accounted for under the equity method of accounting as the power to direct the activities that most significantly impact Bridger Coal's economic performance are shared with the joint venture partner.

The Company has also invested in projects sponsored by third parties, commonly referred to as tax equity investments. Under the terms of these tax equity investments, the Company has entered into equity capital contribution agreements with the project sponsors that require contributions. The Company has made contributions of $170 million in 2015 and $584 million in 2016 pursuant to these equity capital contribution agreements as the various projects achieve commercial operation. Once a project achieves commercial operation, the Company enters into a partnership agreement with the project sponsor that directs and allocates the operating profits and tax benefits from the project.

Restricted Cash and Investments

MidAmerican Energy has established a trust for the investment of funds for decommissioning the Quad Cities Nuclear Station Units 1 and 2 ("Quad Cities Station"). These investments in debt and equity securities are classified as available-for-sale and are reported at fair value. Funds are invested in the trust in accordance with applicable federal and state investment guidelines and are restricted for use as reimbursement for costs of decommissioning the Quad Cities Station, which are currently licensed for operation until December 2032.

(8) Short-Term Debt and Credit Facilities

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

	BHE	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	AltaLink	Other	Total[1]
2016:								
Credit facilities	$ 2,000	$ 1,000	$ 609	$ 650	$ 185	$ 986	$ 915	$ 6,345
Less:								
Short-term debt	(834)	(270)	(99)	—	—	(289)	(377)	(1,869)
Tax-exempt bond support and letters of credit	(7)	(142)	(220)	(80)	—	(8)	—	(457)
Net credit facilities	$ 1,159	$ 588	$ 290	$ 570	$ 185	$ 689	$ 538	$ 4,019
2015:								
Credit facilities	$ 2,000	$ 1,200	$ 609	$ 650	$ 221	$ 813	$ 928	$ 6,421
Less:								
Short-term debt	(253)	(20)	—	—	—	(401)	(300)	(974)
Tax-exempt bond support and letters of credit	(51)	(160)	(195)	—	—	(9)	—	(415)
Net credit facilities	$ 1,696	$ 1,020	$ 414	$ 650	$ 221	$ 403	$ 628	$ 5,032

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

As of December 31, 2016, the Company was in compliance with the covenants of its credit facilities and letter of credit arrangements.

BHE

BHE has a $2.0 billion unsecured credit facility expiring in June 2019 with two one-year extension options subject to bank consent. The credit facility, which is for general corporate purposes and also supports BHE's commercial paper program and provides for the issuance of letters of credit, has a variable interest rate based on the LIBOR or a base rate, at BHE's option, plus a spread that varies based on BHE's senior unsecured long-term debt credit ratings. As of December 31, 2016 and 2015, the weighted average interest rate on commercial paper borrowings outstanding was 0.88% and 0.66%, respectively. The credit facility requires that BHE's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.70 to 1.0 as of the last day of each quarter.

As of December 31, 2016 and 2015, BHE had $123 million and $142 million, respectively, of letters of credit outstanding, of which $7 million and $51 million as of December 31, 2016 and 2015 were issued under the credit facilities. These letters of credit primarily support power purchase agreements and debt service requirements at certain subsidiaries of BHE Renewables, LLC and expire through December 2018.

PacifiCorp

PacifiCorp has a $600 million unsecured credit facility expiring in March 2018 and a $400 million unsecured credit facility expiring in June 2019 each with two one-year extension options subject to bank consent. These credit facilities, which support PacifiCorp's commercial paper program, certain series of its tax-exempt bond obligations and provide for the issuance of letters of credit, have a variable interest rate based on LIBOR or a base rate, at PacifiCorp's option, plus a spread that varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities. As of December 31, 2016 and 2015, the weighted average interest rate on commercial paper borrowings outstanding was 0.96% and 0.65%, respectively. These credit facilities require that PacifiCorp's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter.

As of December 31, 2016 and 2015, PacifiCorp had $255 million and $310 million, respectively, of fully available letters of credit issued under committed arrangements, of which $10 million as of December 31, 2015 were issued under the credit facilities. These letters of credit support PacifiCorp's variable-rate tax-exempt bond obligations and expire through March 2019.

MidAmerican Funding

MidAmerican Energy has a $600 million unsecured credit facility expiring in March 2018 with two one-year extension options subject to bank consent. The credit facility, which supports MidAmerican Energy's commercial paper program and its variable-rate tax-exempt bond obligations and provides for the issuance of letters of credit, has a variable interest rate based on LIBOR or a base rate, at MidAmerican Energy's option, plus a spread that varies based on MidAmerican Energy's credit ratings for senior unsecured long-term debt securities. As of December 31, 2016, the weighted average interest rate on commercial paper borrowings outstanding was 0.73%. The credit facility requires that MidAmerican Energy's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter.

NV Energy

Nevada Power has a $400 million secured credit facility expiring in March 2018 and Sierra Pacific has a $250 million secured credit facility expiring in March 2018 each with two one-year extension options subject to bank consent. These credit facilities, which are for general corporate purposes and provide for the issuance of letters of credit, have a variable interest rate based on LIBOR or a base rate, at each of the Nevada Utilities' option, plus a spread that varies based on each of the Nevada Utilities' credit ratings for its senior secured long-term debt securities. Amounts due under each credit facility are collateralized by each of the Nevada Utilities' general and refunding mortgage bonds. The credit facilities require that each of the Nevada Utilities' ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.68 to 1.0 as of the last day of each quarter.

Northern Powergrid

Northern Powergrid has a £150 million unsecured credit facility expiring in April 2020. The credit facility has a variable interest rate based on sterling LIBOR plus a spread that varies based on its credit ratings. The credit facility requires that the ratio of consolidated senior total net debt, including current maturities, to regulated asset value not exceed 0.8 to 1.0 at Northern Powergrid and 0.65 to 1.0 at Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc as of June 30 and December 31. Northern Powergrid's interest coverage ratio shall not be less than 2.5 to 1.0.

AltaLink

ALP has a C$750 million secured revolving credit facility expiring in December 2018 with a one-year extension option subject to bank consent. The credit facility, which provides support for borrowings under the unsecured commercial paper program and may also be used for general corporate purposes, has a variable interest rate based on the Canadian bank prime lending rate or a spread above the Bankers' Acceptance rate, at ALP's option, based on ALP's credit ratings for its senior secured long-term debt securities. In addition, ALP has a C$75 million secured revolving credit facility expiring in December 2018 with a one-year extension option subject to bank consent. The credit facility, which may be used for general corporate purposes, capital expenditures and letters of credit, has a variable interest rate based on the Canadian bank prime lending rate, United States base rate, United States LIBOR loan rate, or a spread above the Bankers' Acceptance rate, at ALP's option, based on ALP's credit ratings for its senior secured long-term debt securities. At the renewal date, ALP has the option to convert these facilities to one-year term facilities. The credit facilities require the consolidated indebtedness to total capitalization not exceed 0.75 to 1.0 measured as of the last day of each quarter. As of December 31, 2016 and 2015, ALP had $26 million and $324 million outstanding under these facilities at a weighted average interest rate of 0.99% and 0.94%, respectively.

AltaLink Investments, L.P. has a C$300 million unsecured revolving term credit facility expiring in December 2021 and a C$200 million unsecured revolving credit facility expiring in December 2017 each with a one-year extension option subject to bank consent. The credit facilities, which may be used for operating expenses, capital expenditures, working capital needs and letters of credit to a maximum of C$10 million, have a variable interest rate based on the Canadian bank prime lending rate, United States base rate, United States LIBOR loan rate, or a spread above the Bankers' Acceptance rate, at AltaLink Investments, L.P.'s option, based on AltaLink Investments, L.P.'s credit ratings for its senior unsecured long-term debt securities. The credit facilities require the consolidated total debt to capitalization to not exceed 0.8 to 1.0 and earnings before interest, taxes, depreciation and amortization to interest expense for the four fiscal quarters ended to not be less than 2.25 to 1.0 measured as of the last day of each quarter. As of December 31, 2016 and 2015, AltaLink Investments, L.P. had $263 million and $77 million outstanding under these facilities at a weighted average interest rate of 1.74% and 2.09%, respectively.

HomeServices

HomeServices has a $350 million unsecured credit facility expiring in July 2018. The credit facility has a variable interest rate based on the prime lending rate or the LIBOR, at HomeServices' option, plus a spread that varies based on HomeServices' Total Leverage Ratio as defined in the agreement. As of December 31, 2016, HomeServices had $50 million outstanding under its credit facility with a weighted average interest rate of 1.77%.

Through its subsidiaries, HomeServices maintains mortgage lines of credit totaling $565 million and $578 million as of December 31, 2016 and 2015, respectively, used for mortgage banking activities that expire beginning in February 2017 through December 2017 or are due on demand. The mortgage lines of credit have variable rates based on LIBOR plus a spread. Collateral for these credit facilities is comprised of residential property being financed and is equal to the loans funded with the facilities. As of December 31, 2016 and 2015, HomeServices had $327 million and $300 million, respectively, outstanding under these mortgage lines of credit at a weighted average interest rate of 2.77% and 2.42%, respectively.

BHE Renewables Letters of Credit

In connection with their bond offerings, Topaz and Solar Star entered into separate letter of credit and reimbursement facilities totaling $627 million. Letters of credit issued under the letter of credit facilities will be used to (a) provide security under the power purchase agreement and large generator interconnection agreements, (b) fund the debt service reserve requirement and the operation and maintenance debt service reserve requirement and (c) provide security for remediation and mitigation liabilities. As of December 31, 2016 and 2015, $599 million and $600 million, respectively, of letters of credit had been issued under these facilities.

As of December 31, 2016 and 2015, certain renewable projects collectively have letters of credit outstanding of $106 million and $65 million, respectively, primarily in support of the power purchase agreements associated with the projects.

(9) BHE Debt

Senior Debt

BHE senior debt represents unsecured senior obligations of BHE that are redeemable in whole or in part at any time generally with make-whole premiums. BHE senior debt consists of the following, including unamortized premiums, discounts and debt issuance costs, as of December 31 (in millions):

	Par Value	2016	2015
1.10% Senior Notes, due 2017	$ 400	$ 400	$ 399
5.75% Senior Notes, due 2018	650	649	648
2.00% Senior Notes, due 2018	350	349	348
2.40% Senior Notes, due 2020	350	349	348
3.75% Senior Notes, due 2023	500	497	497
3.50% Senior Notes, due 2025	400	397	397
8.48% Senior Notes, due 2028	475	477	477
6.125% Senior Bonds, due 2036	1,700	1,690	1,690
5.95% Senior Bonds, due 2037	550	547	547
6.50% Senior Bonds, due 2037	1,000	987	987
5.15% Senior Notes, due 2043	750	739	739
4.50% Senior Notes, due 2045	750	737	737
Total BHE Senior Debt	$ 7,875	$ 7,818	$ 7,814

	2016	2015
Reflected as:		
Current liabilities	$ 400	$ —
Noncurrent liabilities	7,418	7,814
Total BHE Senior Debt	$ 7,818	$ 7,814

Junior Subordinated Debentures

BHE junior subordinated debentures consists of the following as of December 31 (in millions):

	Par Value	2016	2015
Junior subordinated debentures, due 2043	$ —	$ —	$ 1,444
Junior subordinated debentures, due 2044	944	944	1,500
Total BHE junior subordinated debentures - noncurrent	$ 944	$ 944	$ 2,944

BHE issued junior subordinated debentures to certain subsidiaries of Berkshire Hathaway pursuant to an indenture, by and between BHE and The Bank of New York Mellon Trust Company, N.A., as trustee, dated as of December 19, 2013 and November 12, 2014. The junior subordinated debentures are unsecured and junior in right of payment to BHE's senior debt. The junior subordinated debentures (i) have a 30 year maturity; (ii) bear interest at a floating rate equal to (a) the greater of 1% and the LIBOR (the greater of such two rates, the "Base Rate") plus 200 basis points through the date prior to the third anniversary of the issuance date; (b) the Base Rate plus 300 basis points (or, if at least 50% of principal is repaid prior to the third anniversary of the issuance date, the Base Rate plus 200 basis points) from the third anniversary of the issuance date through the date prior to the seventh anniversary of the issuance date; and (c) the Base Rate plus 375 basis points from the seventh anniversary of the issuance date until the maturity of the junior subordinated debentures; and (iii) are redeemable at BHE's option from time to time at par plus accrued and unpaid interest. The holders are restricted from transferring the junior subordinated debentures except to Berkshire Hathaway and its subsidiaries. As of December 31, 2016 and 2015, the interest rate was 3.0%. Interest expense to Berkshire Hathaway for the years ended December 31, 2016, 2015 and 2014 was $65 million, $104 million and $78 million, respectively.

In February 2017, BHE provided notice of redemption for $200 million of the junior subordinated debentures due 2044 at par value to occur in March 2017.

(10) Subsidiary Debt

BHE's direct and indirect subsidiaries are organized as legal entities separate and apart from BHE and its other subsidiaries. Pursuant to separate financing agreements, substantially all of PacifiCorp's electric utility properties; the equity interest of MidAmerican Funding's subsidiary; MidAmerican Energy's electric utility properties in the state of Iowa; substantially all of Nevada Power's and Sierra Pacific's properties in the state of Nevada; the long-term customer contracts of Kern River; AltaLink's transmission properties; and substantially all of the assets of the subsidiaries of BHE Renewables are pledged or encumbered to support or otherwise provide the security for their related subsidiary debt. 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 which are available for distribution may, subject to applicable law, regulatory commitments and the terms of financing and ring-fencing arrangements for such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to BHE or affiliates thereof. The long-term debt of subsidiaries may include provisions that allow BHE's subsidiaries to redeem it in whole or in part at any time. These provisions generally include make-whole premiums.

Distributions at these separate legal entities are limited by various covenants including, among others, leverage ratios, interest coverage ratios and debt service coverage ratios. As of December 31, 2016, all subsidiaries were in compliance with their long-term debt covenants.

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

	Par Value	2016	2015
PacifiCorp	$ 7,120	$ 7,079	$ 7,159
MidAmerican Funding	4,657	4,592	4,560
NV Energy	4,569	4,582	4,860
Northern Powergrid	2,351	2,379	2,772
BHE Pipeline Group	995	990	1,040
BHE Transmission	4,068	4,058	3,467
BHE Renewables	3,716	3,674	3,356
Total subsidiary debt	$ 27,476	$ 27,354	$ 27,214
Reflected as:			
Current liabilities		$ 606	$ 1,148
Noncurrent liabilities		26,748	26,066
Total subsidiary debt		$ 27,354	$ 27,214

PacifiCorp

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

	Par Value	2016	2015
First mortgage bonds:			
3.85% to 8.53%, due through 2021	$ 1,272	$ 1,269	$ 1,271
2.95% to 8.27%, due 2022 to 2026	1,829	1,820	1,819
7.70% due 2031	300	298	298
5.25% to 6.10%, due 2034 to 2036	850	843	843
5.75% to 6.35%, due 2037 to 2039	2,150	2,134	2,133
4.10% due 2042	300	297	297
Variable-rate series, tax-exempt bond obligations (2016-0.69% to 0.86%; 2015-0.01% to 0.22%):			
Due 2017 to 2018	91	91	91
Due 2018 to 2025[(1)]	108	108	107
Due 2024[(1)(2)]	143	142	196
Due 2024 to 2025[(2)]	50	50	59
Capital lease obligations - 8.75% to 14.61%, due through 2035	27	27	45
Total PacifiCorp	$ 7,120	$ 7,079	$ 7,159

(1) Supported by $255 million and $310 million of fully available letters of credit issued under committed bank arrangements as of December 31, 2016 and 2015, respectively.

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

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $26 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2016.

MidAmerican Funding

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

	Par Value	2016	2015
MidAmerican Funding:			
6.927% Senior Bonds, due 2029	$ 325	$ 291	$ 289
MidAmerican Energy:			
Tax-exempt bond obligations -			
Variable-rate tax-exempt bond obligation series: (2016-0.76%, 2015-0.03%), due 2023-2046	220	219	194
First Mortgage Bonds:			
2.40%, due 2019	500	499	499
3.70%, due 2023	250	248	248
3.50%, due 2024	500	501	502
4.80%, due 2043	350	345	345
4.40%, due 2044	400	394	394
4.25%, due 2046	450	445	444
Notes:			
5.95% Series, due 2017	250	250	250
5.3% Series, due 2018	350	350	349
6.75% Series, due 2031	400	396	395
5.75% Series, due 2035	300	298	298
5.8% Series, due 2036	350	347	347
Transmission upgrade obligation, 4.45% and 3.42% due through 2035 and 2036, respectively	10	7	4
Capital lease obligations - 4.16%, due through 2020	2	2	2
Total MidAmerican Energy	4,332	4,301	4,271
Total MidAmerican Funding	$ 4,657	$ 4,592	$ 4,560

In February 2017, MidAmerican Energy issued $375 million of its 3.10% First Mortgage Bonds due May 2027 and $475 million of its 3.95% First Mortgage Bonds due August 2047. An amount equal to the net proceeds will be used to finance capital expenditures, disbursed during the period from February 2, 2016 to February 1, 2017, with respect to investments in MidAmerican Energy's 551-megawatt Wind X and 2,000-megawatt Wind XI projects, which were previously financed with MidAmerican Energy's general funds.

In January 2017, MidAmerican Energy provided notice to holders of its $250 million of 5.95% Senior Notes due July 2017 that MidAmerican Energy would redeem such notes in full through optional redemption on February 27, 2017.

Pursuant to MidAmerican Energy's mortgage dated September 9, 2013, MidAmerican Energy's first mortgage bonds, currently and from time to time outstanding, are secured by a first mortgage lien on substantially all of its electric generating, transmission and distribution property within the state of Iowa, subject to certain exceptions and permitted encumbrances. As of December 31, 2016, MidAmerican Energy's eligible property subject to the lien of the mortgage totaled approximately $15 billion based on original cost. Additionally, MidAmerican Energy's senior notes outstanding are equally and ratably secured with the first mortgage bonds as required by the indentures under which the senior notes were issued.

NV Energy

NV Energy's long-term debt consists of the following, including fair value adjustments and unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2016	2015
NV Energy -			
6.250% Senior Notes, due 2020	$ 315	$ 363	$ 373
Nevada Power:			
General and refunding mortgage securities:			
5.950% Series M, due 2016	—	—	210
6.500% Series O, due 2018	324	324	323
6.500% Series S, due 2018	499	498	498
7.125% Series V, due 2019	500	499	499
6.650% Series N, due 2036	367	357	356
6.750% Series R, due 2037	349	345	345
5.375% Series X, due 2040	250	247	247
5.450% Series Y, due 2041	250	236	235
Variable-rate series (2016-1.890% to 1.928%, 2015-0.672% to 1.055%):			
Pollution Control Revenue Bonds Series 2006A, due 2032	38	38	38
Pollution Control Revenue Bonds Series 2006, due 2036	38	37	37
Capital and financial lease obligations - 2.750% to 11.600%, due through 2054	485	485	497
Total Nevada Power	3,100	3,066	3,285
Sierra Pacific:			
General and refunding mortgage securities:			
6.000% Series M, due 2016	—	—	450
3.375% Series T, due 2023	250	248	248
2.600% Series U, due 2026	400	395	—
6.750% Series P, due 2037	252	255	255
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
1.250% Pollution Control Series 2016A, due 2029	20	20	—
1.500% Gas Facilities Series 2016A, due 2031	58	58	—
3.000% Gas and Water Series 2016B, due 2036	60	64	—
Variable-rate series (2016-0.788% to 0.800%, 2015-0.733% to 1.054%):			
Pollution Control Series 2006A, due 2031	—	—	58
Pollution Control Series 2006B, due 2036	—	—	74
Pollution Control Series 2006C, due 2036	—	—	80
Water Facilities Series 2016C, due 2036	30	29	—
Water Facilities Series 2016D, due 2036	25	25	—
Water Facilities Series 2016E, due 2036	25	25	—
Capital and financial lease obligations - 2.700% to 10.130%, due through 2054	34	34	37
Total Sierra Pacific	1,154	1,153	1,202
Total NV Energy	$ 4,569	$ 4,582	$ 4,860

The issuance of General and Refunding Mortgage Securities by the Nevada Utilities is subject to PUCN approval and is limited by available property and other provisions of the mortgage indentures for each of Nevada Power and Sierra Pacific. As of December 31, 2016, approximately $8.9 billion of Nevada Power's and $3.8 billion of Sierra Pacific's (based on original cost) property was subject to the liens of the mortgages.

Northern Powergrid

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

	Par Value[(1)]	2016	2015
8.875% Bonds, due 2020	$ 123	$ 136	$ 162
9.25% Bonds, due 2020	247	259	315
3.901% to 4.586% European Investment Bank loans, due 2018 to 2022	333	333	398
7.25% Bonds, due 2022	247	257	306
2.50% Bonds due 2025	185	182	217
2.073% European Investment Bank loan, due 2025	62	62	—
2.564% European Investment Bank loans, due 2027	308	308	368
7.25% Bonds, due 2028	229	234	280
4.375% Bonds, due 2032	185	182	217
5.125% Bonds, due 2035	247	243	291
5.125% Bonds, due 2035	185	183	218
Total Northern Powergrid	$ 2,351	$ 2,379	$ 2,772

(1) The par values for these debt instruments are denominated in sterling.

BHE Pipeline Group

BHE Pipeline Group' long-term debt consists of the following, including unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2016	2015
Northern Natural Gas:			
5.75% Senior Notes, due 2018	$ 200	$ 199	$ 199
4.25% Senior Notes, due 2021	200	199	199
5.8% Senior Bonds, due 2037	150	149	149
4.1% Senior Bonds, due 2042	250	248	248
Total Northern Natural Gas	800	795	795
Kern River:			
4.893% Senior Notes, due 2018	195	195	245
Total BHE Pipeline Group	$ 995	$ 990	$ 1,040

Kern River's long-term debt amortizes monthly. Kern River redeemed the remaining amount of its 6.676% Senior Notes due 2016 at a redemption price determined in accordance with the terms of the indenture. Kern River provides a debt service reserve letter of credit to cover the next six months of principal and interest payments due on the loans, which were equal to $35 million and $33 million as of December 31, 2016 and 2015, respectively.

BHE Transmission

BHE Transmission's long-term debt consists of the following, including fair value adjustments and unamortized premiums, discounts and debt issuance costs, as of December 31, (dollars in millions):

	Par Value[1]	2016	2015
AltaLink Investments, L.P.:			
Series 09-1 Senior Bonds, 5.207%, due 2016	$ —	$ —	$ 112
Series 12-1 Senior Bonds, 3.674%, due 2019	149	153	151
Series 13-1 Senior Bonds, 3.265%, due 2020	149	152	149
Series 15-1 Senior Bonds, 2.244%, due 2022	149	148	144
Total AltaLink Investments, L.P.	447	453	556
AltaLink, L.P.:			
Series 2008-1 Notes, 5.243%, due 2018	149	148	145
Series 2013-2 Notes, 3.621%, due 2020	93	93	90
Series 2012-2 Notes, 2.978%, due 2022	204	204	198
Series 2013-4 Notes, 3.668%, due 2023	372	371	360
Series 2014-1 Notes, 3.399%, due 2024	260	260	252
Series 2016-1 Notes, 2.747%, due 2026	260	259	—
Series 2006-1 Notes, 5.249%, due 2036	112	111	108
Series 2010-1 Notes, 5.381%, due 2040	93	93	90
Series 2010-2 Notes, 4.872%, due 2040	112	111	108
Series 2011-1 Notes, 4.462%, due 2041	205	204	198
Series 2012-1 Notes, 3.99%, due 2042	391	385	374
Series 2013-3 Notes, 4.922%, due 2043	260	260	252
Series 2014-3 Notes, 4.054%, due 2044	219	218	212
Series 2015-1 Notes, 4.090%, due 2045	260	259	251
Series 2016-2 Notes, 3.717%, due 2046	335	333	—
Series 2013-1 Notes, 4.446%, due 2053	186	186	180
Series 2014-2 Notes, 4.274%, due 2064	97	97	93
Total AltaLink, L.P.	3,608	3,592	2,911
Other:			
Construction Loan, 4.950%, due 2021	13	13	—
Total BHE Transmission	$ 4,068	$ 4,058	$ 3,467

(1) The par values for these debt instruments are denominated in Canadian dollars.

BHE Renewables

BHE Renewables' long-term debt consists of the following, including fair value adjustments and unamortized debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2016	2015
Fixed-rate[1]:			
CE Generation Bonds, 7.416%, due 2018	$ 67	$ 67	$ 97
Salton Sea Funding Corporation Bonds, 7.475%, due 2018	30	31	51
Cordova Funding Corporation Bonds, 8.48% to 9.07%, due 2019	96	97	113
Bishop Hill Holdings Senior Notes, 5.125%, due 2032	100	99	102
Solar Star Funding Senior Notes, 3.950%, due 2035	316	311	321
Solar Star Funding Senior Notes, 5.375%, due 2035	977	966	988
Grande Prairie Wind Senior Notes, 3.860%, due 2037	419	414	—
Topaz Solar Farms Senior Notes, 5.750%, due 2039	791	780	815
Topaz Solar Farms Senior Notes, 4.875%, due 2039	230	229	239
Other	22	22	25
Variable-rate[1]:			
Pinyon Pines I and II Term Loans, due 2019[2]	356	355	378
Wailuku Special Purpose Revenue Bonds, 0.90%, due 2021	7	7	8
TX Jumbo Road Term Loan, due 2025[2]	212	206	219
Marshall Wind Term Loan, due 2026[2]	93	90	—
Total BHE Renewables	$ 3,716	$ 3,674	$ 3,356

(1) Amortizes quarterly or semiannually.

(2) The term loans have variable interest rates based on LIBOR plus a margin that varies during the terms of the agreements. The Company has entered into interest rate swaps that fix the interest rate on 75% of the Pinyon Pines outstanding debt and 100% of the TX Jumbo Road and Marshall Wind outstanding debt. The variable interest rate as of December 31, 2016 and 2015 was 2.62% and 2.23%, respectively, while the fixed interest rates ranged from 3.21% to 3.63% as of December 31, 2016, and 3.55% to 3.63% as of December 31, 2015.

Annual Repayments of Long-Term Debt

The annual repayments of BHE and subsidiary debt for the years beginning January 1, 2017 and thereafter, excluding fair value adjustments and unamortized premiums, discounts and debt issuance costs, are as follows (in millions):

	2017	2018	2019	2020	2021	2022 and Thereafter	Total
BHE senior notes	$ 400	$ 1,000	$ —	$ 350	$ —	$ 6,125	$ 7,875
BHE junior subordinated debentures	—	—	—	—	—	944	944
PacifiCorp	58	588	352	40	425	5,657	7,120
MidAmerican Funding	251	351	500	2	1	3,552	4,657
NV Energy	18	840	519	336	27	2,829	4,569
Northern Powergrid	—	49	49	418	—	1,835	2,351
BHE Pipeline Group	66	329	—	—	200	400	995
BHE Transmission	—	151	151	245	3	3,518	4,068
BHE Renewables	213	236	528	161	167	2,411	3,716
Totals	$ 1,006	$ 3,544	$ 2,099	$ 1,552	$ 823	$ 27,271	$ 36,295

(11) Income Taxes

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

	2016	2015	2014
Current:			
Federal	$ (743)	$ (929)	$ (1,872)
State	1	29	(3)
Foreign	55	84	129
	(687)	(816)	(1,746)
Deferred:			
Federal	1,164	1,310	2,296
State	(59)	(53)	37
Foreign	(7)	17	11
	1,098	1,274	2,344
Investment tax credits	(8)	(8)	(9)
Total	$ 403	$ 450	$ 589

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

	2016	2015	2014
Federal statutory income tax rate	35%	35%	35%
Income tax credits	(14)	(11)	(10)
State income tax, net of federal income tax benefit	(1)	(1)	1
Income tax effect of foreign income	(6)	(7)	(3)
Equity income	2	2	2
Other, net	(2)	(2)	(2)
Effective income tax rate	14%	16%	23%

Income tax credits relate primarily to production tax credits from wind-powered generating facilities owned by MidAmerican Energy, PacifiCorp and BHE Renewables. 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.

Income tax effect of foreign income includes, among other items, deferred income tax benefits of $16 million in 2016 and $39 million in 2015 related to the enactment of reductions in the United Kingdom corporate income tax rate. In September 2016, the corporate income tax rate was reduced from 18% to 17% effective April 1, 2020. In November 2015, the corporate income tax rate was reduced from 20% to 19% effective April 1, 2017, with a further reduction to 18% effective April 1, 2020.

Berkshire Hathaway includes the Company in its United States federal income tax return. As of December 31, 2016, the Company had current income taxes payable to Berkshire Hathaway of $27 million. As of December 31, 2015, the Company had current income taxes receivable from Berkshire Hathaway of $286 million.

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

	2016	2015
Deferred income tax assets:		
Federal, state and foreign carryforwards	$ 987	$ 865
Regulatory liabilities	909	834
AROs	326	317
Employee benefits	209	190
Derivative contracts	29	83
Other	707	815
Total deferred income tax assets	3,167	3,104
Valuation allowances	(64)	(35)
Total deferred income tax assets, net	3,103	3,069
Deferred income tax liabilities:		
Property-related items	(14,237)	(13,157)
Regulatory assets	(1,449)	(1,446)
Investments	(962)	(852)
Other	(334)	(299)
Total deferred income tax liabilities	(16,982)	(15,754)
Net deferred income tax liability	$ (13,879)	$ (12,685)

The following table provides the Company's net operating loss and tax credit carryforwards and expiration dates as of December 31, 2016 (in millions):

	Federal	State	Foreign	Total
Net operating loss carryforwards(1)	$ 179	$ 11,549	$ 352	$ 12,080
Deferred income taxes on net operating loss carryforwards	$ 65	$ 674	$ 95	$ 834
Expiration dates	2023-2025	2017-2036	2035-2036	
Tax credits(2)	$ 128	$ 25	$ —	$ 153
Expiration dates	2023-indefinite	2017-indefinite		

(1) The federal net operating loss carry forwards relate principally to net operating loss carry forwards of subsidiaries that are tax residents in both the United States and the United Kingdom. The federal net operating loss carry forwards were generated prior to Berkshire Hathaway Inc.'s ownership and will begin to expire in 2023.

(2) Includes $97 million of deferred foreign tax credits associated with the federal income tax on unremitted tax earnings and profit pools that will begin to be creditable and expire 10 years after the date the foreign earnings are repatriated through actual or deemed dividends. As of December 31, 2016 the statute of limitation had not begun on the foreign tax credit carryforwards.

The United States Internal Revenue Service has closed its examination of the Company's income tax returns through December 31, 2009. Most state tax agencies have closed their examinations of the Company's income tax returns through February 9, 2006, except for (i) Iowa, which is closed through December 31, 2012, (ii) Illinois, which is closed through December 31, 2008 and (iii) the statute of limitations for PacifiCorp's state income tax returns have expired through December 31, 2009, with the exception of California, Oregon and Utah, for which the statute of limitations have expired through March 31, 2006. Examinations have been closed in the United Kingdom through December 31, 2014, in Canada through December 31, 2008 and in the Philippines through December 31, 2012.

A reconciliation of the beginning and ending balances of the Company's net unrecognized tax benefits is as follows for the years ended December 31 (in millions):

	2016	2015
Beginning balance	$ 198	$ 220
Additions based on tax positions related to the current year	7	3
Additions for tax positions of prior years	6	46
Reductions for tax positions of prior years	(11)	(58)
Statute of limitations	(1)	(6)
Settlements	(67)	(6)
Interest and penalties	(4)	(1)
Ending balance	$ 128	$ 198

As of December 31, 2016 and 2015, the Company had unrecognized tax benefits totaling $104 million and $163 million, respectively, that if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect the Company's effective income tax rate.

(12) Employee Benefit Plans

Defined Benefit Plans

Domestic Operations

The Utilities sponsor defined benefit pension plans that cover a majority of all employees of BHE and its domestic energy subsidiaries. These pension plans include noncontributory defined benefit pension plans, supplemental executive retirement plans ("SERP") and a restoration plan for certain executives of NV Energy. The Utilities also provide certain postretirement healthcare and life insurance benefits through various plans to eligible retirees.

Net Periodic Benefit Cost

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

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

	Pension			Other Postretirement		
	2016	2015	2014	2016	2015	2014
Service cost	$ 29	$ 33	$ 36	$ 9	$ 11	$ 14
Interest cost	126	121	131	31	31	46
Expected return on plan assets	(160)	(169)	(164)	(41)	(45)	(53)
Net amortization	46	53	44	(12)	(11)	(3)
Net periodic benefit cost (credit)	$ 41	$ 38	$ 47	$ (13)	$ (14)	$ 4

Funded Status

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

	Pension		Other Postretirement	
	2016	2015	2016	2015
Plan assets at fair value, beginning of year	$ 2,489	$ 2,718	$ 662	$ 858
Employer contributions	78	13	2	2
Participant contributions	—	—	10	9
Actual return on plan assets	163	(17)	41	—
Settlement	(11)	(23)	—	(150)
Benefits paid	(194)	(202)	(49)	(57)
Plan assets at fair value, end of year	$ 2,525	$ 2,489	$ 666	$ 662

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

	Pension		Other Postretirement	
	2016	2015	2016	2015
Benefit obligation, beginning of year	$ 2,934	$ 3,119	$ 740	$ 936
Service cost	29	33	9	11
Interest cost	126	121	31	31
Participant contributions	—	—	10	9
Actuarial loss (gain)	67	(110)	(7)	(43)
Amendment	1	(4)	—	3
Settlement	(11)	(23)	—	(150)
Benefits paid	(194)	(202)	(49)	(57)
Benefit obligation, end of year	$ 2,952	$ 2,934	$ 734	$ 740
Accumulated benefit obligation, end of year	$ 2,929	$ 2,906		

In December 2014, PacifiCorp's subsidiary, 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. No curtailment accounting was triggered as a result of the settlement due to an insignificant impact to the average remaining service lives in the plan.

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

	Pension		Other Postretirement	
	2016	2015	2016	2015
Plan assets at fair value, end of year	$ 2,525	$ 2,489	$ 666	$ 662
Benefit obligation, end of year	2,952	2,934	734	740
Funded status	$ (427)	$ (445)	$ (68)	$ (78)
Amounts recognized on the Consolidated Balance Sheets:				
Other assets	$ 26	$ 7	$ 19	$ 15
Other current liabilities	(15)	(15)	—	—
Other long-term liabilities	(438)	(437)	(87)	(93)
Amounts recognized	$ (427)	$ (445)	$ (68)	$ (78)

The SERPs and restoration plan have no plan assets; however, the Company has Rabbi trusts that hold corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERPs and restoration plan. The cash surrender value of all of the policies included in the Rabbi trusts, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was $242 million and $228 million as of December 31, 2016 and 2015, respectively. These assets are not included in the plan assets in the above table, but are reflected in noncurrent investments and restricted cash and investments on the Consolidated Balance Sheets.

The fair value of plan assets, projected benefit obligation and accumulated benefit obligation for (1) pension and other postretirement benefit plans with a projected benefit obligation in excess of the fair value of plan assets and (2) pension plans with an accumulated benefit obligation in excess of the fair value of plan assets as of December 31 are as follows (in millions):

	Pension		Other Postretirement	
	2016	2015	2016	2015
Fair value of plan assets	$ 1,841	$ 1,811	$ 413	$ 413
Projected benefit obligation	$ 2,294	$ 2,263	$ 500	$ 505
Accumulated benefit obligation	$ 2,278	$ 2,244		

Unrecognized Amounts

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

	Pension		Other Postretirement	
	2016	2015	2016	2015
Net loss	$ 775	$ 768	$ 88	$ 97
Prior service credit	(7)	(25)	(52)	(68)
Regulatory deferrals	(7)	(2)	7	8
Total	$ 761	$ 741	$ 43	$ 37

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2016 and 2015 is as follows (in millions):

	Regulatory Asset	Regulatory Liability	Accumulated Other Comprehensive Loss	Total
Pension				
Balance, December 31, 2014	$ 710	$ (6)	$ 19	$ 723
Net loss (gain) arising during the year	76	5	(6)	75
Net prior service credit arising during the year	(4)	—	—	(4)
Net amortization	(53)	—	—	(53)
Total	19	5	(6)	18
Balance, December 31, 2015	729	(1)	13	741
Net loss arising during the year	76	(11)	—	65
Net prior service cost arising during the year	1	—	—	1
Net amortization	(45)	(1)	—	(46)
Total	32	(12)	—	20
Balance, December 31, 2016	$ 761	$ (13)	$ 13	$ 761

	Regulatory Asset	Regulatory Liability	Total
Other Postretirement			
Balance, December 31, 2014	$ 37	$ (14)	$ 23
Net (gain) loss arising during the year	(1)	1	—
Net prior service cost arising during the year	3	—	3
Net amortization	10	1	11
Total	12	2	14
Balance, December 31, 2015	49	(12)	37
Net gain arising during the year	(5)	(1)	(6)
Net amortization	11	1	12
Total	6	—	6
Balance, December 31, 2016	$ 55	$ (12)	$ 43

The net loss, prior service credit and regulatory deferrals that will be amortized in 2017 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Credit	Regulatory Deferrals	Total
Pension	$ 33	$ (3)	$ (2)	$ 28
Other postretirement	2	(16)	1	(13)
Total	$ 35	$ (19)	$ (1)	$ 15

Plan Assumptions

Weighted-average assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2016	2015	2014	2016	2015	2014
Benefit obligations as of December 31:						
Discount rate	4.06%	4.43%	4.00%	4.01%	4.33%	3.88%
Rate of compensation increase	2.75%	2.75%	2.75%	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	4.43%	4.00%	4.81%	4.33%	3.93%	4.82%
Expected return on plan assets	6.78%	6.88%	6.86%	7.03%	7.00%	7.34%
Rate of compensation increase	2.75%	2.75%	3.00%	N/A	N/A	N/A

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

	2016	2015
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	7.40%	7.70%
Rate that the cost trend rate gradually declines to	5.00%	5.00%
Year that the rate reaches the rate it is assumed to remain at	2025	2025

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

	One Percentage-Point	
	Increase	Decrease
Increase (decrease) in:		
Total service and interest cost for the year ended December 31, 2016	$ 1	$ —
Other postretirement benefit obligation as of December 31, 2016	4	(4)

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $14 million and $4 million, respectively, during 2017. Funding to the established pension trusts is based upon the actuarially determined costs of the plans and the requirements of the Internal Revenue Code, the Employee Retirement Income Security Act of 1974 and the Pension Protection Act of 2006, as amended. The Company considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the Pension Protection Act of 2006, as amended. The Company's funding policy for its other postretirement benefit plans is to generally contribute an amount equal to the net periodic benefit cost.

The expected benefit payments to participants in the Company's pension and other postretirement benefit plans for 2017 through 2021 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2017	$ 219	$ 56
2018	226	57
2019	224	57
2020	221	60
2021	214	57
2022-2026	1,002	259

Plan Assets

Investment Policy and Asset Allocations

The Company's investment policy for its pension and other postretirement benefit plans is to balance risk and return through a diversified portfolio of debt securities, equity securities and other alternative investments. Maturities for debt securities are managed to targets consistent with prudent risk tolerances. The plans retain outside investment advisors to manage plan investments within the parameters outlined by each plan's Pension and Employee Benefits Plans Administrative Committee. The investment portfolio is managed in line with the investment policy with sufficient liquidity to meet near-term benefit payments.

The target allocations (percentage of plan assets) for the Company's pension and other postretirement benefit plan assets are as follows as of December 31, 2016:

	Pension	Other Postretirement
	%	%
PacifiCorp:		
Debt securities[1]	33-37	33-37
Equity securities[1]	53-57	61-65
Limited partnership interests	8-12	1-3
Other	0-1	0-1
MidAmerican Energy:		
Debt securities[1]	20-40	25-45
Equity securities[1]	60-80	50-80
Real estate funds	2-8	—
Other	0-5	0-5
NV Energy:		
Debt securities[1]	53-77	40
Equity securities[1]	23-47	60

(1) For purposes of target allocation percentages and consistent with the plans' investment policy, investment funds are allocated based on the underlying investments in debt and equity securities.

Fair Value Measurements

The Company adopted ASU No. 2015-07, "Fair Value Measurement (Topic 820) - Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share (or its Equivalent)" effective January 1, 2016 under a retrospective method.

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

	Input Levels for Fair Value Measurements[1]			
	Level 1	Level 2	Level 3	Total
As of December 31, 2016:				
Cash equivalents	$ 4	$ 54	$ —	$ 58
Debt securities:				
United States government obligations	161	—	—	161
International government obligations	—	2	—	2
Corporate obligations	—	295	—	295
Municipal obligations	—	20	—	20
Agency, asset and mortgage-backed obligations	—	112	—	112
Equity securities:				
United States companies	583	—	—	583
International companies	117	—	—	117
Investment funds[2]	146	—	—	146
Total assets in the fair value hierarchy	$ 1,011	$ 483	$ —	1,494
Investment funds[2] measured at net asset value				920
Limited partnership interests[3] measured at net asset value				61
Real estate funds measured at net asset value				50
Total assets measured at fair value				$ 2,525
As of December 31, 2015:				
Cash equivalents	$ —	$ 26	$ —	$ 26
Debt securities:				
United States government obligations	155	—	—	155
International government obligations	—	4	—	4
Corporate obligations	—	335	—	335
Municipal obligations	—	25	—	25
Agency, asset and mortgage-backed obligations	—	154	—	154
Equity securities:				
United States companies	586	—	—	586
International companies	122	—	—	122
Investment funds[2]	144	—	—	144
Total assets in the fair value hierarchy	$ 1,007	$ 544	$ —	1,551
Investment funds[2] measured at net asset value				823
Limited partnership interests[3] measured at net asset value				65
Real estate funds measured at net asset value				50
Total assets measured at fair value				$ 2,489

(1) Refer to Note 15 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 62% and 38%, respectively, for 2016 and 66% and 34%, respectively, for 2015. Additionally, these funds are invested in United States and international securities of approximately 60% and 40%, respectively, for 2016 and 58% and 42%, respectively, for 2015.

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

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

	Input Levels for Fair Value Measurements[1]			
	Level 1	Level 2	Level 3	Total
As of December 31, 2016:				
Cash equivalents	$ 18	$ 2	$ —	$ 20
Debt securities:				
United States government obligations	19	—	—	19
Corporate obligations	—	29	—	29
Municipal obligations	—	39	—	39
Agency, asset and mortgage-backed obligations	—	25	—	25
Equity securities:				
United States companies	217	—	—	217
International companies	5	—	—	5
Investment funds[2]	152	—	—	152
Total assets in the fair value hierarchy	$ 411	$ 95	$ —	506
Investment funds[2] measured at net asset value				156
Limited partnership interests[3] measured at net asset value				4
Total assets measured at fair value				$ 666
As of December 31, 2015:				
Cash equivalents	$ 12	$ 1	$ —	$ 13
Debt securities:				
United States government obligations	18	—	—	18
Corporate obligations	—	33	—	33
Municipal obligations	—	41	—	41
Agency, asset and mortgage-backed obligations	—	28	—	28
Equity securities:				
United States companies	216	—	—	216
International companies	6	—	—	6
Investment funds[2]	149	—	—	149
Total assets in the fair value hierarchy	$ 401	$ 103	$ —	504
Investment funds[2] measured at net asset value				154
Limited partnership interests[3] measured at net asset value				4
Total assets measured at fair value				$ 662

(1) Refer to Note 15 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 63% and 37%, respectively, for both 2016 and 2015. Additionally, these funds are invested in United States and international securities of approximately 72% and 28%, respectively, for 2016 and 70% and 30%, respectively, for 2015.

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

For level 1 investments, 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. For level 2 investments, the fair value is determined using pricing models based on observable market inputs. Shares of mutual funds not registered under the Securities Act of 1933, private equity limited partnership interests, common and commingled trust funds and investment entities are reported at fair value based on the net asset value per unit, which is used for expedience purposes. A fund's net asset value is based on the fair value of the underlying assets held by the fund less its liabilities.

Foreign Operations

Certain wholly-owned subsidiaries of Northern Powergrid participate in the Northern Powergrid group of the United Kingdom industry-wide Electricity Supply Pension Scheme (the "UK Plan"), which provides pension and other related defined benefits, based on final pensionable pay, to the majority of the employees of Northern Powergrid. The UK Plan is closed to employees hired after July 23, 1997. Employees hired after that date are covered by a defined contribution plan sponsored by a wholly-owned subsidiary of Northern Powergrid.

Net Periodic Benefit Cost

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

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

	2016	2015	2014
Service cost	$ 20	$ 24	$ 24
Interest cost	72	79	95
Expected return on plan assets	(110)	(116)	(124)
Net amortization	44	62	51
Net periodic benefit cost	$ 26	$ 49	$ 46

Funded Status

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

	2016	2015
Plan assets at fair value, beginning of year	$ 2,276	$ 2,368
Employer contributions	55	77
Participant contributions	1	2
Actual return on plan assets	349	48
Benefits paid	(115)	(91)
Foreign currency exchange rate changes	(397)	(128)
Plan assets at fair value, end of year	$ 2,169	$ 2,276

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

	2016	2015
Benefit obligation, beginning of year	$ 2,142	$ 2,279
Service cost	20	24
Interest cost	72	79
Participant contributions	1	2
Actuarial loss (gain)	387	(30)
Benefits paid	(115)	(91)
Foreign currency exchange rate changes	(382)	(121)
Benefit obligation, end of year	$ 2,125	$ 2,142
Accumulated benefit obligation, end of year	$ 1,858	$ 1,891

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

	2016	2015
Plan assets at fair value, end of year	$ 2,169	$ 2,276
Benefit obligation, end of year	2,125	2,142
Funded status	$ 44	$ 134
Amounts recognized on the Consolidated Balance Sheets:		
Other assets	$ 44	$ 134

Unrecognized Amounts

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

	2016	2015
Net loss	$ 590	$ 592

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

	2016	2015
Balance, beginning of year	$ 592	$ 655
Net loss arising during the year	148	38
Net amortization	(44)	(62)
Foreign currency exchange rate changes	(106)	(39)
Total	(2)	(63)
Balance, end of year	$ 590	$ 592

The net loss that will be amortized from accumulated other comprehensive loss in 2017 into net periodic benefit cost is estimated to be $65 million.

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	2016	2015	2014
Benefit obligations as of December 31:			
Discount rate	2.70%	3.70%	3.60%
Rate of compensation increase	3.00%	2.90%	2.80%
Rate of future price inflation	3.00%	2.90%	2.80%
Net periodic benefit cost for the years ended December 31:			
Discount rate	3.70%	3.60%	4.40%
Expected return on plan assets	5.60%	5.60%	6.10%
Rate of compensation increase	2.90%	2.80%	3.15%
Rate of future price inflation	2.90%	2.80%	3.15%

Contributions and Benefit Payments

Employer contributions to the UK Plan are expected to be £37 million during 2017. The expected benefit payments to participants in the UK Plan for 2017 through 2021 and for the five years thereafter, using the foreign currency exchange rate as of December 31, 2016, are summarized below (in millions):

2017	$ 75
2018	77
2019	79
2020	81
2021	83
2022-2026	448

Plan Assets

Investment Policy and Asset Allocations

The investment policy for the UK Plan is to balance risk and return through a diversified portfolio of debt securities, equity securities and real estate. Maturities for debt securities are managed to targets consistent with prudent risk tolerances. The UK Plan retains outside investment advisors to manage plan investments within the parameters set by the trustees of the UK Plan in consultation with Northern Powergrid. The investment portfolio is managed in line with the investment policy with sufficient liquidity to meet near-term benefit payments. The return on assets assumption is based on a weighted-average of the expected historical performance for the types of assets in which the UK Plan invests.

The target allocations (percentage of plan assets) for the UK Plan assets are as follows as of December 31, 2016:

	%
Debt securities(1)	50-55
Equity securities(1)	35-40
Real estate funds and other	5-15

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

Fair Value Measurements

The Company adopted ASU No. 2015-07, "Fair Value Measurement (Topic 820) - Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share (or its Equivalent)" effective January 1, 2016 under a retrospective method.

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

	Input Levels for Fair Value Measurements[1]			
	Level 1	Level 2	Level 3	Total
As of December 31, 2016:				
Cash equivalents	$ 4	$ 83	$ —	$ 87
Debt securities:				
United Kingdom government obligations	718	—	—	718
Equity securities:				
Investment funds[2]	—	1,095	—	1,095
Real estate funds	—	—	105	105
Total	$ 722	$ 1,178	$ 105	2,005
Investment funds[2] measured at net asset value				164
Total assets measured at fair value				$ 2,169
As of December 31, 2015:				
Cash equivalents	$ 46	$ —	$ —	$ 46
Debt securities:				
United Kingdom government obligations	424	—	—	424
Other international government obligations	—	13	—	13
Corporate obligations	—	186	—	186
Equity securities:				
Investment funds[2]	24	1,189	—	1,213
Real estate funds	—	—	204	204
Total	$ 494	$ 1,388	$ 204	2,086
Investment funds[2] measured at net asset value				190
Total assets measured at fair value				$ 2,276

(1) Refer to Note 15 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 44% and 56%, respectively, for both 2016 and 2015.

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

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

	Real Estate Funds		
	2016	2015	2014
Beginning balance	$ 204	$ 199	$ 179
Actual return on plan assets still held at period end	10	18	33
Sales	(80)	—	—
Foreign currency exchange rate changes	(29)	(13)	(13)
Ending balance	$ 105	$ 204	$ 199

Defined Contribution Plans

The Company sponsors various defined contribution plans covering substantially all employees. The Company's contributions vary depending on the plan, but matching contributions are based on each participant's level of contribution, and certain participants receive contributions based on eligible pre-tax annual compensation. Contributions cannot exceed the maximum allowable for tax purposes. The Company's contributions to these plans were $102 million, $90 million and $83 million for the years ended December 31, 2016, 2015 and 2014, respectively.

(13) Asset Retirement Obligations

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

The Company does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain generation, transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Consolidated Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled $2.2 billion as of December 31, 2016 and 2015, respectively.

The following table presents the Company's ARO liabilities by asset type as of December 31 (in millions):

	2016	2015
Fossil fuel facilities	$ 404	$ 443
Quad Cities Station	343	289
Wind generating facilities	124	104
Offshore pipeline facilities	33	31
Solar generating facilities	12	12
Other	38	42
Total asset retirement obligations	$ 954	$ 921
Quad Cities Station nuclear decommissioning trust funds	$ 460	$ 429

The following table reconciles the beginning and ending balances of the Company's ARO liabilities for the years ended December 31 (in millions):

	2016	2015
Beginning balance	$ 921	$ 753
Change in estimated costs	33	104
Additions	25	59
Retirements	(63)	(32)
Accretion	38	37
Ending balance	$ 954	$ 921
Reflected as:		
Other current liabilities	$ 98	$ 92
Other long-term liabilities	856	829
Total ARO liability	$ 954	$ 921

The Nuclear Regulatory Commission regulates the decommissioning of nuclear power plants, which includes the planning and funding for the decommissioning. In accordance with these regulations, MidAmerican Energy submits a biennial report to the Nuclear Regulatory Commission providing reasonable assurance that funds will be available to pay for its share of the Quad Cities Station decommissioning.

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

The 2016 change in estimated costs was primarily the result of a new decommissioning study conducted by the operator of the Quad Cities Station that changed the estimated amount and timing of cash flows. The 2015 change in estimated costs was primarily due to changes in the expected timing and amount of cash flows related to the implementation of the United States Environmental Protection Agency's 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, which was effective in October 2015. In addition to substantially impacting existing AROs, the final rule also resulted in the recognition of additional AROs.

(14) 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 the Utilities as they have an obligation to serve retail customer load in their regulated service territories. The Company also provides nonregulated retail electricity and natural gas services in competitive markets. The Utilities' load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity, wholesale electricity that is purchased and sold, and natural gas supply for retail customers. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. Interest rate risk exists on variable-rate short- and long-term 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, manage, mitigate, monitor and report 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 Notes 2, 6 and 15 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 December 31, 2016:					
Not designated as hedging contracts:					
Commodity assets[1]	$ 42	$ 86	$ 5	$ 2	$ 135
Commodity liabilities[1]	(10)	—	(46)	(150)	(206)
Interest rate assets	15	—	—	—	15
Interest rate liabilities	—	—	(4)	(6)	(10)
Total	47	86	(45)	(154)	(66)
Designated as hedging contracts:					
Commodity assets	1	—	2	3	6
Commodity liabilities	—	—	(14)	(8)	(22)
Interest rate assets	—	8	—	—	8
Interest rate liabilities	—	—	(3)	—	(3)
Total	1	8	(15)	(5)	(11)
Total derivatives	48	94	(60)	(159)	(77)
Cash collateral receivable	—	—	13	61	74
Total derivatives - net basis	$ 48	$ 94	$ (47)	$ (98)	$ (3)
As of December 31, 2015:					
Not designated as hedging contracts:					
Commodity assets[1]	$ 25	$ 72	$ 7	$ 2	$ 106
Commodity liabilities[1]	(4)	—	(113)	(175)	(292)
Interest rate assets	7	—	—	—	7
Interest rate liabilities	—	—	(3)	(6)	(9)
Total	28	72	(109)	(179)	(188)
Designated as hedging contracts:					
Commodity assets	—	—	1	2	3
Commodity liabilities	—	—	(33)	(17)	(50)
Interest rate assets	—	3	—	—	3
Interest rate liabilities	—	—	(4)	(1)	(5)
Total	—	3	(36)	(16)	(49)
Total derivatives	28	75	(145)	(195)	(237)
Cash collateral receivable	—	—	40	63	103
Total derivatives - net basis	$ 28	$ 75	$ (105)	$ (132)	$ (134)

(1) The Company's commodity derivatives not designated as hedging contracts are generally included in regulated rates, and as of December 31, 2016 and 2015, a net regulatory asset of $148 million and $250 million, respectively, was recorded related to the net derivative liability of $71 million and $186 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 for the years ended December 31 (in millions):

	Commodity Derivatives		
	2016	2015	2014
Beginning balance	$ 250	$ 223	$ 182
Changes in fair value recognized in net regulatory assets	(30)	128	96
Net (losses) gains reclassified to operating revenue	(5)	1	(32)
Net losses reclassified to cost of sales	(67)	(102)	(23)
Ending balance	$ 148	$ 250	$ 223

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

	Commodity Derivatives		
	2016	2015	2014
Beginning balance	$ 46	$ 32	$ 12
Changes in fair value recognized in OCI	26	52	(6)
Net gains reclassified to operating revenue	1	9	—
Net (losses) gains reclassified to cost of sales	(57)	(47)	26
Ending balance	$ 16	$ 46	$ 32

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 years ended December 31, 2016, 2015 and 2014, hedge ineffectiveness was insignificant. As of December 31, 2016, the Company had cash flow hedges with expiration dates extending through June 2026 and $14 million of pre-tax unrealized losses are forecasted to be reclassified from AOCI into earnings over the next twelve months as contracts settle.

Derivative Contract Volumes

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

	Unit of Measure	2016	2015
Electricity purchases	Megawatt hours	5	10
Natural gas purchases	Decatherms	271	317
Fuel purchases	Gallons	11	11
Interest rate swaps	US$	714	653
Mortgage commitments, net	US$	(309)	(312)

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 December 31, 2016, 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 $190 million and $288 million as of December 31, 2016 and 2015, respectively, for which the Company had posted collateral of $69 million and $75 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 December 31, 2016 and 2015, the Company would have been required to post $110 million and $198 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.

(15) 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 December 31, 2016:					
Assets:					
Commodity derivatives	$ 5	$ 49	$ 87	$ (22)	$ 119
Interest rate derivatives	—	16	7	—	23
Mortgage loans held for sale	—	359	—	—	359
Money market mutual funds[(2)]	586	—	—	—	586
Debt securities:					
United States government obligations	161	—	—	—	161
International government obligations	—	3	—	—	3
Corporate obligations	—	36	—	—	36
Municipal obligations	—	2	—	—	2
Agency, asset and mortgage-backed obligations	—	2	—	—	2
Equity securities:					
United States companies	250	—	—	—	250
International companies	1,190	—	—	—	1,190
Investment funds	147	—	—	—	147
	$ 2,339	$ 467	$ 94	$ (22)	$ 2,878
Liabilities:					
Commodity derivatives	$ (2)	$ (199)	$ (27)	$ 96	$ (132)
Interest rate derivatives	(1)	(11)	(1)	—	(13)
	$ (3)	$ (210)	$ (28)	$ 96	$ (145)
As of December 31, 2015:					
Assets:					
Commodity derivatives	$ —	$ 16	$ 93	$ (16)	$ 93
Interest rate derivatives	—	5	5	—	10
Mortgage loans held for sale	—	327	—	—	327
Money market mutual funds[(2)]	421	—	—	—	421
Debt securities:					
United States government obligations	133	—	—	—	133
International government obligations	—	2	—	—	2
Corporate obligations	—	39	—	—	39
Municipal obligations	—	1	—	—	1
Agency, asset and mortgage-backed obligations	—	3	—	—	3
Auction rate securities	—	—	44	—	44
Equity securities:					
United States companies	239	—	—	—	239
International companies	1,244	—	—	—	1,244
Investment funds	136	—	—	—	136
	$ 2,173	$ 393	$ 142	$ (16)	$ 2,692
Liabilities:					
Commodity derivatives	$ (13)	$ (283)	$ (46)	$ 119	$ (223)
Interest rate derivatives	—	(13)	(1)	—	(14)
	$ (13)	$ (296)	$ (47)	$ 119	$ (237)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $74 million and $103 million as of December 31, 2016 and 2015, 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 14 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 was determined using pricing models based on available observable market data and the Company's judgment about the assumptions, including liquidity and nonperformance risks, which market participants would use when pricing the asset.

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

	Commodity Derivatives			Interest Rate Derivatives			Auction Rate Securities		
	2016	**2015**	**2014**	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Beginning balance	$ 47	$ 51	$ 60	$ 4	$ —	$ —	$ 44	$ 45	$ 44
Changes included in earnings	8	19	19	121	87	—	5	—	—
Changes in fair value recognized in OCI	(2)	(7)	—	—	—	—	8	(1)	1
Changes in fair value recognized in net regulatory assets	(11)	(19)	5	—	—	—	—	—	—
Purchases	1	1	1	—	—	—	—	—	—
Redemptions	—	—	—	—	—	—	(57)	—	—
Settlements	17	2	1	(119)	(86)	—	—	—	—
Transfers from Level 2	—	—	(35)	—	3	—	—	—	—
Ending balance	$ 60	$ 47	$ 51	$ 6	$ 4	$ —	$ —	$ 44	$ 45

The Company's long-term debt is carried at cost on the Consolidated Financial Statements. The fair value of the Company's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of the Company's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of the Company's long-term debt as of December 31 (in millions):

	2016		2015	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 36,116	$ 40,718	$ 37,972	$ 41,785

(16) Commitments and Contingencies

Commitments

The Company has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2016 are as follows (in millions):

	2017	2018	2019	2020	2021	2022 and Thereafter	Total
Contract type:							
Fuel, capacity and transmission contract commitments	$ 2,370	$ 1,606	$ 1,389	$ 1,208	$ 1,010	$ 10,053	$ 17,636
Construction commitments	852	49	66	1	1	4	973
Operating leases and easements	141	122	101	87	73	1,085	1,609
Maintenance, service and other contracts	303	220	212	186	180	723	1,824
	$ 3,666	$ 1,997	$ 1,768	$ 1,482	$ 1,264	$ 11,865	$ 22,042

Fuel, Capacity and Transmission Contract Commitments

The Utilities have fuel supply and related transportation and lime contracts for their coal- and natural gas-fueled generating facilities. The Utilities expect to supplement these contracts with additional contracts and spot market purchases to fulfill their future fossil fuel needs. The Utilities acquire a portion of their electricity through long-term purchases and exchange agreements. The Utilities have several power purchase agreements with wind-powered generating facilities that are not included in the table above as the payments are based on the amount of energy generated and there are no minimum payments. The Utilities also have contracts for the right to transmit electricity over other entities' transmission lines to facilitate delivery to their customers.

MidAmerican Energy has long-term rail transportation contracts with BNSF Railway Company ("BNSF"), an affiliate company, and Union Pacific Railroad Company for the transportation of coal to all of the MidAmerican Energy-operated coal-fueled generating facilities. For the years ended December 31, 2016, 2015 and 2014, $137 million, $185 million and $159 million, respectively, were incurred for coal transportation services, the majority of which was related to the BNSF agreement.

Construction Commitments

The Company's firm construction commitments reflected in the table above include the following major construction projects:

- MidAmerican Energy's construction of wind-powered generating facilities in 2017 and two Multi-Value Projects approved by the Midcontinent Independent System Operator, Inc. for high voltage transmission lines in Iowa and Illinois in 2017.
- ALP's investments in directly assigned transmission projects from the AESO.
- PacifiCorp's costs associated with investments in emissions control equipment and certain transmission and distribution projects.

Operating Leases and Easements

The Company has non-cancelable operating leases primarily for office equipment, office space, certain operating facilities, land and rail cars. These leases generally require the Company to pay for insurance, taxes and maintenance applicable to the leased property. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. The Company also has non-cancelable easements for land on which its wind-powered generating facilities are located. Rent expense on non-cancelable operating leases totaled \$156 million for 2016, \$161 million for 2015 and \$146 million for 2014.

Maintenance, Service and Other Contracts

The Company has entered into service agreements related to its nonregulated solar and wind-powered projects with third parties to operate and maintain the projects under fixed-fee operating and maintenance agreements. Additionally, the Company has various non-cancelable maintenance, service and other contracts primarily related to turbine and equipment maintenance and various other service agreements.

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.

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 its current and future operations. The Company believes it is in material compliance with all applicable laws and regulations.

Hydroelectric Relicensing

PacifiCorp's Klamath hydroelectric system is currently operating under annual licenses with the FERC. In February 2010, PacifiCorp, the United States Department of the Interior, the United States Department of Commerce, the state of California, the state of Oregon and various other governmental and non-governmental settlement parties signed the Klamath Hydroelectric Settlement Agreement ("KHSA"). Among other things, the KHSA provided that the United States Department of the Interior would conduct scientific and engineering studies to assess whether removal of the Klamath hydroelectric system's mainstem dams was in the public interest and would advance restoration of the Klamath Basin's salmonid fisheries. If it was determined that dam removal should proceed, dam removal would begin no earlier than 2020.

Congress failed to pass legislation needed to implement the original KHSA. In February 2016, the principal parties to the KHSA (PacifiCorp, the states of California and Oregon and the United States Departments of the Interior and Commerce) executed an agreement in principle committing to explore potential amendment of the KHSA to facilitate removal of the Klamath dams through a FERC process without the need for federal legislation. On April 6, 2016, PacifiCorp, the states of California and Oregon, and the United States Departments of the Interior and Commerce and other stakeholders executed an amendment to the KHSA. Consistent with the terms of the amended KHSA, on September 23, 2016, PacifiCorp and the Klamath River Renewal Corporation ("KRRC")" jointly filed an application with the FERC to transfer the license for the four mainstem Klamath River hydroelectric generating facilities from PacifiCorp to the KRRC. Also on September 23, 2016, the KRRC filed an application with the FERC to surrender the license and decommission the facilities. The KRRC's license surrender application included a request for the FERC to refrain from acting on the surrender application until after the transfer of the license to the KRRC is effective.

Under the amended KHSA, PacifiCorp and its customers continue to be protected from uncapped dam removal costs and liabilities. The KRRC must indemnify PacifiCorp from liabilities associated with dam removal. The amended KHSA also limits PacifiCorp's contribution to facilities removal costs to no more than $200 million, of which up to $184 million would be collected from PacifiCorp's Oregon customers with the remainder to be collected from PacifiCorp's California customers. California voters approved a water bond measure in November 2014 from which the state of California's contribution towards facilities removal costs will be drawn. In accordance with this bond measure, additional funding of up to $250 million for facilities removal costs was included in the California state budget in 2016, with the funding effective for at least five years. If facilities removal costs exceed the combined funding that will be available from PacifiCorp's Oregon and California customers and the state of California, sufficient funds would need to be provided by the KRRC or an entity other than PacifiCorp in order for removal to proceed.

If certain conditions in the amended KHSA are not satisfied and the license does not transfer to the KRRC, PacifiCorp will resume relicensing with the FERC.

As of December 31, 2016, PacifiCorp's assets included $68 million of costs associated with the Klamath hydroelectric system's mainstem dams and the associated relicensing and settlement costs, which are being depreciated and amortized in accordance with state regulatory approvals through either December 31, 2019, or December 31, 2022, depending upon the state jurisdiction.

Hydroelectric Commitments

Certain of PacifiCorp's hydroelectric licenses contain requirements for PacifiCorp to make certain capital and operating expenditures related to its hydroelectric facilities. PacifiCorp estimates it is obligated to make capital expenditures of approximately $227 million over the next 10 years related to these licenses.

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.

(17) BHE Shareholders' Equity

Common Stock

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

On February 17, 2017, BHE repurchased from certain family interests of Mr. Walter Scott, Jr. 35,000 shares of its common stock for $19 million. On February 17, 2015, BHE repurchased from certain family interests of Mr. Walter Scott, Jr. 75,000 shares of its common stock for $36 million.

Restricted Net Assets

BHE has maximum debt-to-total capitalization percentage restrictions imposed by its senior unsecured credit facilities expiring in June 2019 which, in certain circumstances, limit BHE's ability to make cash dividends or distributions. As a result of this restriction, BHE has restricted net assets of $15.1 billion as of December 31, 2016.

Certain of BHE's subsidiaries have restrictions on their ability to dividend, loan or advance funds to BHE due to specific legal or regulatory restrictions, including, but not limited to, maximum debt-to-total capitalization percentages and commitments made to state commissions or federal agencies in connection with past acquisitions. As a result of these restrictions, BHE's subsidiaries had restricted net assets of $17.6 billion as of December 31, 2016.

(18) Components of Accumulated Other Comprehensive Loss, Net

The following table shows the change in accumulated other comprehensive loss attributable to BHE shareholders by each component of other comprehensive income (loss), net of applicable income taxes, for the year ended December 31, (in millions):

	Unrecognized Amounts on Retirement Benefits	Foreign Currency Translation Adjustment	Unrealized Gains on Available-For-Sale Securities	Unrealized Gains on Cash Flow Hedges	Accumulated Other Comprehensive Loss Attributable To BHE Shareholders, Net
Balance, December 31, 2013	$ (559)	$ (98)	$ 524	$ 36	$ (97)
Other comprehensive income	69	(314)	(134)	(18)	(397)
Balance, December 31, 2014	(490)	(412)	390	18	(494)
Other comprehensive income (loss)	52	(680)	225	(11)	(414)
Balance, December 31, 2015	(438)	(1,092)	615	7	(908)
Other comprehensive income (loss)	(9)	(583)	(30)	19	(603)
Balance, December 31, 2016	$ (447)	$ (1,675)	$ 585	$ 26	$ (1,511)

Reclassifications from AOCI to net income for the years ended December 31, 2016, 2015 and 2014 were insignificant. For information regarding cash flow hedge reclassifications from AOCI to net income in their entirety, refer to Note 14. Additionally, refer to the "Foreign Operations" discussion in Note 12 for information about unrecognized amounts on retirement benefits reclassifications from AOCI that do not impact net income in their entirety.

(19) Noncontrolling Interests

Included in noncontrolling interests on the Consolidated Balance Sheets are preferred securities of subsidiaries of $58 million as of December 31, 2016 and 2015, consisting of $56 million of 8.061% cumulative preferred securities of Northern Electric plc., a subsidiary of Northern Powergrid, which are redeemable in the event of the revocation of Northern Electric plc.'s electricity distribution license by the Secretary of State, and $2 million of nonredeemable preferred stock of PacifiCorp.

(20) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ending December 31 is as follows (in millions):

	2016	2015	2014
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 1,673	$ 1,764	$ 1,585
Income taxes received, net[1]	$ 1,016	$ 1,666	$ 635
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 547	$ 718	$ 1,143

(1) Includes $1.1 billion, $1.8 billion and $764 million of income taxes received from Berkshire Hathaway in 2016, 2015 and 2014, respectively.

(21) 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. Effective January 1, 2016, MidAmerican Energy transferred the assets and liabilities of its unregulated retail services business to MidAmerican Energy Services, LLC, a subsidiary of BHE. Prior period amounts have been changed to reflect this activity in BHE and Other. Information related to the Company's reportable segments is shown below (in millions):

	Years Ended December 31,		
	2016	2015	2014
Operating revenue:			
PacifiCorp	$ 5,201	$ 5,232	$ 5,252
MidAmerican Funding	2,631	2,515	2,844
NV Energy	2,895	3,351	3,241
Northern Powergrid	995	1,140	1,283
BHE Pipeline Group	978	1,016	1,078
BHE Transmission	502	592	62
BHE Renewables	743	728	623
HomeServices	2,801	2,526	2,144
BHE and Other[1]	676	780	799
Total operating revenue	$ 17,422	$ 17,880	$ 17,326
Depreciation and amortization:			
PacifiCorp	$ 783	$ 780	$ 745
MidAmerican Funding	479	407	351
NV Energy	421	410	379
Northern Powergrid	200	202	198
BHE Pipeline Group	206	204	196
BHE Transmission	241	185	13
BHE Renewables	230	216	152
HomeServices	31	29	29
BHE and Other[1]	—	(5)	(6)
Total depreciation and amortization	$ 2,591	$ 2,428	$ 2,057
Operating income:			
PacifiCorp	$ 1,427	$ 1,344	$ 1,308
MidAmerican Funding	566	451	395
NV Energy	770	812	791
Northern Powergrid	494	593	674
BHE Pipeline Group	455	464	439
BHE Transmission	92	260	16
BHE Renewables	256	255	314
HomeServices	212	184	125
BHE and Other[1]	(21)	(35)	(16)
Total operating income	4,251	4,328	4,046
Interest expense	(1,854)	(1,904)	(1,711)
Capitalized interest	139	74	89
Allowance for equity funds	158	91	98
Interest and dividend income	120	107	38
Other, net	36	39	42
Total income before income tax expense and equity income (loss)	$ 2,850	$ 2,735	$ 2,602

	Years Ended December 31, 2016	2015	2014
Interest expense:			
PacifiCorp	$ 381	$ 383	$ 386
MidAmerican Funding	218	206	197
NV Energy	250	262	283
Northern Powergrid	136	145	151
BHE Pipeline Group	50	66	76
BHE Transmission	153	146	14
BHE Renewables	198	193	175
HomeServices	2	3	4
BHE and Other[1]	466	500	425
Total interest expense	$ 1,854	$ 1,904	$ 1,711
Income tax expense (benefit):			
PacifiCorp	$ 341	$ 328	$ 310
MidAmerican Funding	(139)	(150)	(122)
NV Energy	200	207	195
Northern Powergrid	22	35	110
BHE Pipeline Group	163	158	149
BHE Transmission	26	63	28
BHE Renewables	(32)	41	65
HomeServices	81	72	44
BHE and Other[1]	(259)	(304)	(190)
Total income tax expense (benefit)	$ 403	$ 450	$ 589
Capital expenditures:			
PacifiCorp	$ 903	$ 916	$ 1,066
MidAmerican Funding	1,637	1,448	1,527
NV Energy	529	571	558
Northern Powergrid	579	674	675
BHE Pipeline Group	226	240	257
BHE Transmission	466	966	222
BHE Renewables	719	1,034	2,221
HomeServices	20	16	17
BHE and Other	11	10	12
Total capital expenditures	$ 5,090	$ 5,875	$ 6,555

	As of December 31,		
	2016	2015	2014
Property, plant and equipment, net:			
PacifiCorp	$ 19,162	$ 19,039	$ 18,755
MidAmerican Funding	12,835	11,737	10,535
NV Energy	9,825	9,767	9,648
Northern Powergrid	5,148	5,790	5,599
BHE Pipeline Group	4,423	4,345	4,286
BHE Transmission	5,810	5,301	5,567
BHE Renewables	5,302	4,805	4,897
HomeServices	78	70	68
BHE and Other	(74)	(85)	(107)
Total property, plant and equipment, net	$ 62,509	$ 60,769	$ 59,248
Total assets:			
PacifiCorp	$ 23,563	$ 23,550	$ 23,404
MidAmerican Funding	17,571	16,315	15,164
NV Energy	14,320	14,656	14,256
Northern Powergrid	6,433	7,317	7,059
BHE Pipeline Group	5,144	4,953	4,951
BHE Transmission	8,378	7,553	7,979
BHE Renewables	7,010	5,892	6,082
HomeServices	1,776	1,705	1,622
BHE and Other	1,245	1,677	1,299
Total assets	$ 85,440	$ 83,618	$ 81,816

	Years Ended December 31,		
	2016	2015	2014
Operating revenue by country:			
United States	$ 15,895	$ 16,121	$ 15,857
United Kingdom	995	1,140	1,281
Canada	506	600	78
Philippines and other	26	19	110
Total operating revenue by country	$ 17,422	$ 17,880	$ 17,326
Income before income tax expense and equity income by country:			
United States	$ 2,264	$ 2,034	$ 2,001
United Kingdom	382	472	557
Canada	135	165	4
Philippines and other	69	64	40
Total income before income tax expense and equity income by country:	$ 2,850	$ 2,735	$ 2,602

	As of December 31,		
	2016	2015	2014
Property, plant and equipment, net by country:			
United States	$ 51,671	$ 49,680	$ 47,918
United Kingdom	5,020	5,757	5,563
Canada	5,803	5,298	5,570
Philippines and other	15	34	197
Total property, plant and equipment, net by country	$ 62,509	$ 60,769	$ 59,248

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

The following table shows the change in the carrying amount of goodwill by reportable segment for the years ended December 31, 2016 and 2015 (in millions):

	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	Home-Services	BHE and Other	Total
December 31, 2014	$ 1,129	$ 2,102	$ 2,369	$ 1,100	$ 127	$ 1,657	$ 95	$ 761	$ 3	$9,343
Acquisitions	—	—	—	—	—	44	—	33	—	77
Foreign currency translation	—	—	—	(44)	—	(273)	—	—	(1)	(318)
Other	—	—	—	—	(26)	—	—	—	—	(26)
December 31, 2015	1,129	2,102	2,369	1,056	101	1,428	95	794	2	9,076
Acquisitions	—	—	—	—	—	4	—	46	—	50
Foreign currency translation	—	—	—	(126)	—	42	—	—	(2)	(86)
Other	—	—	—	—	(26)	(4)	—	—	—	(30)
December 31, 2016	$ 1,129	$ 2,102	$ 2,369	$ 930	$ 75	$ 1,470	$ 95	$ 840	$ —	$9,010

PacifiCorp and its subsidiaries
Consolidated Financial Section

Item 6. Selected Financial Data

The following table sets forth PacifiCorp's selected consolidated historical financial data, which should be read in conjunction with the information in Item 7 of this Form 10-K and with PacifiCorp's historical Consolidated Financial Statements and notes thereto in Item 8 of this Form 10-K. The selected consolidated historical financial data has been derived from PacifiCorp's audited historical Consolidated Financial Statements and notes thereto (in millions).

	Years Ended December 31,				
	2016	2015	2014	2013	2012
Consolidated Statement of Operations Data:					
Operating revenue	$ 5,201	$ 5,232	$ 5,252	$ 5,147	$ 4,882
Operating income	1,426	1,340	1,300	1,264	1,021
Net income	763	695	698	682	537

	As of December 31,				
	2016	2015	2014	2013	2012
Consolidated Balance Sheet Data:					
Total assets(1)(2)	$ 22,394	$ 22,367	$ 22,205	$ 21,559	$ 21,581
Short-term debt	270	20	20	—	—
Current portion of long-term debt and capital lease obligations	58	68	134	238	267
Long-term debt and capital lease obligations, excluding current portion(2)	7,021	7,078	6,885	6,605	6,559
Total shareholders' equity	7,390	7,503	7,756	7,787	7,644

(1) In December 2015, PacifiCorp retrospectively adopted Accounting Standards Update No. 2015-17, which resulted in the reclassification of current deferred income tax assets in the amounts of $28 million, $66 million, and $112 million, as of December 31, 2014, 2013 and 2012, respectively, as reductions in noncurrent deferred income tax liabilities.

(2) In December 2015, PacifiCorp retrospectively adopted Accounting Standards Update No. 2015-03, which resulted in the reclassification of certain deferred debt issuance costs previously recognized within other assets in the amounts of $34 million, $34 million, and $35 million, as of December 31, 2014, 2013, and 2012, respectively, as reductions in long-term debt.

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

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

Results of Operations

Overview

Net income for the year ended December 31, 2016 was $763 million, an increase of $68 million, or 10%, compared to 2015. Net income increased due to higher margins of $86 million and lower operations and maintenance expenses of $18 million, partially offset by higher depreciation and amortization of $13 million, lower AFUDC of $9 million and higher property taxes of $5 million. Margins increased primarily due to lower purchased electricity costs, higher retail revenue, lower coal-fueled generation and lower natural gas costs, partially offset by lower wholesale electricity revenue. The increase in retail revenue was primarily due to higher retail rates. Retail customer volumes decreased by 0.6% due to lower commercial customer usage in Utah and lower industrial customer usage primarily in Utah and Oregon, partially offset by an increase in the average number of residential customers in Utah and Oregon, an increase in the average number of commercial customers in Utah and the impacts of weather on residential customer volumes. Energy generated decreased 5% for 2016 compared to 2015 due to lower coal-fueled generation, partially offset by higher hydroelectric, gas-fueled and wind-powered generation. Wholesale electricity sales volumes decreased 25% and purchased electricity volumes decreased 2%.

Net income for the year ended December 31, 2015 was $695 million, a decrease of $3 million compared to 2014. Net income decreased due to recognition of insurance recoveries for a fire claim in 2014, higher depreciation and amortization of $31 million, lower AFUDC of $25 million and higher property taxes, partially offset by higher margins of $109 million. Margins increased primarily due to higher retail revenue, lower purchased electricity prices, lower natural gas generation and costs, Utah Mine Disposition costs in 2014 and lower coal generation, partially offset by higher purchased electricity volumes, lower wholesale electricity revenue from lower volumes and prices and lower retail customer volumes. The increase in retail revenue was primarily due to higher retail rates. Retail customer volumes decreased 0.7% 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, an increase in the average number of commercial customers in Utah and the impacts of weather on residential, commercial and irrigation customer volumes. Energy generated decreased 6% for 2015 compared to 2014 due to lower availability and dispatch of natural gas-fueled generation and lower hydroelectric and wind-powered generation, partially offset by the addition of Lake Side 2. Wholesale electricity sales volumes decreased 13% and purchased electricity volumes increased 19%.

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

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

	2016	2015	Change		2015	2014	Change	
Gross margin (in millions):								
Operating revenue	$ 5,201	$ 5,232	$ (31)	(1)%	$ 5,232	$ 5,252	$ (20)	— %
Energy costs	1,751	1,868	(117)	(6)	1,868	1,997	(129)	(6)
Gross margin	$ 3,450	$ 3,364	$ 86	3	$ 3,364	$ 3,255	$ 109	3
Sales (GWh):								
Residential	16,058	15,566	492	3 %	15,566	15,568	(2)	— %
Commercial	16,857	17,262	(405)	(2)	17,262	17,073	189	1
Industrial and irrigation	20,924	21,403	(479)	(2)	21,403	21,934	(531)	(2)
Other	479	410	69	17	410	424	(14)	(3)
Total retail	54,318	54,641	(323)	(1)	54,641	54,999	(358)	(1)
Wholesale	6,641	8,889	(2,248)	(25)	8,889	10,270	(1,381)	(13)
Total sales	60,959	63,530	(2,571)	(4)	63,530	65,269	(1,739)	(3)
Average number of retail customers (in thousands)	1,841	1,813	28	2 %	1,813	1,783	30	2 %
Average revenue per MWh:								
Retail	$ 89.55	$ 87.99	$ 1.56	2 %	$ 87.99	$ 85.73	$ 2.26	3 %
Wholesale	$ 26.46	$ 29.92	$ (3.46)	(12)%	$ 29.92	$ 33.94	$ (4.02)	(12)%
Sources of energy (GWh)[1]:								
Coal	36,578	41,298	(4,720)	(11)%	41,298	42,218	(920)	(2)%
Natural gas	9,884	9,222	662	7	9,222	10,881	(1,659)	(15)
Hydroelectric[2]	3,843	2,914	929	32	2,914	3,782	(868)	(23)
Wind and other[2]	3,253	2,892	361	12	2,892	3,318	(426)	(13)
Total energy generated	53,558	56,326	(2,768)	(5)	56,326	60,199	(3,873)	(6)
Energy purchased	11,429	11,646	(217)	(2)	11,646	9,817	1,829	19
Total	64,987	67,972	(2,985)	(4)	67,972	70,016	(2,044)	(3)
Average cost of energy per MWh:								
Energy generated[3]	$ 19.27	$ 19.38	$ (0.11)	(1)%	$ 19.38	$ 20.71	$ (1.33)	(6)%
Energy purchased	$ 44.64	$ 49.92	$ (5.28)	(11)%	$ 49.92	$ 58.56	$ (8.64)	(15)%

(1) GWh amounts are net of energy used by the related generating facilities.

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

(3) The average cost per MWh of energy generated includes only the cost of fuel associated with the generating facilities.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Gross margin increased $86 million, or 3%, for 2016 compared to 2015 primarily due to:

- $71 million of lower purchased electricity costs primarily due to lower average market prices;
- $57 million of higher retail revenues primarily due to higher retail rates;
- $37 million of lower coal costs primarily due to decreased generation of $95 million, partially offset by higher average unit costs of $31 million and charges related to damaged longwall mining equipment of $20 million; and
- $22 million of lower natural gas costs due to lower market prices, partially offset by increased generation.

The increases above were partially offset by:

- $90 million of lower wholesale electricity revenue due to lower volumes and prices.

Operations and maintenance decreased $18 million, or 2%, for 2016 compared to 2015 primarily due to lower plant maintenance costs associated with reduced generation and lower labor and benefit costs due to lower headcount, partially offset by a Washington rate case decision disallowing returns on recent selective catalytic reduction projects.

Depreciation and amortization increased $13 million, or 2%, for 2016 compared to 2015 primarily due to higher plant-in-service.

Taxes, other than income taxes increased $5 million, or 3%, for 2016 compared to 2015 due to higher property taxes primarily from higher assessed property values.

Allowance for borrowed and equity funds decreased $9 million, or 18%, for 2016 compared to 2015 primarily due to lower qualified construction work-in-progress balances.

Income tax expense increased $12 million, or 4%, for 2016 compared to 2015 and the effective tax rate was 31% and 32% for 2016 and 2015, respectively. The decrease in the effective tax rate is due to higher production tax credits associated with PacifiCorp's wind-powered generating facilities.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

Gross margin increased $109 million, or 3%, for 2015 compared to 2014 primarily due to:

- $131 million of lower natural gas costs due to decreased generation, primarily as a result of lower availability and dispatch, and lower average unit costs, partially offset by increased generation from the addition of Lake Side 2;
- $109 million of increases mainly from higher retail rates; and
- $25 million of lower coal costs primarily due to decreased generation, including the idling of the Carbon Facility in April 2015 and Utah Mine Disposition costs in 2014.

The increases above were partially offset by:

- $83 million of lower wholesale electricity revenue due to lower volumes and prices;
- $31 million of lower REC revenue primarily due to the effects of established adjustment mechanisms;
- $21 million of lower net deferrals of incurred net power costs in accordance with established adjustment mechanisms;
- $16 million of lower retail revenues from a 0.7% decrease in retail customer volumes due to 1.8% lower customer usage primarily by industrial customers in Utah and Wyoming and residential customers across the service territory, partially offset by a 0.8% increase in the average number of residential customers in Utah and Oregon and commercial customers in Utah and a 0.3% increase due to the impacts of weather on residential, commercial and irrigation customer volumes; and

- $6 million of higher purchased electricity costs due to higher volumes substantially offset by lower average market prices.

Operations and maintenance increased $25 million, or 2%, for 2015 compared to 2014 primarily due to recognition in 2014 of insurance recoveries expected from the Sanpete County, Utah rangeland fire and higher chemical costs from mercury control equipment installed in early 2015, partially offset by lower labor and benefit costs.

Depreciation and amortization increased $31 million, or 4%, for 2015 compared to 2014 primarily due to higher plant in-service, including Lake Side 2.

Taxes, other than income taxes increased $13 million, or 8%, for 2015 compared to 2014 due to higher property taxes primarily from higher assessed property values and higher plant in-service.

Allowance for borrowed and equity funds decreased $25 million, or 33%, for 2015 compared to 2014 due to lower qualified construction work-in-progress balances and lower rates.

Income tax expense increased $19 million, or 6%, for 2015 compared to 2014 and the effective tax rate was 32% and 31% for 2015 and 2014, respectively. The increase in the effective tax rate was primarily due to lower production tax credits associated with PacifiCorp's wind-powered generating facilities.

Liquidity and Capital Resources

As of December 31, 2016, PacifiCorp's total net liquidity was as follows (in millions):

Cash and cash equivalents	$ 17
Credit facilities[(1)]	1,000
Less:	
Short-term debt	(270)
Tax-exempt bond support	(142)
Net credit facilities	588
Total net liquidity	$ 605
Credit facilities:	
Maturity dates	2018, 2019

(1) Refer to Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding PacifiCorp's credit facilities.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2016 and 2015 were $1.6 billion and $1.7 billion, respectively. The change was primarily due to higher cash paid for income taxes, payment for USA Power final judgment and postjudgment interest and lower receipts from wholesale electricity sales, partially offset by lower purchased electricity payments, lower fuel payments, higher receipts from retail customers and lower cash collateral posted for derivative contracts.

Net cash flows from operating activities for the years ended December 31, 2015 and 2014 were $1.7 billion and $1.6 billion, respectively. The change was primarily due to lower cash paid for income taxes, lower fuel and purchased electricity payments and partial insurance recovery for Sanpete County, Utah rangeland fire costs incurred, partially offset by lower receipts from wholesale electricity sales and increases in cash collateral posted for derivative contracts.

The timing of PacifiCorp's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods and assumptions for each payment date.

In December 2015, the Protecting Americans from Tax Hikes Act of 2015 ("PATH") was signed into law, extending bonus depreciation for qualifying property acquired and placed in-service before January 1, 2020 (bonus depreciation rates will be 50% in 2015-2017, 40% in 2018, and 30% in 2019), with an additional year for certain longer lived assets. As a result of PATH, PacifiCorp's cash flows from operations are expected to benefit due to bonus depreciation on qualifying assets placed in-service through 2019.

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. As a result of the Act, PacifiCorp's cash flows from operations benefited in 2015 due to bonus depreciation on qualifying assets placed in-service.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2016 and 2015 were $(869) million and $(918) million, respectively. The change primarily reflects, a current year net distribution from an affiliate of $26 million, a prior year service territory acquisition of $23 million, and a decrease in capital expenditures of $13 million, partially offset by a prior year equipment sale to an affiliate of $13 million. Refer to "Future Uses of Cash" for discussion of capital expenditures.

Net cash flows from investing activities for the years ended December 31, 2015 and 2014 were $(918) million and $(1.079) billion, respectively. The change was primarily due to a decrease in capital expenditures of $150 million.

Financing Activities

Short-term Debt and Credit Facilities

Regulatory authorities limit PacifiCorp to $1.5 billion of short-term debt. As of December 31, 2016, PacifiCorp had $270 million of short-term debt outstanding at a weighted average interest rate of 0.96%, and as of December 31, 2015, had $20 million of short-term debt outstanding at a weighted average interest rate of 0.65%. For further discussion, refer to Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Long-term Debt

PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional $1.325 billion of long-term debt. PacifiCorp must make a notice filing with the WUTC prior to any future issuance. PacifiCorp currently has an effective shelf registration statement with the SEC to issue up to $1.325 billion additional first mortgage bonds through January 2019.

PacifiCorp made repayments on long-term debt totaling $66 million and $122 million during the years ended December 31, 2016 and 2015, respectively.

As of December 31, 2016, PacifiCorp had $255 million of letters of credit providing credit enhancement and liquidity support for variable-rate tax-exempt bond obligations totaling $251 million plus interest. These letters of credit were fully available as of December 31, 2016 and expire periodically through March 2019.

PacifiCorp's Mortgage and Deed of Trust creates a lien on most of PacifiCorp's electric utility property, allowing the issuance of bonds based on a percentage of utility property additions, bond credits arising from retirement of previously outstanding bonds or deposits of cash. The amount of bonds that PacifiCorp may issue generally is also subject to a net earnings test. As of December 31, 2016, PacifiCorp estimated it would be able to issue up to $9.7 billion of new first mortgage bonds under the most restrictive issuance test in the mortgage. Any issuances are subject to market conditions and amounts may be further limited by regulatory authorizations or commitments or by covenants and tests contained in other financing agreements. PacifiCorp also has the ability to release property from the lien of the mortgage on the basis of property additions, bond credits or deposits of cash.

Preferred Stock

As of December 31, 2016 and 2015, PacifiCorp had non-redeemable preferred stock outstanding with an aggregate stated value of $2 million.

Common Shareholder's Equity

In February 2017, PacifiCorp declared a dividend of $100 million payable to PPW Holdings LLC in March 2017.

In 2016 and 2015, PacifiCorp declared and paid dividends of $875 million and $950 million, respectively, to PPW Holdings LLC.

Capitalization

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

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

Future Uses of Cash

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

Capital Expenditures

PacifiCorp has significant future capital requirements. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, changes in 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.

Historical and forecast capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, for the years ended December 31 are as follows (in millions):

	Historical			**Forecast**		
	2014	**2015**	**2016**	**2017**	**2018**	**2019**
Transmission system investment	$ 262	$ 137	$ 94	$ 119	$ 108	$ 85
Environmental	158	114	58	32	21	14
Wind investment	—	—	110	31	181	740
Operating and other	646	665	641	668	675	781
Total	$ 1,066	$ 916	$ 903	$ 850	$ 985	$ 1,620

PacifiCorp's historical and forecast capital expenditures include the following:

- Transmission system investment includes main grid reinforcement costs, construction costs for the 170-mile single-circuit 345-kV Sigurd-Red Butte transmission line that was placed in-service in May 2015 and initial development costs for several other long-term projects.

- Environmental includes the installation of new or the replacement of existing emissions control equipment at certain generating facilities, 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 controls systems and mercury emissions control systems, as well as expenditures for the management of coal combustion residuals.

- Wind investment includes initial costs for new wind plant construction projects and repowering of existing wind plants. Wind investments totaling $110 million in 2016 for the purposes of repowering certain existing wind-powered generating facilities and the construction of a new wind-powered generating facility. The repowering projects entail the replacement of significant components of older turbines. Planned spending for the repowering and new wind-powered generating facilities totals $31 million in 2017, $181 million in 2018 and $740 million in 2019. The energy production from the repowered and new wind-powered generating facilities is expected to qualify for 100% of the federal renewable electricity production tax credit available for 10 years once the equipment is placed in-service.

- Remaining investments relate to operating projects that consist of routine expenditures for generation, transmission, distribution and other infrastructure needed to serve existing and expected demand, including upgrades to customer meters in Oregon and Idaho.

Obligations and Commitments

Contractual Obligations

PacifiCorp has contractual cash obligations that may affect its consolidated financial condition. The following table summarizes PacifiCorp's material contractual cash obligations as of December 31, 2016 (in millions):

	Payments Due By Periods				
	2017	2018-2019	2020-2021	2022 and Thereafter	Total
Long-term debt, including interest:					
Fixed-rate obligations	$ 357	$ 1,522	$ 1,027	$ 8,894	$ 11,800
Variable-rate obligations(1)	53	90	42	223	408
Capital leases, including interest	9	8	9	20	46
Operating leases and easements	5	10	9	39	63
Asset retirement obligations	21	23	38	351	433
Power purchase agreements - commercially operable(2):					
Electricity commodity contracts	207	231	225	903	1,566
Electricity capacity contracts	37	70	62	665	834
Electricity mixed contracts	9	16	15	62	102
Power purchase agreements - non-commercially operable(2)	10	30	35	390	465
Transmission	109	196	108	467	880
Fuel purchase agreements(2):					
Natural gas supply and transportation	62	56	55	260	433
Coal supply and transportation	734	1,156	798	1,147	3,835
Other purchase obligations	115	132	42	72	361
Other long-term liabilities(3)	14	9	13	52	88
Total contractual cash obligations	$ 1,742	$ 3,549	$ 2,478	$ 13,545	$ 21,314

(1) Consists of principal and interest for tax-exempt bond obligations with interest rates scheduled to reset periodically prior to maturity. Future variable interest rates are assumed to equal December 31, 2016 rates. Refer to "Interest Rate Risk" in Item 7A of this Form 10-K for additional discussion related to variable-rate liabilities.

(2) Commodity contracts are agreements for the delivery of energy. Capacity contracts are agreements that provide rights to energy output, generally of a specified generating facility. Forecasted or other applicable estimated prices were used to determine total dollar value of the commitments. PacifiCorp has several contracts for purchases of electricity from facilities that have not yet achieved commercial operation. To the extent any of these facilities do not achieve commercial operation, PacifiCorp has no obligation to the counterparty.

(3) Includes environmental and hydroelectric relicensing commitments recorded in the Consolidated Balance Sheets that are contractually or legally binding. Excludes regulatory liabilities and employee benefit plan obligations that are not legally or contractually fixed as to timing and amount. Deferred income taxes are excluded since cash payments are based primarily on taxable income for each year. Uncertain tax positions are also excluded because the amounts and timing of cash payments are not certain.

Regulatory Matters

PacifiCorp is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further discussion regarding PacifiCorp's general regulatory framework and current regulatory matters.

Environmental Laws and Regulations

PacifiCorp is subject to federal, state, local and foreign laws and regulations regarding air and water quality, RPS, 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 PacifiCorp'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. PacifiCorp 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. Environmental laws and regulations continue to evolve, and PacifiCorp is unable to predict the impact of the changing laws and regulations on its operations and financial results.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for additional information regarding environmental laws and regulations and "Liquidity and Capital Resources" for PacifiCorp's forecast environmental-related capital expenditures.

Collateral and Contingent Features

Debt and preferred securities of PacifiCorp are rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of PacifiCorp's ability to, in general, meet the obligations of its issued debt or preferred securities. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time. As of December 31, 2016, PacifiCorp's credit ratings for its senior secured debt and its issuer credit ratings for senior unsecured debt from the three recognized credit rating agencies were investment grade.

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

In accordance with industry practice, certain wholesale 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" if there is a material adverse change in PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of December 31, 2016, PacifiCorp would have been required to post $221 million of additional collateral. PacifiCorp's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors. Refer to Note 11 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for a discussion of PacifiCorp's collateral requirements specific to PacifiCorp's derivative contracts.

Limitations

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

PacifiCorp's revolving credit and other financing agreements contain customary covenants and default provisions, including a covenant not to exceed a specified debt-to-capitalization ratio of 0.65 to 1.0 as of the last day of each fiscal quarter. Management believes that PacifiCorp could have borrowed an additional $6.4 billion as of December 31, 2016 without exceeding this threshold. Any additional borrowings would be subject to market conditions, and amounts may be further limited by regulatory authorizations or by covenants and tests contained in other financing agreements.

The state regulatory orders that authorized BHE's acquisition of PacifiCorp contain restrictions on PacifiCorp's ability to pay dividends to the extent that they would reduce PacifiCorp's common equity below specified percentages of defined capitalization. As of December 31, 2016, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings LLC or BHE without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 44% of its total capitalization, excluding short-term debt and current maturities of long-term debt. The terms of this commitment treat 50% of PacifiCorp's remaining balance of preferred stock in existence prior to the acquisition of PacifiCorp by BHE as common equity. As of December 31, 2016, PacifiCorp's actual common stock equity percentage, as calculated under this measure, was 51%, and management believes that PacifiCorp could have declared a dividend of $1.9 billion under this commitment.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings LLC or BHE if PacifiCorp's senior unsecured debt is rated BBB- or lower by Standard & Poor's Rating Services or Fitch Ratings or Baa3 or lower by Moody's Investor Service, as indicated by two of the three rating services. As of December 31, 2016, PacifiCorp met the minimum required senior unsecured debt ratings for making distributions.

Inflation

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

Off-Balance Sheet Arrangements

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

New Accounting Pronouncements

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

Critical Accounting Estimates

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

Accounting for the Effects of Certain Types of Regulation

PacifiCorp prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, PacifiCorp defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in rates occur.

PacifiCorp continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit PacifiCorp's ability to recover its costs. PacifiCorp believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels. If it becomes no longer probable that the deferred costs or income will be included in future rates, the related regulatory assets and liabilities will be written off to net income or re-established as accumulated other comprehensive income (loss). Total regulatory assets were $1.543 billion and total regulatory liabilities were $1.032 billion as of December 31, 2016. Refer to Note 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's regulatory assets and liabilities.

Derivatives

PacifiCorp is exposed to the impact of market fluctuations in commodity prices and interest rates. PacifiCorp is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk as it has an obligation to serve retail customer load in its service territories. PacifiCorp's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. Interest rate risk exists on variable-rate debt and future debt issuances. PacifiCorp has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business. PacifiCorp employs a number of different derivative contracts, which may include forwards, options, swaps and other agreements, to manage its commodity price and, at times, interest rate risk. PacifiCorp does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices and interest rates. As of December 31, 2016, PacifiCorp had no derivative contracts outstanding related to interest rate risk. Refer to Notes 11 and 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's derivative contracts.

Measurement Principles

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by accounting principles generally accepted in the United States of America. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which PacifiCorp transacts. When quoted prices for identical contracts are not available, PacifiCorp uses forward price curves. Forward price curves represent PacifiCorp's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. PacifiCorp bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent energy brokers, exchanges, direct communication with market participants and actual transactions executed by PacifiCorp. Market price quotations for certain major electricity and natural gas trading hubs are generally readily obtainable for the first six years; therefore, PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. As of December 31, 2016, PacifiCorp had a net derivative liability of $77 million related to contracts valued using either quoted prices or forward price curves based upon observable market quotes. Market price quotations for other electricity and natural gas trading hubs are not as readily obtainable for the first six years. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, PacifiCorp uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts. The assumptions used in these models are critical because any changes in assumptions could have a significant impact on the estimated fair value of the contracts. As of December 31, 2016, PacifiCorp had a net derivative asset of $- million related to contracts where PacifiCorp uses internal models with significant unobservable inputs.

Classification and Recognition Methodology

PacifiCorp's derivative contracts are probable of inclusion in rates and changes in the estimated fair value of derivative contracts are generally recorded as regulatory assets. Accordingly, amounts are generally not recognized in earnings until the contracts are settled and the forecasted transaction has occurred. As of December 31, 2016, PacifiCorp had $73 million recorded as a regulatory asset related to derivative contracts on the Consolidated Balance Sheets.

Pension and Other Postretirement Benefits

PacifiCorp sponsors defined benefit pension and other postretirement benefit plans that cover the majority of its employees. In addition, PacifiCorp contributes to a joint trustee pension plan for benefits offered to certain bargaining units. PacifiCorp recognizes the funded status of its defined benefit pension and other postretirement benefit plans on the Consolidated Balance Sheets. Funded status is the fair value of plan assets minus the benefit obligation as of the measurement date. As of December 31, 2016, PacifiCorp recognized a net liability totaling $333 million for the funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2016, amounts not yet recognized as a component of net periodic benefit cost that were included in regulatory assets and accumulated other comprehensive loss totaled $525 million and $20 million, respectively.

The expense and benefit obligations relating to these defined benefit pension and other postretirement benefit plans are based on actuarial valuations. Inherent in these valuations are key assumptions, including discount rates and expected long-term rate of return on plan assets. These key assumptions are reviewed annually and modified as appropriate. PacifiCorp believes that the assumptions utilized in recording obligations under the plans are reasonable based on prior plan experience and current market and economic conditions. Refer to Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for disclosures about PacifiCorp's defined benefit pension and other postretirement benefit plans, including the key assumptions used to calculate the funded status and net periodic benefit cost for these plans as of and for the year ended December 31, 2016.

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

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

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

	Pension Plans		Other Postretirement Benefit Plan	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
Effect on December 31, 2016 Benefit Obligations:				
Discount rate	$ (64)	$ 71	$ (15)	$ 17
Effect on 2016 Periodic Cost:				
Discount rate	$ (4)	$ 4	$ —	$ —
Expected rate of return on plan assets	(5)	5	(1)	1

A variety of factors affect the funded status of the plans, including asset returns, discount rates, mortality assumptions, plan changes and PacifiCorp's funding policy for each plan.

Income Taxes

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

PacifiCorp is required to pass income tax benefits and expense related to certain property-related basis differences and other various differences on to its customers. As of December 31, 2016, these amounts were recognized as a regulatory asset of $421 million and a regulatory liability of $9 million and will be included in rates when the temporary differences reverse.

Revenue Recognition - Unbilled Revenue

Revenue is recognized as electricity is delivered or services are provided. The determination of customer billings is based on a systematic reading of meters. At the end of each month, energy provided to customers since the date of the last meter reading is estimated, and the corresponding unbilled revenue is recorded. Unbilled revenue was $275 million as of December 31, 2016. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns, total volumes supplied to the system, line losses, economic impacts and composition of sales among customer classes. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

PacifiCorp's Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. PacifiCorp's significant market risks are primarily associated with commodity prices, interest rates and the extension of credit to counterparties with which PacifiCorp transacts. The following discussion addresses the significant market risks associated with PacifiCorp's business activities. PacifiCorp has established guidelines for credit risk management. Refer to Notes 2 and 11 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's contracts accounted for as derivatives.

Risk Management

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

Risk is an inherent part of PacifiCorp's business and activities. PacifiCorp has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in PacifiCorp's business. The risk management policy governs energy transactions and is designed for hedging PacifiCorp's existing energy and asset exposures, and to a limited extent, the policy permits arbitrage and trading activities to take advantage of market inefficiencies. The policy also governs the types of transactions authorized for use and establishes guidelines for credit risk management and management information systems required to effectively monitor such transactions. PacifiCorp's risk management policy provides for the use of only those contracts that have a similar volume or price relationship to its portfolio of assets, liabilities or anticipated transactions.

Commodity Price Risk

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

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

PacifiCorp's VaR computations utilize several key assumptions. The calculation includes short-term commodity contracts, the expected resource and demand obligations from PacifiCorp's long-term contracts, the expected generation levels from PacifiCorp's generation assets and the expected retail and wholesale load levels. The portfolio reflects flexibility contained in contracts and assets, which accommodate the normal variability in PacifiCorp's demand obligations and generation availability. These contracts and assets are valued to reflect the variability PacifiCorp experiences as a load-serving entity. Contracts or assets that contain flexible elements are often referred to as having embedded options or option characteristics. These options provide for energy volume changes that are sensitive to market price changes. Therefore, changes in the option values affect the energy position of the portfolio with respect to market prices, and this effect is calculated daily. When measuring portfolio exposure through VaR, these position changes that result from the option sensitivity are held constant through the historical simulation. PacifiCorp's VaR methodology is based on a 36-month forward position, 95% confidence interval and one-day holding period.

As of December 31, 2016, PacifiCorp's estimated potential one-day unfavorable impact on fair value of the electricity and natural gas commodity portfolio over the next 36 months was $7 million, as measured by the VaR computations described above. The minimum, average and maximum daily VaR (one-day holding periods) were as follows for the year ended December 31 (in millions):

		2016
Minimum VaR (measured)	$	6
Average VaR (calculated)		8
Maximum VaR (measured)		12

PacifiCorp maintained compliance with its VaR limit procedures during the year ended December 31, 2016. Changes in markets inconsistent with historical trends or assumptions used could cause actual results to exceed estimated VaR levels.

Fair Value of Derivatives

The table that follows summarizes PacifiCorp's price risk on commodity contracts accounted for as derivatives, excluding collateral netting of $69 million and $75 million as of December 31, 2016 and 2015, respectively, and shows the effects of a hypothetical 10% increase and 10% decrease in forward market prices by the expected volumes for these contracts as of that date. The selected hypothetical change does not reflect what could be considered the best or worst case scenarios (dollars in millions):

	Fair Value - Net Asset (Liability)	Estimated Fair Value after Hypothetical Change in Price	
		10% increase	10% decrease
As of December 31, 2016:			
Total commodity derivative contracts	$ (77)	$ (59)	$ (95)
As of December 31, 2015			
Total commodity derivative contracts	$ (136)	$ (103)	$ (169)

PacifiCorp's commodity derivative contracts are generally recoverable from customers in rates; therefore, net unrealized gains and losses associated with interim price movements on commodity derivative contracts do not expose PacifiCorp to earnings volatility. As of December 31, 2016 and 2015, a regulatory asset of $73 million and $133 million, respectively, was recorded related to the net derivative liability of $77 million and $136 million, respectively. Consolidated financial results would be negatively impacted if the costs of wholesale electricity, natural gas or fuel are higher or the level of wholesale electricity sales are lower than what is included in rates, including the impacts of adjustment mechanisms.

Interest Rate Risk

PacifiCorp is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. PacifiCorp manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, PacifiCorp's fixed-rate long-term debt does not expose PacifiCorp to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if PacifiCorp were to reacquire all or a portion of these instruments prior to their maturity. PacifiCorp may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate PacifiCorp's exposure to interest rate risk. The nature and amount of PacifiCorp's short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 6, 7 and 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of PacifiCorp's short- and long-term debt.

As of December 31, 2016 and 2015, PacifiCorp had short- and long-term variable-rate obligations totaling $662 million and $475 million, respectively, that expose PacifiCorp to the risk of increased interest expense in the event of increases in short-term interest rates. The market risk related to PacifiCorp's variable-rate debt as of December 31, 2016 is not hedged. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on PacifiCorp's consolidated annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2016 and 2015.

Credit Risk

PacifiCorp is 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 PacifiCorp's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, PacifiCorp analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, PacifiCorp enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. If required, PacifiCorp exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2016, PacifiCorp's aggregate credit exposure from wholesale activities totaled $136 million, based on settlement and mark-to-market exposures, net of collateral. As of December 31, 2016, $135 million, or 99.6%, of PacifiCorp's credit exposure was with counterparties having investment grade credit ratings by either Moody's Investor Service or Standard & Poor's Rating Services. As of December 31, 2016, two counterparties comprised $87 million, or 64%, of the aggregate credit exposure. The two counterparties are rated investment grade by Moody's Investor Service and Standard & Poor's Rating Services, and PacifiCorp is not aware of any factors that would likely result in a downgrade of the counterparties' credit ratings to below investment grade over the remaining term of transactions outstanding as of December 31, 2016.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
PacifiCorp
Portland, Oregon

We have audited the accompanying consolidated balance sheets of PacifiCorp and subsidiaries ("PacifiCorp") as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive income, changes in shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of PacifiCorp's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. PacifiCorp is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of PacifiCorp's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of PacifiCorp and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 24, 2017

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2016	2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 17	$ 12
Accounts receivable, net	728	740
Income taxes receivable	17	17
Inventories:		
Materials and supplies	228	233
Fuel	215	192
Regulatory assets	53	102
Other current assets	96	81
Total current assets	1,354	1,377
Property, plant and equipment, net	19,162	19,026
Regulatory assets	1,490	1,583
Other assets	388	381
Total assets	$ 22,394	$ 22,367

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

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

	As of December 31, 2016	2015
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 408	$ 473
Accrued employee expenses	67	70
Accrued interest	115	115
Accrued property and other taxes	63	62
Short-term debt	270	20
Current portion of long-term debt and capital lease obligations	58	68
Regulatory liabilities	54	34
Other current liabilities	164	229
Total current liabilities	1,199	1,071
Regulatory liabilities	978	938
Long-term debt and capital lease obligations	7,021	7,078
Deferred income taxes	4,880	4,750
Other long-term liabilities	926	1,027
Total liabilities	15,004	14,864
Commitments and contingencies (Note 13)		
Shareholders' equity:		
Preferred stock	2	2
Common stock - 750 shares authorized, no par value, 357 shares issued and outstanding	—	—
Additional paid-in capital	4,479	4,479
Retained earnings	2,921	3,033
Accumulated other comprehensive loss, net	(12)	(11)
Total shareholders' equity	7,390	7,503
Total liabilities and shareholders' equity	$ 22,394	$ 22,367

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

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

	Years Ended December 31,		
	2016	**2015**	**2014**
Operating revenue	$ 5,201	$ 5,232	$ 5,252
Operating costs and expenses:			
Energy costs	1,751	1,868	1,997
Operations and maintenance	1,064	1,082	1,057
Depreciation and amortization	770	757	726
Taxes, other than income taxes	190	185	172
Total operating costs and expenses	3,775	3,892	3,952
Operating income	1,426	1,340	1,300
Other income (expense):			
Interest expense	(380)	(379)	(379)
Allowance for borrowed funds	15	18	25
Allowance for equity funds	27	33	51
Other, net	15	11	10
Total other income (expense)	(323)	(317)	(293)
Income before income tax expense	1,103	1,023	1,007
Income tax expense	340	328	309
Net income	$ 763	$ 695	$ 698

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

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

	Years Ended December 31,		
	2016	2015	2014
Net income	$ 763	$ 695	$ 698
Other comprehensive (loss) income, net of tax —			
Unrecognized amounts on retirement benefits, net of tax of $-, $1 and $(3)	(1)	2	(4)
Comprehensive income	$ 762	$ 697	$ 694

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

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

	Preferred Stock	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Total Shareholders' Equity
Balance, December 31, 2013	$ 2	$ —	$ 4,479	$ 3,315	$ (9)	$ 7,787
Net income	—	—	—	698	—	698
Other comprehensive loss	—	—	—	—	(4)	(4)
Common stock dividends declared	—	—	—	(725)	—	(725)
Balance, December 31, 2014	2	—	4,479	3,288	(13)	7,756
Net income	—	—	—	695	—	695
Other comprehensive income	—	—	—	—	2	2
Common stock dividends declared	—	—	—	(950)	—	(950)
Balance, December 31, 2015	2	—	4,479	3,033	(11)	7,503
Net income	—	—	—	763	—	763
Other comprehensive loss	—	—	—	—	(1)	(1)
Common stock dividends declared	—	—	—	(875)	—	(875)
Balance, December 31, 2016	$ 2	$ —	$ 4,479	$ 2,921	$ (12)	$ 7,390

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

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

	Years Ended December 31,		
	2016	2015	2014
Cash flows from operating activities:			
Net income	$ 763	$ 695	$ 698
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	770	757	726
Allowance for equity funds	(27)	(33)	(51)
Deferred income taxes and amortization of investment tax credits	139	172	297
Changes in regulatory assets and liabilities	122	63	(112)
Other, net	4	6	22
Changes in other operating assets and liabilities:			
Accounts receivable and other assets	(25)	5	5
Derivative collateral, net	6	(47)	(16)
Inventories	(21)	(7)	37
Income taxes	—	116	(155)
Accounts payable and other liabilities	(163)	7	119
Net cash flows from operating activities	1,568	1,734	1,570
Cash flows from investing activities:			
Capital expenditures	(903)	(916)	(1,066)
Other, net	34	(2)	(13)
Net cash flows from investing activities	(869)	(918)	(1,079)
Cash flows from financing activities:			
Proceeds from long-term debt	—	248	422
Repayments of long-term debt and capital lease obligations	(68)	(124)	(238)
Net proceeds from short-term debt	250	—	20
Common stock dividends	(875)	(950)	(725)
Other, net	(1)	(1)	—
Net cash flows from financing activities	(694)	(827)	(521)
Net change in cash and cash equivalents	5	(11)	(30)
Cash and cash equivalents at beginning of period	12	23	53
Cash and cash equivalents at end of period	$ 17	$ 12	$ 23

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

PACIFICORP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Operations

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

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

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

Use of Estimates in Preparation of Financial Statements

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

Accounting for the Effects of Certain Types of Regulation

PacifiCorp prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, PacifiCorp defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in rates occur.

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

Fair Value Measurements

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

Cash Equivalents and Restricted Cash and Investments

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

Investments

Available-for-sale securities are carried at fair value with realized gains and losses, as determined on a specific identification basis, recognized in earnings and unrealized gains and losses recognized in AOCI, net of tax. As of December 31, 2016 and 2015, PacifiCorp had no unrealized gains and losses on available-for-sale securities. Trading securities are carried at fair value with realized and unrealized gains and losses recognized in earnings.

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

Allowance for Doubtful Accounts

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

	2016	2015	2014
Beginning balance	$ 7	$ 7	$ 8
Charged to operating costs and expenses, net	12	10	11
Write-offs, net	(12)	(10)	(12)
Ending balance	$ 7	$ 7	$ 7

Derivatives

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

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

For PacifiCorp's derivative contracts, the settled amount is generally included in rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in rates are recorded as regulatory liabilities or assets. For a derivative contract not probable of inclusion in rates, changes in the fair value are recognized in earnings.

Inventories

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

Property, Plant and Equipment, Net

General

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

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

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

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of property, plant and equipment, is capitalized as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. AFUDC is computed based on guidelines set forth by the Federal Energy Regulatory Commission ("FERC"). After construction is completed, PacifiCorp is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets.

Asset Retirement Obligations

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

Impairment

The Company evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. The impacts of regulation are considered when evaluating the carrying value of regulated assets.

Revenue Recognition

Revenue is recognized as electricity is delivered or services are provided. Revenue recognized includes billed and unbilled amounts. As of December 31, 2016 and 2015, unbilled revenue was $275 million and $245 million, respectively, and is included in accounts receivable, net on the Consolidated Balance Sheets. Rates charged are established by regulators or contractual arrangements.

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

The monthly unbilled revenues of PacifiCorp are determined by the estimation of unbilled energy provided during the period, the assignment of unbilled energy provided to customer classes and the average rate per customer class. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns, total volumes supplied to the system, line losses, economic impacts and composition of sales among customer classes.

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

Income Taxes

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

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using estimated income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities that are associated with components of OCI are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities that are associated with income tax benefits and expense for certain property-related basis differences and other various differences that PacifiCorp is required to pass on to its customers are charged or credited directly to a regulatory asset or liability. These amounts were recognized as regulatory assets of $421 million and $437 million as of December 31, 2016 and 2015, respectively, and regulatory liabilities of $9 million and $12 million as of December 31, 2016 and 2015, respectively, and will be included in rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more likely than not to be realized.

Investment tax credits are generally deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory jurisdictions. Investment tax credits are included in other long-term liabilities on the Consolidated Balance Sheets and were $18 million and $23 million as of December 31, 2016 and 2015, respectively.

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

Segment Information

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

New Accounting Pronouncements

In November 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-18, which amends FASB Accounting Standards Codification ("ASC") Subtopic 230-10, “Statement of Cash Flows - Overall.” The amendments in this guidance require that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. PacifiCorp is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In August 2016, the FASB issued ASU No. 2016-15, which amends FASB ASC Topic 230, "Statement of Cash Flows." The amendments in this guidance address the classification of eight specific cash flow issues within the statement of cash flows with the objective of reducing the existing diversity in practice. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. PacifiCorp is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements.

In February 2016, the FASB issued ASU No. 2016-02, which creates FASB ASC Topic 842, "Leases" and supersedes Topic 840 "Leases." This guidance increases transparency and comparability among entities by recording lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. A lessee should recognize in the balance sheet a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from previous guidance. This guidance is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted, and is required to be adopted using a modified retrospective approach. PacifiCorp 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 2016, the FASB issued ASU No. 2016-01, which amends FASB ASC Subtopic 825-10, "Financial Instruments - Overall." The amendments in this guidance address certain aspects of recognition, measurement, presentation and disclosure of financial instruments including a requirement that all investments in equity securities that do not qualify for equity method accounting or result in consolidation of the investee be measured at fair value with changes in fair value recognized in net income. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption not permitted, and is required to be adopted prospectively by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. The impact of this update is immaterial to PacifiCorp's 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. During 2016, the FASB issued several ASUs that clarify the implementation guidance for ASU No. 2014-09 but do not change the core principle of the guidance. This guidance may be adopted retrospectively or under a modified retrospective method where the cumulative effect is recognized at the date of initial application. PacifiCorp is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements. PacifiCorp currently does not expect the timing and amount of revenue currently recognized to be materially different after adoption of the new guidance as a majority of revenue is recognized equal to what PacifiCorp has the right to invoice as it corresponds directly with the value to the customer of PacifiCorp’s performance to date. PacifiCorp’s current plan is to quantitatively disaggregate revenue in the required financial statement footnote by customer class and jurisdiction.

(3) Property, Plant and Equipment, Net

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

	Depreciable Life	2016	2015
Property, plant and equipment:			
Generation	14 - 67 years	$ 12,371	$ 12,164
Transmission	58 - 75 years	6,055	5,914
Distribution	20 - 70 years	6,590	6,408
Intangible plant[1]	5 - 62 years	884	875
Other	5 - 60 years	1,398	1,396
Property, plant and equipment in-service		27,298	26,757
Accumulated depreciation and amortization		(8,793)	(8,360)
Net property, plant and equipment in-service		18,505	18,397
Construction work-in-progress		657	629
Total property, plant and equipment, net		$ 19,162	$ 19,026

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

The average depreciation and amortization rate applied to depreciable property, plant and equipment was 2.9%, 2.9% and 3.0% for the years ended December 31, 2016, 2015 and 2014, respectively.

Unallocated Acquisition Adjustments

PacifiCorp has unallocated acquisition adjustments that represent the excess of costs of the acquired interests in property, plant and equipment purchased from the entity that first devoted the assets to utility service over their net book value in those assets. These unallocated acquisition adjustments included in other property, plant and equipment had an original cost of $156 million and $155 million as of December 31, 2016 and 2015, respectively, and accumulated depreciation of $117 million and $112 million as of December 31, 2016 and 2015, respectively.

(4) Jointly Owned Utility Facilities

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

The amounts shown in the table below represent PacifiCorp's share in each jointly owned facility as of December 31, 2016 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 - 4	67%	$ 1,420	$ 583	$ 10
Hunter No. 1	94	473	161	1
Hunter No. 2	60	296	98	—
Wyodak	80	467	203	1
Colstrip Nos. 3 and 4	10	244	130	5
Hermiston	50	178	76	2
Craig Nos. 1 and 2	19	325	223	32
Hayden No. 1	25	74	32	—
Hayden No. 2	13	43	20	—
Foote Creek	79	39	25	—
Transmission and distribution facilities	Various	777	228	61
Total		$ 4,336	$ 1,779	$ 112

(5) Regulatory Matters

Regulatory Assets

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

	Weighted Average Remaining Life	2016	2015
Deferred income taxes[1]	26 years	$ 421	$ 437
Employee benefit plans[2]	21 years	525	499
Utah mine disposition[3]	Various	166	186
Unamortized contract values	7 years	98	110
Deferred net power costs	1 year	33	86
Unrealized loss on derivative contracts	5 years	73	133
Asset retirement obligation	20 years	82	65
Other	Various	145	169
Total regulatory assets		$ 1,543	$ 1,685
Reflected as:			
Current assets		$ 53	$ 102
Noncurrent assets		1,490	1,583
Total regulatory assets		$ 1,543	$ 1,685

(1) Amounts primarily represent income tax benefits and expense related to certain property-related basis differences and other various items that PacifiCorp is required to pass on to its customers.

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

(3) Amounts represent regulatory assets established as a result of the Utah mine disposition discussed below for the net property, plant and equipment not considered probable of disallowance and for the portion of losses associated with the assets held for sale, UMWA 1974 Pension Plan withdrawal and closure costs incurred to date considered probable of recovery.

PacifiCorp had regulatory assets not earning a return on investment of $1.019 billion and $1.102 billion as of December 31, 2016 and 2015, respectively.

Regulatory Liabilities

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

	Weighted Average Remaining Life	2016		2015	
Cost of removal[1]	26 years	$	917	$	894
Deferred income taxes	Various		9		12
Other	Various		106		66
Total regulatory liabilities		$	1,032	$	972
Reflected as:					
Current liabilities		$	54	$	34
Noncurrent liabilities			978		938
Total regulatory liabilities		$	1,032	$	972

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

Utah Mine Disposition

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 2015, PacifiCorp received approval from the commissions.

In December 2014, PacifiCorp filed an advice letter with the California Public Utility Commission ("CPUC") to request approval to sell certain Utah mining assets and to establish memorandum accounts to track the costs associated with the Utah Mine Disposition for future recovery. In July 2015, the CPUC Energy Division issued a letter requiring PacifiCorp to file a formal application for approval of the sale of certain Utah mining assets. Accordingly, in September 2015, PacifiCorp filed an application with the CPUC. On February 6, 2017, a joint motion was filed with the CPUC seeking approval of a settlement agreement reached by PacifiCorp and all other parties. The agreement states, among other things, that the decision to sell certain Utah mining assets is in the public interest. Parties also reserve their rights to additional testimony, briefs, and hearings to the extent the CPUC determines that additional California Environmental Quality Act proceedings are necessary. A CPUC decision on the joint motion and settlement agreement is expected in 2017.

(6) Short-term Debt and Other Financing Agreements

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

2016:		
Credit facilities	$	1,000
Less:		
Short-term debt		(270)
Tax-exempt bond support		(142)
Net credit facilities	$	588
2015:		
Credit facilities	$	1,200
Less:		
Short-term debt		(20)
Tax-exempt bond support and letters of credit		(160)
Net credit facilities	$	1,020

PacifiCorp has a $600 million unsecured credit facility expiring in March 2018 and a $400 million unsecured credit facility with a stated maturity of June 2019 and which has two one-year extension options subject to bank consent. These credit facilities, which support PacifiCorp's commercial paper program, certain series of its tax-exempt bond obligations and provide for the issuance of letters of credit, have a variable interest rate based on the London Interbank Offered Rate or a base rate, at PacifiCorp's option, plus a spread that varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities. As of December 31, 2016 and 2015, the weighted average interest rate on commercial paper borrowings outstanding was 0.96% and 0.65%, respectively. These credit facilities require that PacifiCorp's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter. As of December 31, 2016, PacifiCorp was in compliance with the covenants of its credit facilities.

As of December 31, 2016 and 2015, PacifiCorp had $255 million and $310 million, respectively, of fully available letters of credit issued under committed arrangements, of which $10 million as of December 31, 2015 were issued under the credit facilities. These letters of credit support PacifiCorp's variable-rate tax-exempt bond obligations and expire through March 2019.

As of December 31, 2016, PacifiCorp had approximately $14 million of additional letters of credit issued on its behalf to provide credit support for certain transactions as required by third parties. These letters of credit were all undrawn as of December 31, 2016 and have provisions that automatically extend the annual expiration dates for an additional year unless the issuing bank elects not to renew a letter of credit prior to the expiration date.

(7) Long-term Debt and Capital Lease Obligations

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

	2016			2015	
	Principal Amount	Carrying Value	Average Interest Rate	Carrying Value	Average Interest Rate
First mortgage bonds:					
3.85% to 8.53%, due through 2021	$ 1,272	$ 1,269	5.10%	$ 1,271	5.10%
2.95% to 8.27%, due 2022 to 2026	1,829	1,820	4.10	1,819	4.10
7.70% due 2031	300	298	7.70	298	7.70
5.25% to 6.10%, due 2034 to 2036	850	843	5.80	843	5.80
5.75% to 6.35%, due 2037 to 2039	2,150	2,134	6.00	2,133	6.00
4.10% due 2042	300	297	4.10	297	4.10
Variable-rate series, tax-exempt bond obligations (2016-0.69% to 0.86%; 2015-0.01% to 0.22%):					
Due 2017 to 2018	91	91	0.85	91	0.22
Due 2018 to 2025(1)	108	108	0.74	107	0.01
Due 2024(1)(2)	143	142	0.70	196	0.02
Due 2024 to 2025 (2)	50	50	0.80	59	0.21
Total long-term debt	7,093	7,052		7,114	
Capital lease obligations:					
8.75% to 14.61%, due through 2035	27	27	11.09	32	11.25
Total long-term debt and capital lease obligations	$ 7,120	$ 7,079		$ 7,146	

Reflected as:

	2016	2015
Current portion of long-term debt and capital lease obligations	$ 58	$ 68
Long-term debt and capital lease obligations	7,021	7,078
Total long-term debt and capital lease obligations	$ 7,079	$ 7,146

1) Supported by $255 million and $310 million of fully available letters of credit issued under committed bank arrangements as of December 31, 2016 and 2015, respectively.

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

PacifiCorp's long-term debt generally includes provisions that allow PacifiCorp to redeem the first mortgage bonds in whole or in part at any time through the payment of a make-whole premium. Variable-rate tax-exempt bond obligations are generally redeemable at par value.

PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional $1.325 billion of long-term debt. PacifiCorp must make a notice filing with the Washington Utilities and Transportation Commission prior to any future issuance. PacifiCorp currently has an effective shelf registration statement filed with the United States Securities and Exchange Commission to issue up to $1.325 billion additional first mortgage bonds through January 2019.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $26 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2016.

PacifiCorp has entered into long-term agreements that qualify as capital leases and expire at various dates through March 2035 for transportation services, a power purchase agreement and real estate. The transportation services agreements included as capital leases are for the right to use pipeline facilities to provide natural gas to two of PacifiCorp's generating facilities. Net capital lease assets of $27 million and $32 million as of December 31, 2016 and 2015, respectively, were included in property, plant and equipment, net in the Consolidated Balance Sheets.

As of December 31, 2016, the annual principal maturities of long-term debt and total capital lease obligations for 2017 and thereafter are as follows (in millions):

	Long-term Debt	Capital Lease Obligations	Total
2017	$ 52	$ 9	$ 61
2018	586	4	590
2019	350	4	354
2020	38	3	41
2021	420	6	426
Thereafter	5,647	20	5,667
Total	7,093	46	7,139
Unamortized discount and debt issuance costs	(41)	—	(41)
Amounts representing interest	—	(19)	(19)
Total	$ 7,052	$ 27	$ 7,079

(8) Income Taxes

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

	2016	2015	2014
Current:			
Federal	$ 169	$ 130	$ 2
State	32	26	10
Total	201	156	12
Deferred:			
Federal	123	148	260
State	21	29	43
Total	144	177	303
Investment tax credits	(5)	(5)	(6)
Total income tax expense	$ 340	$ 328	$ 309

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

	2016	2015	2014
Federal statutory income tax rate	35%	35%	35%
State income taxes, net of federal income tax benefit	3	3	3
Federal income tax credits	(6)	(6)	(7)
Other	(1)	—	—
Effective income tax rate	31%	32%	31%

Income tax credits relate primarily to production tax credits earned by PacifiCorp's wind-powered generating facilities. 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.

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

	2016	2015
Deferred income tax assets:		
Regulatory liabilities	$ 393	$ 374
Employee benefits	202	189
Derivative contracts and unamortized contract values	67	94
State carryforwards	69	68
Loss contingencies	12	67
Asset retirement obligations	78	81
Other	82	88
	903	961
Deferred income tax liabilities:		
Property, plant and equipment	(5,161)	(5,030)
Regulatory assets	(586)	(639)
Other	(36)	(42)
	(5,783)	(5,711)
Net deferred income tax liability	$ (4,880)	$ (4,750)

The following table provides PacifiCorp's net operating loss and tax credit carryforwards and expiration dates as of December 31, 2016 (in millions):

	State
Net operating loss carryforwards	$ 1,415
Deferred income taxes on net operating loss carryforwards	$ 52
Expiration dates	2017 - 2032
Tax credit carryforwards	$ 17
Expiration dates	2017 - indefinite

The United States Internal Revenue Service has closed its examination of PacifiCorp's income tax returns through December 31, 2009. The statute of limitations for PacifiCorp's state income tax returns have expired through December 31, 2009, with the exception of California, Oregon and Utah, for which the statute of limitations have expired through March 31, 2006.

As of December 31, 2016 and 2015, PacifiCorp had unrecognized tax benefits totaling $12 million and $13 million, respectively, related to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect PacifiCorp's effective income tax rate.

(9) Employee Benefit Plans

PacifiCorp sponsors defined benefit pension and other postretirement benefit plans that cover the majority of its employees, as well as a defined contribution 401(k) employee savings plan ("401(k) Plan"). In addition, PacifiCorp contributes to a joint trustee pension plan and a subsidiary previously contributed to a multiemployer pension plan for benefits offered to certain bargaining units.

Pension and Other Postretirement Benefit Plans

PacifiCorp's pension plans include non-contributory defined benefit pension plans, collectively the PacifiCorp Retirement Plan ("Retirement Plan"), and the Supplemental Executive Retirement Plan ("SERP"). The Retirement Plan is closed to all non-union employees hired after January 1, 2008. All non-union Retirement Plan participants hired prior to January 1, 2008 that did not elect to receive equivalent fixed contributions to the 401(k) Plan effective January 1, 2009 earned benefits based on a cash balance formula through December 31, 2016. Effective January 1, 2017, non-union employee participants with a cash balance benefit in the Retirement Plan are no longer eligible to receive pay credits in their cash balance formula. In general for union employees, benefits under the Retirement Plan were frozen at various dates from December 31, 2007 through December 31, 2011 as they are now being provided with enhanced 401(k) Plan benefits. However, certain limited union Retirement Plan participants continue to earn benefits under the Retirement Plan based on the employee's years of service and a final average pay formula. The SERP was closed to new participants as of March 21, 2006 and froze future accruals for active participants as of December 31, 2014.

PacifiCorp's other postretirement benefit plan provides healthcare and life insurance benefits to eligible retirees.

Utah Mine Disposition and Labor Agreement

In conjunction with the Utah Mine Disposition described in Note 5, in December 2014, PacifiCorp's subsidiary, 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. No curtailment accounting was triggered as a result of the settlement due to an insignificant impact to the average remaining service lives in the plan.

As a result of the closure of the Deer Creek mining operations, withdrawal from the UMWA 1974 Pension Plan was involuntarily triggered in June 2015 when UMWA employees ceased performing work for the subsidiary. Refer to "Multiemployer and Joint Trustee Pension Plans" for further information regarding the withdrawal.

Net Periodic Benefit Cost

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

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

	Pension			Other Postretirement		
	2016	2015	2014	2016	2015	2014
Service cost	$ 4	$ 4	$ 5	$ 2	$ 3	$ 6
Interest cost	54	53	57	15	16	28
Expected return on plan assets	(75)	(77)	(76)	(21)	(23)	(31)
Net amortization	34	42	29	(5)	(4)	2
Net periodic benefit cost (credit)	$ 17	$ 22	$ 15	$ (9)	$ (8)	$ 5

Funded Status

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

	Pension		Other Postretirement	
	2016	2015	2016	2015
Plan assets at fair value, beginning of year	$ 1,043	$ 1,146	$ 305	$ 482
Employer contributions	5	4	1	1
Participant contributions	—	—	6	6
Actual return on plan assets	51	—	17	1
Settlement	—	—	—	(150)
Benefits paid	(100)	(107)	(27)	(35)
Plan assets at fair value, end of year	$ 999	$ 1,043	$ 302	$ 305

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

	Pension		Other Postretirement	
	2016	2015	2016	2015
Benefit obligation, beginning of year	$ 1,289	$ 1,378	$ 362	$ 539
Service cost	4	4	2	3
Interest cost	54	53	15	16
Participant contributions	—	—	6	6
Actuarial (gain) loss	29	(39)	—	(17)
Settlement	—	—	—	(150)
Benefits paid	(100)	(107)	(27)	(35)
Benefit obligation, end of year	$ 1,276	$ 1,289	$ 358	$ 362
Accumulated benefit obligation, end of year	$ 1,276	$ 1,289		

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

	Pension		Other Postretirement	
	2016	2015	2016	2015
Plan assets at fair value, end of year	$ 999	$ 1,043	$ 302	$ 305
Less - Benefit obligation, end of year	1,276	1,289	358	362
Funded status	$ (277)	$ (246)	$ (56)	$ (57)
Amounts recognized on the Consolidated Balance Sheets:				
Other current liabilities	$ (5)	$ (4)	$ —	$ —
Other long-term liabilities	(272)	(242)	(56)	(57)
Amounts recognized	$ (277)	$ (246)	$ (56)	$ (57)

The SERP has no plan assets; however, PacifiCorp has a Rabbi trust that holds corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERP. The cash surrender value of all of the policies included in the Rabbi trust, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was $55 million and $52 million as of December 31, 2016 and 2015, respectively. These assets are not included in the plan assets in the above table, but are reflected in noncurrent other assets on the Consolidated Balance Sheets.

Unrecognized Amounts

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

	Pension		Other Postretirement	
	2016	2015	2016	2015
Net loss	$ 518	$ 508	$ 39	$ 36
Prior service credit	—	(13)	(13)	(19)
Regulatory deferrals	(7)	(3)	8	9
Total	$ 511	$ 492	$ 34	$ 26

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2016 and 2015 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss	Total
Pension			
Balance, December 31, 2014	$ 474	$ 22	$ 496
Net loss (gain) arising during the year	40	(2)	38
Net amortization	(41)	(1)	(42)
Total	(1)	(3)	(4)
Balance, December 31, 2015	473	19	492
Net loss arising during the year	51	2	53
Net amortization	(33)	(1)	(34)
Total	18	1	19
Balance, December 31, 2016	$ 491	$ 20	$ 511

	Regulatory Asset
Other Postretirement	
Balance, December 31, 2014	$ 17
Net loss arising during the year	5
Net amortization	4
Total	9
Balance, December 31, 2015	26
Net loss arising during the year	3
Net amortization	5
Total	8
Balance, December 31, 2016	$ 34

The net loss, prior service credit and regulatory deferrals that will be amortized in 2017 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Credit	Regulatory Deferrals	Total
Pension	$ 16	$ —	$ (2)	$ 14
Other postretirement	—	(7)	1	(6)
Total	$ 16	$ (7)	$ (1)	$ 8

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2016	2015	2014	2016	2015	2014
Benefit obligations as of December 31:						
Discount rate	4.05%	4.40%	4.00%	4.05%	4.35%	3.90%
Rate of compensation increase	N/A	2.75	2.75	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	4.40%	4.00%	4.80%	4.35%	3.99%	4.90%
Expected return on plan assets	7.50	7.50	7.50	7.50	7.08	7.50
Rate of compensation increase	2.75	2.75	3.00	N/A	N/A	N/A

In establishing its assumption as to the expected return on plan assets, PacifiCorp utilizes the asset allocation and return assumptions for each asset class based on historical performance and forward-looking views of the financial markets. As discussed above in "Utah Mine Disposition and Labor Agreement," PacifiCorp remeasured the other postretirement plan assets and benefit obligation as of May 31, 2015. The other postretirement assumptions for the year ended December 31, 2015 presented above reflect a weighted average calculation that considered the assumptions used in the periods preceding and subsequent to the remeasurement.

As a result of a plan amendment effective on January 1, 2017, the benefit obligation for the Retirement Plan is no longer affected by future increases in compensation. As a result of the labor settlement discussed above in "Utah Mine Disposition and Labor Agreement," the benefit obligation for the other postretirement plan is no longer affected by healthcare cost trends.

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $5 million and $- million, respectively, during 2017. Funding to PacifiCorp's Retirement Plan trust is based upon the actuarially determined costs of the plan and the requirements of the Internal Revenue Code, the Employee Retirement Income Security Act of 1974 ("ERISA") and the Pension Protection Act of 2006, as amended ("PPA"). PacifiCorp considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the PPA. PacifiCorp's funding policy for its other postretirement benefit plan is to generally contribute an amount equal to the net periodic benefit cost, subject to tax deductibility limitations and other considerations.

The expected benefit payments to participants in PacifiCorp's pension and other postretirement benefit plans for 2017 through 2021 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2017	$ 105	$ 28
2018	109	28
2019	108	27
2020	104	30
2021	97	26
2022-2026	426	116

Plan Assets

Investment Policy and Asset Allocations

PacifiCorp's investment policy for its pension and other postretirement benefit plans is to balance risk and return through a diversified portfolio of debt securities, equity securities and other alternative investments. Maturities for debt securities are managed to targets consistent with prudent risk tolerances. The plans retain outside investment advisors to manage plan investments within the parameters outlined by the PacifiCorp Pension Committee. The investment portfolio is managed in line with the investment policy with sufficient liquidity to meet near-term benefit payments.

The target allocations (percentage of plan assets) for PacifiCorp's pension and other postretirement benefit plan assets are as follows as of December 31, 2016:

	Pension(1)	Other Postretirement(1)
	%	%
Debt securities(2)	33 - 37	33 - 37
Equity securities(2)	53 - 57	61 - 65
Limited partnership interests	8 - 12	1 - 3
Other	0 - 1	0 - 1

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

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

Fair Value Measurements

PacifiCorp adopted ASU No. 2015-07, "Fair Value Measurement (Topic 820) - Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share (or its Equivalent)" effective January 1, 2016 under a retrospective method.

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

	Input Levels for Fair Value Measurements			
	Level 1[(1)]	Level 2[(1)]	Level 3[(1)]	Total
As of December 31, 2016:				
Cash equivalents	$ —	$ 10	$ —	$ 10
Debt securities:				
United States government obligations	25	—	—	25
Corporate obligations	—	36	—	36
Municipal obligations	—	6	—	6
Agency, asset and mortgage-backed obligations	—	37	—	37
Equity securities:				
United States companies	389	—	—	389
International companies	15	—	—	15
Investment funds[(2)]	83	—	—	83
Total assets in the fair value hierarchy	$ 512	$ 89	$ —	601
Investment funds[(2)] measured at net asset value				337
Limited partnership interests[(3)] measured at net asset value				61
Investments at fair value				$ 999
As of December 31, 2015:				
Cash equivalents	$ —	$ 10	$ —	$ 10
Debt securities:				
United States government obligations	19	—	—	19
Corporate obligations	—	42	—	42
Municipal obligations	—	5	—	5
Agency, asset and mortgage-backed obligations	—	43	—	43
Equity securities:				
United States companies	408	—	—	408
International companies	17	—	—	17
Investment funds[(2)]	83	—	—	83
Total assets in the fair value hierarchy	$ 527	$ 100	$ —	627
Investment funds[(2)] measured at net asset value				351
Limited partnership interests[(3)] measured at net asset value				65
Investments at fair value				$ 1,043

(1) Refer to Note 12 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are substantially comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 54% and 46% respectively, for 2016 and 53% and 47%, respectively, for 2015, and are invested in United States and international securities of approximately 39% and 61%, respectively, for 2016 and 40% and 60%, respectively, for 2015.

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

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

	Input Levels for Fair Value Measurements			
	Level 1[(1)]	Level 2[(1)]	Level 3[(1)]	Total
As of December 31, 2016:				
Cash and cash equivalents	$ 4	$ 1	$ —	$ 5
Debt securities:				
United States government obligations	11	—	—	11
Corporate obligations	—	13	—	13
Municipal obligations	—	2	—	2
Agency, asset and mortgage-backed obligations	—	13	—	13
Equity securities:				
United States companies	93	—	—	93
International companies	4	—	—	4
Investment funds[(2)]	32	—	—	32
Total assets in the fair value hierarchy	$ 144	$ 29	$ —	173
Investment funds[(2)] measured at net asset value				125
Limited partnership interests[(3)] measured at net asset value				4
Investments at fair value				$ 302
As of December 31, 2015:				
Cash and cash equivalents	$ 4	$ 1	$ —	$ 5
Debt securities:				
United States government obligations	9	—	—	9
Corporate obligations	—	15	—	15
Municipal obligations	—	1	—	1
Agency, asset and mortgage-backed obligations	—	14	—	14
Equity securities:				
United States companies	95	—	—	95
International companies	4	—	—	4
Investment funds[(2)]	32	—	—	32
Total assets in the fair value hierarchy	$ 144	$ 31	$ —	175
Investment funds[(2)] measured at net asset value				126
Limited partnership interests[(3)] measured at net asset value				4
Investments at fair value				$ 305

(1) Refer to Note 12 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are substantially comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 62% and 38%, respectively, for 2016 and 61% and 39%, respectively, for 2015, and are invested in United States and international securities of approximately 71% and 29%, respectively, for 2016 and 67% and 33%, respectively, for 2015.

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

For level 1 investments, 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. For level 2 investments, the fair value is determined using pricing models based on observable market inputs. Shares of mutual funds not registered under the Securities Act of 1933, private equity limited partnership interests, common and commingled trust funds and investment entities are reported at fair value based on the net asset value per unit, which is used for expedience purposes. A fund’s net asset value is based on the fair value of the underlying assets held by the fund less its liabilities.

Multiemployer and Joint Trustee Pension Plans

PacifiCorp contributes to the PacifiCorp/IBEW Local 57 Retirement Trust Fund ("Local 57 Trust Fund") (plan number 001) and its subsidiary, Energy West Mining Company, previously contributed to the UMWA 1974 Pension Plan (plan number 002). Contributions to these pension plans are based on the terms of collective bargaining agreements.

As a result of the Utah Mine Disposition and UMWA labor settlement, PacifiCorp's subsidiary, Energy West Mining Company, triggered involuntary withdrawal from the UMWA 1974 Pension Plan in June 2015 when the UMWA employees ceased performing work for the subsidiary. PacifiCorp recorded its estimate of the withdrawal obligation in December 2014 when withdrawal was considered probable and deferred the portion of the obligation considered probable of recovery to a regulatory asset. PacifiCorp has subsequently revised its estimate due to changes in facts and circumstances for a withdrawal occurring by July 2015. As communicated in a letter received in August 2016, the plan trustees have determined a withdrawal liability of $115 million. Energy West Mining Company began making installment payments in November 2016 and has the option to elect a lump sum payment to settle the withdrawal obligation. The ultimate amount paid by Energy West Mining Company to settle the obligation is dependent on a variety of factors, including the results of ongoing negotiations with the plan trustees.

The Local 57 Trust Fund is a joint trustee plan such that the board of trustees is represented by an equal number of trustees from PacifiCorp and the union. The Local 57 Trust Fund was established pursuant to the provisions of the Taft-Hartley Act and although formed with the ability for other employers to participate in the plan, there are no other employers that participate in this plan.

The risk of participating in multiemployer pension plans generally differs from single-employer plans in that assets are pooled such that contributions by one employer may be used to provide benefits to employees of other participating employers and plan assets cannot revert back to employers. If an employer ceases participation in the plan, the employer may be obligated to pay a withdrawal liability based on the participants' unfunded, vested benefits in the plan. This occurred as a result of Energy West Mining Company's withdrawal from the UMWA 1974 Pension Plan. If participating employers withdraw from a multiemployer plan, the unfunded obligations of the plan may be borne by the remaining participating employers, including any employers that withdrew during the three years prior to a mass withdrawal.

The following table presents PacifiCorp's and Energy West Mining Company's participation in individually significant joint trustee and multiemployer pension plans for the years ended December 31 (dollars in millions):

		PPA zone status or plan funded status percentage for plan years beginning July 1,					Contributions(1)			
Plan name	Employer Identification Number	2016	2015	2014	Funding improvement plan	Surcharge imposed under PPA (1)	2016	2015	2014	Year contributions to plan exceeded more than 5% of total contributions(2)
UMWA 1974 Pension Plan	52-1050282	Critical and Declining	Critical and Declining	Critical	Implemented	Yes	$ —	$ 1	$ 2	None
Local 57 Trust Fund	87-0640888	At least 80%	At least 80%	At least 80%	None	None	$ 8	$ 8	$ 9	2015, 2014, 2013

(1) PacifiCorp's and Energy West Mining Company's minimum contributions to the plans are based on the amount of wages paid to employees covered by the Local 57 Trust Fund collective bargaining agreements and the number of mining hours worked for the UMWA 1974 Pension Plan, respectively, subject to ERISA minimum funding requirements. As a result of the plan's critical status, Energy West Mining Company was required to begin paying a surcharge for hours worked on and after December 1, 2014.

(2) For the UMWA 1974 Pension Plan, information is for plan years beginning July 1, 2014, 2013 and 2012. Information for the plan year beginning July 1, 2015 is not yet available. For the Local 57 Trust Fund, information is for plan years beginning July 1, 2014, 2013 and 2012. Information for the plan year beginning July 1, 2015 is not yet available.

The current collective bargaining agreements governing the Local 57 Trust Fund expire in 2020.

Defined Contribution Plan

PacifiCorp's 401(k) plan covers substantially all employees. PacifiCorp's matching contributions are based on each participant's level of contribution and, as of January 1, 2017, all participants receive contributions based on eligible pre-tax annual compensation. Contributions cannot exceed the maximum allowable for tax purposes. PacifiCorp's contributions to the 401(k) plan were $34 million, $35 million and $34 million for the years ended December 31, 2016, 2015 and 2014, respectively.

(10) Asset Retirement Obligations

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

PacifiCorp does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Consolidated Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. Cost of removal regulatory liabilities totaled $917 million and $894 million as of December 31, 2016 and 2015, respectively.

The following table reconciles the beginning and ending balances of PacifiCorp's ARO liabilities for the years ended December 31 (in millions):

	2016	2015
Beginning balance	$ 224	$ 135
Change in estimated costs	2	62
Additions	—	30
Retirements	(19)	(10)
Accretion	8	7
Ending balance	$ 215	$ 224
Reflected as:		
Other current liabilities	$ 21	$ 35
Other long-term liabilities	194	189
	$ 215	$ 224

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

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. The final rule substantially impacted existing AROs reflected in the December 31, 2015 change in estimated costs above and also resulted in the recognition of additional AROs.

(11) Risk Management and Hedging Activities

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

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

There have been no significant changes in PacifiCorp's accounting policies related to derivatives. Refer to Notes 2 and 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 PacifiCorp's derivative contracts, on a gross basis, and reconciles those amounts to the amounts presented on a net basis on the Consolidated Balance Sheets (in millions):

	Other Current Assets	Other Assets	Other Current Liabilities	Other Long-term Liabilities	Total
As of December 31, 2016:					
Not designated as hedging contracts[1]:					
Commodity assets	$ 24	$ 2	$ 1	$ —	$ 27
Commodity liabilities	(6)	—	(14)	(84)	(104)
Total	18	2	(13)	(84)	(77)
Total derivatives	18	2	(13)	(84)	(77)
Cash collateral receivable	—	—	10	59	69
Total derivatives - net basis	$ 18	$ 2	$ (3)	$ (25)	$ (8)
As of December 31, 2015:					
Not designated as hedging contracts[1]:					
Commodity assets	$ 10	$ —	$ 2	$ —	$ 12
Commodity liabilities	(1)	—	(58)	(89)	(148)
Total	9	—	(56)	(89)	(136)
Total derivatives	9	—	(56)	(89)	(136)
Cash collateral receivable	—	—	18	57	75
Total derivatives - net basis	$ 9	$ —	$ (38)	$ (32)	$ (61)

(1) PacifiCorp's commodity derivatives are generally included in rates and as of December 31, 2016 and 2015, a regulatory asset of $73 million and $133 million, respectively, was recorded related to the net derivative liability of $77 million and $136 million, respectively.

The following table reconciles the beginning and ending balances of PacifiCorp's regulatory assets and summarizes the pre-tax gains and losses on commodity derivative contracts recognized in regulatory assets, as well as amounts reclassified to earnings for the years ended December 31 (in millions):

	2016	2015	2014
Beginning balance	$ 133	$ 85	$ 55
Changes in fair value recognized in regulatory assets	(27)	82	45
Net gains reclassified to operating revenue	10	40	(4)
Net losses reclassified to energy costs	(43)	(74)	(11)
Ending balance	$ 73	$ 133	$ 85

Derivative Contract Volumes

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

	Unit of Measure	2016	2015
Electricity (sales) purchases	Megawatt hours	(3)	1
Natural gas purchases	Decatherms	84	111
Fuel oil purchases	Gallons	11	11

Credit Risk

PacifiCorp is 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 PacifiCorp's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, PacifiCorp analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, PacifiCorp enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. If required, PacifiCorp exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Collateral and Contingent Features

In accordance with industry practice, certain 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" in the event of a material adverse change in PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2016, PacifiCorp's credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of PacifiCorp's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $97 million and $142 million as of December 31, 2016 and 2015, respectively, for which PacifiCorp had posted collateral of $69 million and $75 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 December 31, 2016 and 2015, PacifiCorp would have been required to post $22 million and $64 million, respectively, of additional collateral. PacifiCorp's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation or other factors.

(12) Fair Value Measurements

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

- Level 1 - Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that PacifiCorp has the ability to access at the measurement date.

- Level 2 - Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).

- Level 3 - Unobservable inputs reflect PacifiCorp's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. PacifiCorp develops these inputs based on the best information available, including its own data.

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

	Input Levels for Fair Value Measurements				
	Level 1	Level 2	Level 3	Other(1)	Total
As of December 31, 2016:					
Assets:					
Commodity derivatives	$ —	$ 27	$ —	$ (7)	$ 20
Money market mutual funds(2)	13	—	—	—	13
Investment funds	17	—	—	—	17
	$ 30	$ 27	$ —	$ (7)	$ 50
Liabilities - Commodity derivatives	$ —	$ (104)	$ —	$ 76	$ (28)
As of December 31, 2015:					
Assets:					
Commodity derivatives	$ —	$ 9	$ 3	$ (3)	$ 9
Money market mutual funds (2)	13	—	—	—	13
Investment funds	15	—	—	—	15
	$ 28	$ 9	$ 3	$ (3)	$ 37
Liabilities - Commodity derivatives	$ —	$ (148)	$ —	$ 78	$ (70)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $69 million and $75 million as of December 31, 2016 and 2015, respectively.

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

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

PacifiCorp's investments in money market mutual funds and investment funds are stated at fair value and are primarily accounted for as available-for-sale securities. When available, PacifiCorp uses a readily observable quoted market price or net asset value of an identical security in an active market 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.

PacifiCorp's long-term debt is carried at cost on the Consolidated Balance Sheets. The fair value of PacifiCorp'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 PacifiCorp's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of PacifiCorp's long-term debt as of December 31 (in millions):

	2016		2015	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 7,052	$ 8,204	$ 7,114	$ 8,210

(13) Commitments and Contingencies

Legal Matters

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

Environmental Laws and Regulations

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

Hydroelectric Relicensing

PacifiCorp's Klamath hydroelectric system is currently operating under annual licenses with the FERC. In February 2010, PacifiCorp, the United States Department of the Interior, the United States Department of Commerce, the state of California, the state of Oregon and various other governmental and non-governmental settlement parties signed the Klamath Hydroelectric Settlement Agreement ("KHSA"). Among other things, the KHSA provided that the United States Department of the Interior would conduct scientific and engineering studies to assess whether removal of the Klamath hydroelectric system's mainstem dams was in the public interest and would advance restoration of the Klamath Basin's salmonid fisheries. If it was determined that dam removal should proceed, dam removal would begin no earlier than 2020.

Congress failed to pass legislation needed to implement the original KHSA. Hence, in February 2016, the principal parties to the KHSA (PacifiCorp, the states of California and Oregon and the United States Departments of the Interior and Commerce) executed an agreement in principle committing to explore potential amendment of the KHSA to facilitate removal of the Klamath dams through a FERC process without the need for federal legislation. On April 6, 2016, PacifiCorp, the states of California and Oregon, and the United States Departments of the Interior and Commerce and other stakeholders executed an amendment to the KHSA. Consistent with the terms of the amended KHSA, on September 23, 2016, PacifiCorp and the Klamath River Renewal Corporation ("KRRC") jointly filed an application with the FERC to transfer the license for the four mainstem Klamath River hydroelectric generating facilities from PacifiCorp to the KRRC. Also on September 23, 2016, the KRRC filed an application with the FERC to surrender the license and decommission the facilities. The KRRC's license surrender application included a request for the FERC to refrain from acting on the surrender application until after the transfer of the license to the KRRC is effective.

Under the amended KHSA, PacifiCorp and its customers continue to be protected from uncapped dam removal costs and liabilities. The KRRC must indemnify PacifiCorp from liabilities associated with dam removal. The amended KHSA also limits PacifiCorp's contribution to facilities removal costs to no more than $200 million, of which up to $184 million would be collected from PacifiCorp's Oregon customers with the remainder to be collected from PacifiCorp's California customers. California voters approved a water bond measure in November 2014 from which the state of California's contribution towards facilities removal costs will be drawn. In accordance with this bond measure, additional funding of up to $250 million for facilities removal costs was included in the California state budget in 2016, with the funding effective for at least five years. If facilities removal costs exceed the combined funding that will be available from PacifiCorp's Oregon and California customers and the state of California, sufficient funds would need to be provided by the KRRC or an entity other than PacifiCorp in order for removal to proceed.

If certain conditions in the amended KHSA are not satisfied and the license does not transfer to the KRRC, PacifiCorp will resume relicensing with the FERC.

As of December 31, 2016, PacifiCorp's assets included $68 million of costs associated with the Klamath hydroelectric system's mainstem dams and the associated relicensing and settlement costs, which are being depreciated and amortized in accordance with state regulatory approvals through either December 31, 2019, or December 31, 2022, depending upon the state jurisdiction.

Hydroelectric Commitments

Certain of PacifiCorp's hydroelectric licenses contain requirements for PacifiCorp to make certain capital and operating expenditures related to its hydroelectric facilities. PacifiCorp estimates it is obligated to make capital expenditures of approximately $227 million over the next 10 years related to these licenses.

Commitments

PacifiCorp has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2016 are as follows (in millions):

	2017	2018	2019	2020	2021	2022 and Thereafter	Total
Contract type:							
Purchased electricity contracts - commercially operable	$ 253	$ 160	$ 157	$ 157	$ 145	$ 1,630	$ 2,502
Purchased electricity contracts - non-commercially operable	10	13	17	17	18	390	465
Fuel contracts	796	616	596	507	346	1,407	4,268
Construction commitments	62	46	26	4	1	4	143
Transmission	109	106	90	61	47	467	880
Operating leases and easements	5	5	5	5	4	39	63
Maintenance, service and other contracts	53	29	31	17	20	68	218
Total commitments	$ 1,288	$ 975	$ 922	$ 768	$ 581	$ 4,005	$ 8,539

Purchased Electricity Contracts - Commercially Operable

As part of its energy resource portfolio, PacifiCorp acquires a portion of its electricity through long-term purchases and exchange agreements. PacifiCorp has several power purchase agreements with wind-powered generating facilities that are not included in the table above as the payments are based on the amount of energy generated and there are no minimum payments. Included in the purchased electricity payments are any power purchase agreements that meet the definition of a lease. Rent expense related to those power purchase agreements that meet the definition of a lease totaled $14 million for 2016, $13 million for 2015 and $15 million for 2014.

Included in the minimum fixed annual payments for purchased electricity above are commitments to purchase electricity from several hydroelectric systems under long-term arrangements with public utility districts. These purchases are made on a "cost-of-service" basis for a stated percentage of system output and for a like percentage of system operating expenses and debt service. These costs are included in energy costs on the Consolidated Statements of Operations. PacifiCorp is required to pay its portion of operating costs and its portion of the debt service, whether or not any electricity is produced. These arrangements accounted for less than 5% of PacifiCorp's 2016, 2015 and 2014 energy sources.

Purchased Electricity Contracts - Non-commercially Operable

PacifiCorp has several contracts for purchases of electricity from facilities that have not yet achieved commercial operation. To the extent any of these facilities do not achieve commercial operation, PacifiCorp has no obligation to the counterparty.

Fuel Contracts

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

Construction Commitments

PacifiCorp's construction commitments included in the table above relate to firm commitments and include costs associated with investments in emissions control equipment and certain transmission and distribution projects.

Transmission

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

Operating Leases and Easements

PacifiCorp has non-cancelable operating leases primarily for certain operating facilities, office space, land and equipment that expire at various dates through the year ending December 31, 2092. These leases generally require PacifiCorp to pay for insurance, taxes and maintenance applicable to the leased property. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. PacifiCorp also has non-cancelable easements for land on which its wind-powered generating facilities are located. Rent expense totaled $15 million for the years ended December 31, 2016 and 2015, and $16 million for 2014.

Guarantees

PacifiCorp 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 PacifiCorp's consolidated financial results.

(14) Preferred Stock

PacifiCorp has 3,500 thousand shares of Serial Preferred Stock authorized at the stated value of $100 per share. PacifiCorp had 24 thousand shares of Serial Preferred Stock issued and outstanding as of December 31, 2016 and 2015. The outstanding preferred stock series are non-redeemable and have annual dividend rates of 6.00% and 7.00%.

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

PacifiCorp also has 16 million shares of No Par Serial Preferred Stock and 127 thousand shares of 5% Preferred Stock authorized, but no shares were issued or outstanding as of December 31, 2016 and 2015.

(15) Common Shareholder's Equity

In February 2017, PacifiCorp declared a dividend of $100 million payable to PPW Holdings LLC, a wholly owned subsidiary of BHE and PacifiCorp's direct parent company ("PPW Holdings") in March 2017.

Through PPW Holdings, BHE is the sole shareholder of PacifiCorp's common stock. The state regulatory orders that authorized BHE's acquisition of PacifiCorp contain restrictions on PacifiCorp's ability to pay dividends to the extent that they would reduce PacifiCorp's common equity below specified percentages of defined capitalization. As of December 31, 2016, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings or BHE without prior state regulatory approval to the extent that it would reduce PacifiCorp's common equity below 44% of its total capitalization, excluding short-term debt and current maturities of long-term debt. The terms of this commitment treat 50% of PacifiCorp's remaining balance of preferred stock in existence prior to the acquisition of PacifiCorp by BHE as common equity. As of December 31, 2016, PacifiCorp's actual common equity percentage, as calculated under this measure, was 51%, and PacifiCorp would have been permitted to dividend $1.9 billion under this commitment.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings or BHE if PacifiCorp's senior unsecured debt rating is BBB- or lower by Standard & Poor's Rating Services or Fitch Ratings or Baa3 or lower by Moody's Investor Service, as indicated by two of the three rating services. As of December 31, 2016, PacifiCorp met the minimum required senior unsecured debt ratings for making distributions.

PacifiCorp is also subject to a maximum debt-to-total capitalization percentage under various financing agreements as further discussed in Note 6.

(16) Components of Accumulated Other Comprehensive Loss, Net

Accumulated other comprehensive loss, net consists of unrecognized amounts on retirement benefits, net of tax, of $12 million and $11 million as of December 31, 2016 and 2015, respectively.

(17) Variable-Interest Entities

PacifiCorp holds an undivided interest in 50% of the Hermiston generating facility (refer to Note 4). Prior to the expiration of a power purchase agreement in July 2016, PacifiCorp dictated when the generating facility operated, procured 100% of the natural gas for the generating facility and subsequently received 100% of the generated electricity, 50% of which was acquired through a power purchase agreement that expired. As a result, PacifiCorp held a variable interest in the joint owner of the remaining 50% of the facility and was the primary beneficiary. With the expiration of the power purchase agreement, PacifiCorp no longer holds a variable interest in the joint owner. PacifiCorp was unable to obtain the information necessary to previously consolidate the entity because the entity did not supply the information due to the lack of a contractual obligation to do so. Cost of the electricity purchased from the joint owner was $20 million, $39 million and $38 million during each of the years ended December 31, 2016, 2015 and 2014, respectively. The entity is operated by the equity owners and PacifiCorp has no risk of loss in relation to the entity in the event of a disaster.

PacifiCorp holds a two-thirds interest in Bridger Coal Company ("Bridger Coal"), which supplies coal to the Jim Bridger generating facility that is owned two-thirds by PacifiCorp and one-third by PacifiCorp's joint venture partner in Bridger Coal. PacifiCorp purchases two-thirds of the coal produced by Bridger Coal, while the remaining coal is purchased by the joint venture partner. The power to direct the activities that most significantly impact Bridger Coal's economic performance are shared with the joint venture partner. Each joint venture partner is jointly and severally liable for the obligations of Bridger Coal. Bridger Coal's necessary working capital to carry out its mining operations is financed by contributions from PacifiCorp and its joint venture partner. PacifiCorp's equity investment in Bridger Coal was $165 million and $190 million as of December 31, 2016 and 2015, respectively. Refer to Note 18 for information regarding related-party transactions with Bridger Coal.

(18) Related-Party Transactions

PacifiCorp has an intercompany administrative services agreement with BHE and its subsidiaries. Amounts charged to PacifiCorp by BHE and its subsidiaries under this agreement totaled $10 million during each of the years ended December 31, 2016, 2015 2014, respectively. Payables associated with these administrative services were $2 million as of December 31, 2016 and 2015, respectively. Amounts charged by PacifiCorp to BHE and its subsidiaries under this agreement totaled $4 million, $7 million and $10 million during the years ended December 31, 2016, 2015 and 2014, respectively. Receivables associated with these administrative services were $1 million as of December 31, 2016 and 2015, respectively.

PacifiCorp also engages in various transactions with several subsidiaries of BHE in the ordinary course of business. Services provided by these subsidiaries in the ordinary course of business and charged to PacifiCorp primarily relate to wholesale electricity purchases and transmission of electricity, transportation of natural gas and employee relocation services. These expenses totaled $7 million, $8 million and $7 million during the years ended December 31, 2016, 2015 and 2014, respectively. Payables associated with these services were $1 million as of December 31, 2016 and 2015, respectively. Amounts charged by PacifiCorp to subsidiaries of BHE for wholesale electricity sales in the ordinary course of business totaled $1 million, $2 million and $5 million during the years ended December 31, 2016, 2015 and 2014, respectively.

PacifiCorp has long-term transportation contracts with BNSF Railway Company ("BNSF"), an indirect wholly owned subsidiary of Berkshire Hathaway, PacifiCorp's ultimate parent company. Transportation costs under these contracts were $37 million during the year ended December 31, 2016 and $39 million during the years ended December 31, 2015 and 2014. As of December 31, 2016 and 2015, PacifiCorp had $1 million, respectively, of accounts payable to BNSF outstanding under these contracts, including indirect payables related to a jointly owned facility.

PacifiCorp participated in a captive insurance program provided by MEHC Insurance Services Ltd. ("MEISL"), a wholly owned subsidiary of BHE. MEISL covered all or significant portions of the property damage and liability insurance deductibles in many of PacifiCorp's policies, as well as overhead distribution and transmission line property damage. The policy coverage period expired on March 20, 2011 and was not renewed. Proceeds from claims were $- million, $2 million and $- million during the years ended December 31, 2016, 2015 and 2014, respectively.

PacifiCorp is party to a tax-sharing agreement and is part of the Berkshire Hathaway United States federal income tax return. Federal and state income taxes receivable from BHE were $17 million as of December 31, 2016 and 2015, respectively. For the years ended December 31, 2016, 2015 and 2014, cash paid for federal and state income taxes to BHE totaled $201 million, $40 million and $161 million, respectively.

PacifiCorp transacts with its equity investees, Bridger Coal and Trapper Mining Inc. During the years ended December 31, 2016, 2015 and 2014, PacifiCorp charged Bridger Coal $2 million, $19 million and $3 million, respectively, primarily for the sale of mining equipment in 2015, administrative support and management services, as well as materials, provided by PacifiCorp to Bridger Coal. Receivables for these services, as well as for certain expenses paid by PacifiCorp and reimbursed by Bridger Coal, were $5 million and $4 million as of December 31, 2016 and 2015, respectively. Services provided by equity investees to PacifiCorp primarily relate to coal purchases. During the years ended December 31, 2016, 2015 and 2014, coal purchases from PacifiCorp's equity investees totaled $174 million, $181 million and $146 million, respectively. Payables to PacifiCorp's equity investees were $17 million and $16 million as of December 31, 2016 and 2015, respectively.

(19) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2016	2015	2014
Interest paid, net of amounts capitalized	$ 350	$ 342	$ 340
Income taxes paid, net	$ 201	$ 40	$ 161
Supplemental disclosure of non-cash investing and financing activities:			
Accounts payable related to property, plant and equipment additions	$ 101	$ 147	$ 140
Accounts receivable related to property, plant and equipment sales	$ —	$ 40	$ —

MidAmerican Funding, LLC and its subsidiaries and MidAmerican Energy Company
Consolidated Financial Section

Item 6. Selected Financial Data

Information required by Item 6 is omitted pursuant to General Instruction I(2)(a) to Form 10-K.

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

General

MidAmerican Funding is an Iowa limited liability company whose sole member is BHE. MidAmerican Funding owns all of the outstanding common stock of MHC, which owns all of the common stock of MidAmerican Energy, Midwest Capital and MEC Construction. MHC, MidAmerican Funding and BHE are headquartered in Des Moines, Iowa.

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of MidAmerican Funding and its subsidiaries and MidAmerican Energy as presented in this joint filing. Information in Management's Discussion and Analysis related to MidAmerican Energy, whether or not segregated, also relates to MidAmerican Funding. Information related to other subsidiaries of MidAmerican Funding pertains only to the discussion of the financial condition and results of operations of MidAmerican Funding. Where necessary, discussions have been segregated under the heading "MidAmerican Funding" to allow the reader to identify information applicable only to MidAmerican Funding. 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 historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. MidAmerican Energy's and MidAmerican Funding's actual results in the future could differ significantly from the historical results.

Results of Operations

Overview

MidAmerican Energy -

MidAmerican Energy's income from continuing operations for 2016 was $542 million, an increase of $96 million, or 22%, compared to 2015 due to higher electric margins of $172 million, higher production tax credits of $39 million and lower fossil-fueled generation operations and maintenance of $35 million, partially offset by higher depreciation and amortization of $72 million from wind-powered generation and other plant placed in service and an accrual related to an Iowa revenue sharing arrangement, higher operations costs recovered through bill riders of $20 million, higher interest expense of $13 million primarily due to the issuance of first mortgage bonds in October 2015 and a lower income tax benefit due to higher pre-tax income and the effects of ratemaking. Electric margins reflect higher retail rates in Iowa, higher retail sales volumes, lower energy costs, higher wholesale revenue and higher transmission revenue.

MidAmerican Energy's income from continuing operations for 2015 was $446 million, an increase of $45 million, or 11%, compared to 2014 due to higher regulated electric margins of $119 million, higher production tax credits of $27 million and lower fossil-fueled generation maintenance of $10 million, partially offset by higher depreciation and amortization of $56 million due to wind-powered generation and other plant placed in-service, lower AFUDC of $27 million, lower regulated natural gas margins of $12 million due to warmer temperatures in 2015 and higher interest expense of $9 million due to the issuance of first mortgage bonds in April 2014 and October 2015, net of the effect of a related redemption of senior notes in May 2014. Regulated electric margins increased primarily due to higher retail rates in Iowa and changes in rate structure related to seasonal pricing, lower purchased power costs, a lower average cost of fuel for generation and higher transmission revenue, partially offset by lower wholesale revenue.

MidAmerican Funding -

MidAmerican Funding's income from continuing operations for 2016 was $532 million, an increase of $90 million, or 20%, compared to $442 million for 2015. MidAmerican Funding's income from continuing operations for 2015 was $442 million, an increase of $49 million, or 12%, compared to $393 million for 2014. In addition to the changes in MidAmerican Energy's earnings discussed above, MidAmerican Funding recognized an $8 million after-tax gain on the sale of an investment in a generating facility lease in 2015.

Regulated Electric Gross Margin

A comparison of key results related to regulated electric gross margin is as follows for the years ended December 31:

	2016	2015	Change		2015	2014	Change	
Gross margin (in millions):								
Operating revenue	$ 1,985	$ 1,837	$ 148	8 %	$ 1,837	$ 1,817	$ 20	1 %
Cost of fuel, energy and capacity[1]	409	433	(24)	(6)	433	532	(99)	(19)
Gross margin	$ 1,576	$ 1,404	$ 172	12	$ 1,404	$ 1,285	$ 119	9
Sales (GWh):								
Residential	6,408	6,166	242	4 %	6,166	6,429	(263)	(4)%
Commercial	3,812	3,806	6	—	3,806	4,084	(278)	(7)
Industrial	12,115	11,487	628	5	11,487	10,642	845	8
Other	1,589	1,583	6	—	1,583	1,622	(39)	(2)
Total retail	23,924	23,042	882	4	23,042	22,777	265	1
Wholesale	8,489	8,741	(252)	(3)	8,741	9,716	(975)	(10)
Total sales	32,413	31,783	630	2	31,783	32,493	(710)	(2)
Average number of retail customers (in thousands)	760	752	8	1 %	752	746	6	1 %
Average revenue per MWh:								
Retail	$ 71.86	$ 69.68	$ 2.18	3 %	$ 69.68	$ 66.92	$ 2.76	4 %
Wholesale	$ 22.95	$ 20.09	$ 2.86	14 %	$ 20.09	$ 26.48	$ (6.39)	(24)%
Heating degree days	5,321	5,654	(333)	(6)%	5,654	6,899	(1,245)	(18)%
Cooling degree days	1,314	1,067	247	23 %	1,067	933	134	14 %
Sources of energy (GWh)[2]:								
Coal	13,179	15,525	(2,346)	(15)%	15,525	18,234	(2,709)	(15)%
Nuclear	3,912	3,885	27	1	3,885	3,842	43	1
Natural gas	556	199	357	*	199	114	85	75
Wind and other[3]	11,684	9,606	2,078	22	9,606	7,965	1,641	21
Total energy generated	29,331	29,215	116	—	29,215	30,155	(940)	(3)
Energy purchased	3,882	3,194	688	22	3,194	3,029	165	5
Total	33,213	32,409	804	2	32,409	33,184	(775)	(2)

* Not meaningful.

(1) Effective in August 2014, MidAmerican Energy is allowed to recover fluctuations in electric energy costs for its Iowa retail electric generation through an energy adjustment mechanism.

(2) GWh amounts are net of energy used by the related generating facilities.

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

For 2016 compared to 2015, regulated electric gross margin increased $172 million primarily due to:

(1) Higher retail gross margin of $118 million due to -

- an increase of $47 million from higher electric rates in Iowa effective January 1, 2016, for the third step of a 2014 Iowa rate increase;
- an increase of $33 million primarily from non-weather-related usage factors, including higher industrial sales volumes;
- an increase of $27 million from the impact of temperatures;
- an increase of $13 million from lower retail energy costs due to a lower average cost of fuel for generation and lower coal-fueled generation; partially offset by
- a decrease of $2 million from lower recoveries through bill riders;

(2) Higher wholesale gross margin of $37 million due to higher margins per unit from greater availability of lower cost generation for wholesale purposes, partially offset by lower sales volumes attributable to lower coal-fueled generation; and

(3) Higher MVP transmission revenue of $17 million, which is expected to increase as projects are constructed.

For 2015 compared to 2014, regulated electric gross margin increased $119 million as follows:

(1) Higher retail gross margin of $109 million due to -

- an increase of $70 million from higher electric rates, reflecting higher rates of $45 million annually, effective January 2015, for the second step of a 2014 Iowa rate increase, $16 million annually in Illinois, effective December 2014, and an increase from the full-year impact of changes in Iowa rate structure related to seasonal pricing, which were effective with the implementation of final Iowa base rates in August 2014 that resulted in a greater differential between summer rates from June to September and rates in the remaining months;
- an increase of $32 million from lower retail energy costs primarily due to a lower average cost of fuel for generation and lower purchased power costs;
- an increase of $11 million from non-weather-related usage factors;
- an increase of $8 million principally from higher recoveries through bill riders; and
- a decrease of $8 million from the impact of temperatures;

(2) Higher MVP transmission revenue of $25 million, which is expected to increase as projects are constructed; partially offset by

(3) Lower wholesale gross margin of $15 million due to decreases of -

- $9 million from lower sales volumes; and
- $6 million from lower average prices.

Regulated Gas Gross Margin

A comparison of key results related to regulated gas gross margin is as follows for the years ended December 31:

	2016	2015	Change		2015	2014	Change	
Gross margin (in millions):								
Operating revenue	$ 637	$ 661	$ (24)	(4)%	$ 661	$ 996	$ (335)	(34)%
Cost of gas sold	367	397	(30)	(8)	397	720	(323)	(45)
Gross margin	$ 270	$ 264	$ 6	2	$ 264	$ 276	$ (12)	(4)
Natural gas throughput (000's Dths):								
Residential	46,020	46,519	(499)	(1)%	46,519	56,224	(9,705)	(17)%
Commercial	23,345	23,466	(121)	(1)	23,466	28,256	(4,790)	(17)
Industrial	5,079	4,833	246	5	4,833	5,335	(502)	(9)
Other	37	37	—	—	37	48	(11)	(23)
Total retail sales	74,481	74,855	(374)	—	74,855	89,863	(15,008)	(17)
Wholesale sales	38,813	35,250	3,563	10	35,250	25,346	9,904	39
Total sales	113,294	110,105	3,189	3	110,105	115,209	(5,104)	(4)
Gas transportation service	83,610	80,001	3,609	5	80,001	82,314	(2,313)	(3)
Total gas throughput	196,904	190,106	6,798	4	190,106	197,523	(7,417)	(4)
Average number of retail customers (in thousands)	742	733	9	1 %	733	726	7	1 %
Average revenue per retail Dth sold	$ 6.85	$ 7.12	$ (0.27)	(4)%	$ 7.12	$ 9.24	$ (2.12)	(23)%
Average cost of natural gas per retail Dth sold	$ 3.70	$ 4.03	$ (0.33)	(8)%	$ 4.03	$ 6.54	$ (2.51)	(38)%
Combined retail and wholesale average cost of natural gas per Dth sold	$ 3.24	$ 3.61	$ (0.37)	(10)%	$ 3.61	$ 6.25	$ (2.64)	(42)%
Heating degree days	5,616	5,913	(297)	(5)%	5,913	7,209	(1,296)	(18)%

Regulated gas revenue includes PGAs through which MidAmerican Energy is allowed to recover the cost of gas sold from its retail gas utility customers. Consequently, fluctuations in the cost of gas sold do not directly affect gross margin or net income because regulated gas revenue reflects comparable fluctuations through the PGAs. For 2016, MidAmerican Energy's combined retail and wholesale average per-unit cost of gas sold decreased 10%, resulting in a decrease of $42 million in gas revenue and cost of gas sold compared to 2015. For 2015, MidAmerican Energy's combined retail and wholesale average per-unit cost of gas sold decreased 42%, resulting in a decrease of $290 million in gas revenue and cost of gas sold compared to 2014. Additionally, fluctuations in gas wholesale sales impact gas revenue and cost of gas sold but do not affect regulated gas gross margin.

For 2016 compared to 2015, regulated gas gross margin increased $6 million due to higher DSM recoveries. Lower retail sales volumes due to warmer winter temperatures in 2016 reduced gas gross margin by $3 million but was substantially offset by higher sales volumes from non-weather-related usage factors and higher transportation revenue.

For 2015 compared to 2014, regulated gas gross margin decreased $12 million primarily due to $20 million from lower retail sales volumes reflecting warmer winter temperatures in 2015; partially offset by $7 million from an increase due to non-weather-related usage factors.

Regulated Operating Costs and Expenses

Operations and maintenance decreased $12 million for 2016 compared to 2015 due to $24 million of lower fossil-fueled generation maintenance from the timing of planned outages, $7 million of lower generation operations, $7 million of lower health care, information technology and other administrative costs and $6 million of lower electric and gas distribution costs, partially offset by $11 million of higher DSM program costs and $9 million of higher transmission operations costs from MISO, both of which are recoverable in bill riders and matched by increases in revenue, and $13 million of higher wind-powered generation maintenance due to the addition of wind turbines.

Operations and maintenance decreased $12 million for 2015 compared to 2014 substantially due to $10 million of lower fossil-fueled generation maintenance costs from planned outages in 2014, $9 million of lower electric distribution costs due to less inclement weather and emergency storm restoration, $8 million for lower expense resulting from a one-time refund in June 2014 to MidAmerican Energy's customers for insurance recoveries related to environmental matters, $4 million of lower pension and postretirement costs and $3 million of lower healthcare benefit costs, partially offset by $10 million of higher wind-powered generation costs due to the addition of facilities and increases in transmission operations costs from MISO and DSM program costs of $7 million and $5 million, respectively, both of which are recoverable in bill riders and matched by increases in revenue.

Depreciation and amortization increased $72 million for 2016 compared to 2015 primarily due to additional wind-powered generating facilities placed in service in the second half of 2015 and the fourth quarter of 2016 and $34 million for accruals for regulatory arrangements in Iowa that reduce electric utility net plant.

Depreciation and amortization increased $56 million for 2015 compared to 2014 primarily due to additional wind-powered generating facilities placed in service in the second half of 2014 and the second half of 2015.

Other Income and (Expense)

MidAmerican Energy -

Interest expense increased $13 million for 2016 compared to 2015 primarily due to higher interest expense from the issuance of $650 million of first mortgage bonds in October 2015, partially offset by the payment of a $426 million turbine purchase obligation in December 2015. Refer to Note 9 of Notes to Financial Statements in Item 8 of this Form 10-K for further discussion of first mortgage bonds.

Interest expense increased $9 million for 2015 compared to 2014 due to higher interest expense from the issuance of first mortgage bonds totaling $850 million in April 2014 and $650 million in October 2015, net of lower interest expense from the redemption of $350 million of 4.65% senior notes in May 2014.

Allowance for borrowed and equity funds decreased $27 million for 2015 compared to 2014 primarily due to lower construction work-in-progress balances related to the installation of emissions control equipment at a number of MidAmerican Energy's jointly owned generating facilities and the construction of wind-powered generating facilities.

Other, net increased $9 million for 2016 compared to 2015 due to a gain of $5 million on the redemption of MidAmerican Energy's investments in auction rate securities and higher returns from corporate-owned life insurance policies. Other, net decreased $5 million for 2015 compared to 2014 due to lower returns from corporate-owned life insurance policies.

MidAmerican Funding -

In addition to the fluctuations discussed above for MidAmerican Energy, MidAmerican Funding's *other, net* for 2016 reflects income of $2 million from a partnership's sale of a real estate investment, for 2015 reflects a $13 million pre-tax gain on the sale of an investment in a generating facility lease and, for 2014, reflects income related to the investment in a generating lease.

Income Tax Benefit

MidAmerican Energy -

MidAmerican Energy's income tax benefit on continuing operations decreased $15 million for 2016 compared to 2015, and the effective tax rate was (32)% for 2016 and (49)% for 2015. The change in the effective tax rate was substantially due to higher pre-tax income, partially offset by an increase of $39 million in production tax credits.

MidAmerican Energy's income tax benefit on continuing operations increased $31 million compared to 2014, and the effective tax rate was (49)% for 2015 and (41)% for 2014. The change in the effective tax rate was due to an increase of $27 million in production tax credits and the effects of ratemaking.

State utility rate regulation in Iowa requires that the tax effect of certain temporary differences be flowed through immediately to customers. Therefore, certain deferred tax amounts that would otherwise have been recognized in income tax expense have been included as changes in regulatory assets in recognition of MidAmerican Energy's ability to recover increased tax expense when such temporary differences reverse. This treatment of such temporary differences impacts income tax expense and effective income tax rates from year to year.

Federal renewable electricity production tax credits are earned as energy from qualifying wind-powered generating facilities is produced and sold based on a prescribed per-kilowatt rate pursuant to the applicable federal income tax law and are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in service. Beginning in late 2014, some of MidAmerican Energy's wind-powered generating facilities surpassed the 10-year eligibility period and are no longer earning the credits. A credit of $0.023 per kilowatt hour was applied to 2016, 2015 and 2014 production, which resulted in $249 million, $210 million and $183 million, respectively, in production tax credits.

MidAmerican Funding -

MidAmerican Funding's income tax benefit on continuing operations decreased $11 million for 2016 compared to 2015, and the effective tax rate was (35)% for 2016 and (51)% for 2015. MidAmerican Funding's income tax benefit on continuing operations increased $28 million for 2015 compared to 2014, and the effective tax rate was (51)% for 2015 and (45)% for 2014. The change in effective tax rates was due principally to the factors discussed for MidAmerican Energy. Additionally, 2015 reflects income taxes on a $13 million gain from the sale of an investment in a generating facility lease.

Liquidity and Capital Resources

As of December 31, 2016, MidAmerican Energy's total net liquidity was $300 million consisting of $14 million of cash and cash equivalents and $605 million of credit facilities reduced by $220 million of the credit facilities reserved to support MidAmerican Energy's variable-rate tax-exempt bond obligations and $99 million of short-term debt outstanding. As of December 31, 2016, MidAmerican Funding's total net liquidity was $305 million, including MHC's $4 million credit facility.

Cash Flows From Operating Activities

MidAmerican Energy's net cash flows from operating activities were $1.40 billion, $1.35 billion and $823 million for 2016, 2015 and 2014, respectively. MidAmerican Funding's net cash flows from operating activities were $1.39 billion, $1.34 billion and $820 million for 2016, 2015 and 2014, respectively. Cash flows from operating activities increased for 2016 compared to 2015 primarily due to higher gross margins for MidAmerican Energy's regulated electric business, partially offset by a growth in receivables net of payables, lower derivative collateral cash flows, higher payments for asset retirement obligation settlements, and the timing of DSM cost recovery cash flows. The increase in net cash flows from operating activities for 2015 compared to 2014 was primarily due to the timing of MidAmerican Energy's income tax cash flows with BHE, which totaled net cash receipts from BHE of $629 million and $149 million for 2015 and 2014, respectively. Income tax cash flows for 2015 reflect the receipt of $255 million of income tax benefits generated in 2014. The timing of MidAmerican Energy's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods and assumptions for each payment date. Additionally, cash flows from operations for 2015 improved due to higher gross margins for MidAmerican Energy's regulated electric business and lower derivative collateral requirements, partially offset by an increase in coal inventories and lower gross margins for the regulated gas business.

MidAmerican Energy's income tax cash flows benefited in 2015 and 2016 from bonus depreciation on qualifying assets placed in service and from production tax credits earned on qualifying projects as a result of the Tax Increase Prevention Act of 2014 (the "Act"), which was signed into law in December 2014. The Act extended to 2015 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 began construction before the end of 2014.

In December 2015, the Protecting Americans from Tax Hikes Act of 2015 ("PATH") was signed into law, extending bonus depreciation for qualifying property acquired and placed in service before January 1, 2020 (bonus depreciation rates will be 50% for 2015-2017, 40% in 2018, and 30% in 2019), with an additional year for certain longer lived assets. Production tax credits were extended and phased out for wind power and other forms of non-solar renewable energy projects that begin construction before the end of 2019. Production tax credits are maintained at the following levels for projects for which construction begins before the end of the respective year as follows: at full value for 2016, at 80% of present value for 2017, at 60% of present value for 2018, and 40% of present value for 2019. As a result of PATH, MidAmerican Energy's cash flows from operations are expected to benefit due to bonus depreciation on qualifying assets placed in service through 2019 and production tax credits earned on qualifying wind projects through 2029.

Cash Flows From Investing Activities

MidAmerican Energy's net cash flows from investing activities were $(1.62) billion, $(1.45) billion and $(1.52) billion for 2016, 2015 and 2014, respectively. MidAmerican Funding's net cash flows from investing activities were $(1.61) billion, $(1.44) billion and $(1.52) billion for 2016, 2015 and 2014, respectively. Net cash flows from investing activities consist almost entirely of utility construction expenditures, which increased for 2016 compared to 2015 due to higher expenditures for wind-powered generation construction, including a project for the repowering of certain wind-powered generating facilities, partially offset by lower expenditures for MidAmerican Energy's transmission Multi-Value Projects ("MVP") investments. Utility construction expenditures decreased for 2015 compared to 2014 due to lower expenditures for environmental and other generation, partially offset by higher expenditures for wind-powered generation construction and MidAmerican Energy's transmission MVP investments. MidAmerican Energy placed in service 600 MW, 608 MW and 511 MW of wind-powered generating facilities during 2016, 2015 and 2014, respectively. Purchases and proceeds related to available-for-sale securities consist of activity within the Quad Cities Generating Station nuclear decommissioning trust and, in 2016, proceeds from the redemption of MidAmerican Energy's investments in auction rate securities. MidAmerican Funding received $13 million in 2015 related to the sale of an investment in a generating facility lease.

Cash Flows From Financing Activities

MidAmerican Energy's net cash flows from financing activities were $123 million, $173 million and $533 million for 2016, 2015 and 2014, respectively. MidAmerican Funding's net cash flows from financing activities were $133 million, $176 million and $535 million for 2016, 2015 and 2014, respectively. In December 2016, the Iowa Finance Authority issued $30 million of its variable-rate, tax-exempt Solid Waste Facilities Revenue Bonds due December 2046, the proceeds of which were loaned to MidAmerican Energy for the purpose of constructing solid waste facilities. In September 2016, the Iowa Finance Authority issued $33 million of variable-rate, tax-exempt Pollution Control Facilities Refunding Revenue Bonds due September 2036, the proceeds of which were loaned to MidAmerican Energy to refinance, in September 2016, variable-rate tax-exempt pollution control refunding revenue bonds totaling $29 million due September 2016 and $4 million due March 2017, which were optionally redeemed in full. In October 2015, MidAmerican Energy issued $200 million of 3.50% First Mortgage Bonds due October 2024 and $450 million of 4.25% First Mortgage Bonds due May 2046. The net proceeds were used for the payment of a $426 million turbine purchase obligation due December 2015 and for general corporate purposes. In April 2014, MidAmerican Energy issued $150 million of 2.40% First Mortgage Bonds due March 2019, $300 million of 3.50% First Mortgage Bonds due October 2024 and $400 million of 4.40% First Mortgage Bonds due October 2044. The net proceeds were used for the optional redemption in May 2014 of $350 million of MidAmerican Energy's 4.65% Senior Notes due October 2014 and for general corporate purposes. Through its commercial paper program, MidAmerican Energy received $99 million in 2016, made repayments totaling $50 million in 2015 and received $50 million in 2014. MidAmerican Funding received $9 million in 2016, paid $3 million in 2015 and received $1 million in 2014 through its note payable with BHE.

Debt Authorizations and Related Matters

MidAmerican Energy has authority from the FERC to issue commercial paper and bank notes aggregating $605 million through February 28, 2017, and $905 million from March 1, 2017, through February 28, 2019, at interest rates not to exceed the applicable London Interbank Offered Rate ("LIBOR") plus a spread of 400 basis points. MidAmerican Energy has a $600 million unsecured credit facility expiring in March 2018. MidAmerican Energy may request that the banks extend the credit facility up to two years. The credit facility, which supports MidAmerican Energy's commercial paper program and its variable-rate tax-exempt bond obligations and provides for the issuance of letters of credit, has a variable interest rate based on LIBOR or a base rate, at MidAmerican Energy's option, plus a spread that varies based on MidAmerican Energy's credit ratings for senior unsecured long-term debt securities. Additionally, MidAmerican Energy has a $5 million unsecured credit facility for general corporate purposes.

MidAmerican Energy currently has an effective registration statement with the SEC to issue an indeterminate amount of long-term debt securities through September 16, 2018. Additionally, following the February 2017 issuance of $850 million of first mortgage bonds, MidAmerican Energy has authorization from the FERC to issue through March 31, 2017, long-term securities totaling up to $137 million at interest rates not to exceed the applicable United States Treasury rate plus a spread of 175 basis points and from the ICC to issue up to an aggregate of $500 million of additional long-term debt securities, of which $350 million expires March 15, 2018, and $150 million expires September 22, 2018.

In conjunction with the March 1999 merger, MidAmerican Energy committed to the IUB to use commercially reasonable efforts to maintain an investment grade rating on its long-term debt and to maintain its common equity level above 42% of total capitalization unless circumstances beyond its control result in the common equity level decreasing to below 39% of total capitalization. MidAmerican Energy must seek the approval of the IUB of a reasonable utility capital structure if MidAmerican Energy's common equity level decreases below 42% of total capitalization, unless the decrease is beyond the control of MidAmerican Energy. MidAmerican Energy is also required to seek the approval of the IUB if MidAmerican Energy's equity level decreases to below 39%, even if the decrease is due to circumstances beyond the control of MidAmerican Energy. If MidAmerican Energy's common equity level were to drop below the required thresholds, MidAmerican Energy's ability to issue debt could be restricted. As of December 31, 2016, MidAmerican Energy's common equity ratio was 53% computed on a basis consistent with its commitment. As a result of MidAmerican Energy's regulatory commitment to maintain its common equity above certain thresholds, MidAmerican Energy could dividend $2.0 billion as of December 31, 2016, without falling below 42%, and MidAmerican Funding had restricted net assets of $3.1 billion.

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

Future Uses of Cash

MidAmerican Energy and MidAmerican Funding have 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, and other sources. These sources are expected to provide funds required for current operations, capital expenditures, debt retirements and other capital requirements. The availability and terms under which MidAmerican Energy and MidAmerican Funding have access to external financing depends on a variety of factors, including their credit ratings, investors' judgment of risk and conditions in the overall capital markets, including the condition of the utility industry.

Capital Expenditures

MidAmerican Energy's primary need for capital is utility construction expenditures. 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.

MidAmerican Energy's historical and forecast capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, for the years ended December 31 are as follows (in millions):

	Historical			Forecast		
	2014	**2015**	**2016**	**2017**	**2018**	**2019**
Wind-powered generation development	$ 767	$ 931	$ 943	$ 843	$ 880	$ 1,438
Wind-powered generation repowering	—	—	67	292	132	—
Transmission Multi-Value Projects	144	156	119	38	37	—
Other	615	359	507	678	475	341
Total	$ 1,526	$ 1,446	$ 1,636	$ 1,851	$ 1,524	$ 1,779

MidAmerican Energy's historical and forecast capital expenditures include the following:

- The construction of wind-powered generating facilities in Iowa. As of December 31, 2016, MidAmerican Energy had 4,048 MW (nominal ratings) placed in service. In August 2016, the IUB issued an order approving ratemaking principles related to MidAmerican Energy's construction of up to 2,000 MW (nominal ratings) of additional wind-powered generating facilities expected to be placed in service in 2017 through 2019. The ratemaking principles establish a cost cap of $3.6 billion, including AFUDC, and a fixed rate of return on equity of 11.0% over the proposed 40-year useful lives of those facilities in any future Iowa rate proceeding. The cost cap ensures that as long as total costs are below the cap, the investment will be deemed prudent in any future Iowa rate proceeding. Additionally, the ratemaking principles modify the revenue sharing mechanism currently in effect. The revised sharing mechanism will be effective in 2018 and will be triggered each year by actual equity returns exceeding the weighted average return on equity for MidAmerican Energy calculated annually. Pursuant to the change in revenue sharing, MidAmerican Energy will share 100% of the revenue in excess of this trigger with customers. Such revenue sharing will reduce coal and nuclear generation rate base, which is intended to mitigate future base rate increases. MidAmerican Energy expects all of these wind-powered generating facilities to qualify for 100% of federal production tax credits available.
- The repowering of certain existing wind-powered generating facilities in Iowa. This project entails the replacement of significant components of the oldest turbines in MidAmerican Energy's fleet. The energy production from such repowered facilities is expected to qualify for 100% of the federal production tax credits available for ten years following completion.
- Transmission MVP investments. MidAmerican Energy has approval from the MISO for the construction of four MVPs located in Iowa and Illinois totaling approximately $520 million in capital expenditures, excluding non-cash equity AFUDC. When complete, the four MVPs will have added approximately 250 miles of 345 kV transmission line to MidAmerican Energy's transmission system and will be owned and operated by MidAmerican Energy. As of December 31, 2016, MidAmerican Energy has invested $445 million since 2012, excluding non-cash equity AFUDC.
- Remaining expenditures primarily relate to routine operating projects for distribution, generation, transmission and other infrastructure needed to serve existing and expected demand.

Contractual Obligations

MidAmerican Energy and MidAmerican Funding have contractual cash obligations that may affect their financial condition. The following table summarizes the material contractual cash obligations of MidAmerican Energy and MidAmerican Funding as of December 31, 2016 (in millions):

	Payments Due By Periods				
	2017	2018-2019	2020-2021	2022 and After	Total
MidAmerican Energy:					
Long-term debt	$ 251	$ 851	$ 3	$ 3,227	$ 4,332
Interest payments on long-term debt[(1) (2)]	192	321	293	2,150	2,956
Coal, electricity and natural gas contract commitments[(1)]	315	218	75	82	690
Construction commitments[(1)]	347	7	—	—	354
Easements and operating leases[(1)]	20	40	38	624	722
Other commitments[(1)]	72	181	178	210	641
	1,197	1,618	587	6,293	9,695
MidAmerican Funding parent:					
Long-term debt	—	—	—	325	325
Interest payments on long-term debt[(1)]	22	45	45	169	281
	22	45	45	494	606
Total contractual cash obligations	$ 1,219	$ 1,663	$ 632	$ 6,787	$ 10,301

(1) Not reflected on the Consolidated Balance Sheets.

(2) Includes interest payments for tax-exempt bond obligations with interest rates scheduled to reset periodically prior to maturity. Future variable interest rates are assumed to equal December 31, 2016 rates.

MidAmerican Energy has other types of commitments that relate primarily to construction expenditures (in "Utility Construction Expenditures" section above) and asset retirement obligations beyond 2017 (Note 12), which have not been included in the above table because the amount or timing of the cash payments is not certain. Refer to Notes 9, 12 and 15 in Notes to Financial Statements in Item 8 of this Form 10-K for additional information.

Regulatory Matters

MidAmerican Energy is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further discussion regarding MidAmerican Energy's general regulatory framework and current regulatory matters.

Quad Cities Generating Station Operating Status

Exelon Generation Company, LLC ("Exelon Generation"), the operator of Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station") of which MidAmerican Energy has a 25% ownership interest, announced on June 2, 2016, its intention to shut down Quad Cities Station on June 1, 2018, as a result of Illinois not passing adequate legislation and Quad Cities Station not clearing the 2019-2020 PJM Interconnection, L.L.C. capacity auction. MidAmerican Energy expressed to Exelon Generation its desire for the continued operation of the facility through the end of its operating license in 2032 and worked with Exelon Generation on solutions to that end. In December 2016, Illinois passed legislation creating a zero emission standard. The zero emission standard requires the Illinois Power Agency to purchase zero emission credits and recover the costs from certain ratepayers in Illinois, subject to certain limitations. The proceeds from the zero emission credits will provide Exelon Generation additional revenue through 2027 as an incentive for continued operation of Quad Cities Station. For the nuclear assets already in rate base, MidAmerican Energy's customers will not be charged for the subsidy, and MidAmerican Energy will not receive additional revenue from the subsidy.

Environmental Laws and Regulations

MidAmerican Energy is subject to federal, state and local laws and regulations regarding air and water quality, 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 its 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 and local agencies. All such laws and regulations are subject to a range of interpretation, which may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and MidAmerican Energy is unable to predict the impact of the changing laws and regulations on its operations and financial results. MidAmerican Energy believes it is in material compliance with all applicable laws and regulations.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for additional information regarding environmental laws and regulations and "Liquidity and Capital Resources" for MidAmerican Energy's forecast environmental-related capital expenditures.

Collateral and Contingent Features

Debt securities of MidAmerican Energy are rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of MidAmerican Energy's ability to, in general, meet the obligations of its issued debt 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. As of December 31, 2016, MidAmerican Energy's credit ratings for its senior secured debt and its issuer credit ratings for senior unsecured debt from the three recognized credit rating agencies were investment grade. As a result of the issuance of first mortgage bonds by MidAmerican Energy in September 2013, its then outstanding senior unsecured debt was equally and ratably secured with such first mortgage bonds. Refer to Note 9 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K for a discussion of MidAmerican Energy's first mortgage bonds.

MidAmerican Funding and MidAmerican Energy have no credit rating downgrade triggers that would accelerate the maturity dates of its outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments. MidAmerican Energy'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 MidAmerican Energy's collateral requirements on its 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 MidAmerican Energy's creditworthiness. These rights can vary by contract and by counterparty. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of December 31, 2016, MidAmerican Energy would have been required to post $106 million of additional collateral. MidAmerican Energy'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 13 of Notes to Financial Statements in Item 8 of this Form 10-K for a discussion of MidAmerican Energy's collateral requirements specific to its derivative contracts.

Inflation

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

New Accounting Pronouncements

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

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the 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. The following critical accounting estimates are impacted significantly by MidAmerican Energy's methods, judgments and assumptions used in the preparation of the Financial Statements and should be read in conjunction with MidAmerican Energy's Summary of Significant Accounting Policies included in Note 2 of Notes to Financial Statements in Item 8 of this Form 10-K.

Accounting for the Effects of Certain Types of Regulation

MidAmerican Energy prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, MidAmerican Energy defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

MidAmerican Energy continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition, that could limit MidAmerican Energy's ability to recover its costs. MidAmerican Energy believes the application of the guidance for regulated operations is appropriate, and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI"). Total regulatory assets were $1.2 billion and total regulatory liabilities were $883 million as of December 31, 2016. Refer to Note 6 of Notes to Financial Statements in Item 8 of this Form 10-K for additional information regarding regulatory assets and liabilities.

Income Taxes

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

MidAmerican Energy is required to pass income tax benefits related to certain property-related basis differences and other various differences on to its customers in Iowa. These amounts were recognized as a net regulatory asset totaling $985 million as of December 31, 2016, and will be included in regulated rates when the temporary differences reverse.

Impairment of Goodwill

MidAmerican Funding's Consolidated Balance Sheet as of December 31, 2016, includes goodwill from the acquisition of MHC totaling $1.3 billion. Goodwill is allocated to each reporting unit. MidAmerican Funding evaluates goodwill for impairment at least annually and completed its annual review as of October 31. Additionally, no indicators of impairment were identified as of December 31, 2016. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. MidAmerican Funding uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings; and an appropriate discount rate. Estimated future cash flows are impacted by, among other factors, growth rates, changes in regulations and rates, ability to renew contracts and estimates of future commodity prices. In estimating future cash flows, MidAmerican Funding incorporates current market information, as well as historical factors.

Pension and Other Postretirement Benefits

MidAmerican Energy sponsors defined benefit pension and other postretirement benefit plans that cover the majority of the employees of BHE and its domestic energy subsidiaries other than PacifiCorp and NV Energy Inc. MidAmerican Energy recognizes the funded status of its defined benefit pension and other postretirement benefit plans on the Balance Sheets. Funded status is the fair value of plan assets minus the benefit obligation as of the measurement date. As of December 31, 2016, MidAmerican Energy recognized a net liability totaling $70 million for the funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2016, amounts not yet recognized as a component of net periodic benefit cost that were included in regulatory assets and regulatory liabilities totaled $40 million and $12 million, respectively.

The expense and benefit obligations relating to these defined benefit pension and other postretirement benefit plans are based on actuarial valuations. Inherent in these valuations are key assumptions, including discount rates, expected long-term rate of return on plan assets and healthcare cost trend rates. These key assumptions are reviewed annually and modified as appropriate. MidAmerican Energy believes that the assumptions utilized in recording obligations under the plans are reasonable based on prior plan experience and current market and economic conditions. Refer to Note 11 of Notes to Financial Statements in Item 8 of this Form 10-K for disclosures about MidAmerican Energy's defined benefit pension and other postretirement benefit plans, including the key assumptions used to calculate the funded status and net periodic benefit cost for these plans as of and for the year ended December 31, 2016.

MidAmerican Energy chooses a discount rate based upon high quality debt security investment yields in effect as of the measurement date that corresponds to the expected benefit period. The pension and other postretirement benefit liabilities increase as the discount rate is reduced.

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

MidAmerican Energy chooses a healthcare cost trend rate that reflects the near and long-term expectations of increases in medical costs and corresponds to the expected benefit payment periods. The healthcare cost trend rate is assumed to gradually decline to 5% by 2025 at which point the rate of increase is assumed to remain constant. Refer to Note 11 of Notes to Financial Statements in Item 8 of this Form 10-K for healthcare cost trend rate sensitivity disclosures.

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

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
Effect on December 31, 2016 Benefit Obligations:				
Discount rate	$ (36)	$ 40	$ (9)	$ 10
Effect on 2016 Periodic Cost:				
Discount rate	1	(1)	—	—
Expected rate of return on plan assets	(3)	3	(1)	1

A variety of factors affect the funded status of the plans, including asset returns, discount rates, plan changes and MidAmerican Energy's funding policy for each plan.

Revenue Recognition - Unbilled Revenue

Revenue from electric and natural gas customers is recognized as electricity or natural gas is delivered or services are provided. The determination of customer billings is based on a systematic reading of meters and rates. At the end of each month, energy provided to customers since the date of the last meter reading is estimated, and the corresponding unbilled revenue is recorded. Unbilled revenue was $87 million as of December 31, 2016. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns, total volumes supplied to the system, line losses, economic impacts and composition of sales among customer classes. Unbilled revenue is reversed in the following month, and billed revenue is recorded based on the subsequent meter readings.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

MidAmerican Energy's Balance Sheets include assets and liabilities with fair values that are subject to market risks. MidAmerican Energy's significant market risks are primarily associated with commodity prices, interest rates and the extension of credit to counterparties with which it transacts. The following discussion addresses the significant market risks associated with MidAmerican Energy's business activities. MidAmerican Energy has established guidelines for credit risk management. Refer to Notes 2 and 13 of Notes to Financial Statements in Item 8 of this Form 10-K for additional information regarding MidAmerican Energy's contracts accounted for as derivatives.

Commodity Price Risk

MidAmerican Energy is exposed to the impact of market fluctuations in commodity prices and interest rates. MidAmerican Energy is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk as it has an obligation to serve retail customer load in its regulated service territory. 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. Commodity price risk for MidAmerican Energy's regulated retail electricity and natural gas operations is significantly mitigated by the inclusion of energy costs in energy cost rider mechanisms, which permit the current recovery of such costs from its retail customers. MidAmerican Energy uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements to mitigate price volatility on behalf of its customers. MidAmerican Energy does not engage in a material amount of proprietary trading activities, and following the January 1, 2016 transfer of MidAmerican Energy's unregulated retail services business to a subsidiary of BHE, MidAmerican Energy no longer provides nonregulated retail electricity and natural gas services in competitive markets.

Interest Rate Risk

MidAmerican Energy and MidAmerican Funding are exposed to interest rate risk on their outstanding variable-rate short- and long-term debt and future debt issuances. MidAmerican Energy and MidAmerican Funding manage interest rate risk by limiting their exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, the fixed-rate long-term debt does not expose MidAmerican Energy or MidAmerican Funding to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if MidAmerican Energy or MidAmerican Funding were to reacquire all or a portion of these instruments prior to their maturity. MidAmerican Energy or MidAmerican Funding may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate their exposure to interest rate risk. The nature and amount of their short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 8, 9 and 14 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-K for additional discussion of MidAmerican Energy's and MidAmerican Funding's short- and long-term debt.

As of December 31, 2016 and 2015, MidAmerican Energy had short- and long-term variable-rate obligations totaling $319 million and $195 million, respectively, that expose MidAmerican Energy to the risk of increased interest expense in the event of increases in short-term interest rates. The market risk related to MidAmerican Energy's variable-rate debt as of December 31, 2016, is not hedged. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on MidAmerican Energy's annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2016 and 2015.

Credit Risk

MidAmerican Energy is 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. Additionally, MidAmerican Energy participates in the regional transmission organization ("RTO") markets and has indirect credit exposure related to other participants, although RTO credit policies are designed to limit exposure to credit losses from individual participants. Credit risk may be concentrated to the extent MidAmerican Energy's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, MidAmerican Energy analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty, and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, MidAmerican Energy enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. If required, MidAmerican Energy exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Substantially all of MidAmerican Energy's electric wholesale sales revenue results from participation in RTOs, including the MISO and the PJM. MidAmerican Energy's share of historical losses from defaults by other RTO market participants has not been material. Additionally, as of December 31, 2016, MidAmerican Energy's aggregate direct credit exposure from electric wholesale marketing counterparties was not material.

Item 8. Financial Statements and Supplementary Data

MidAmerican Energy Company

MidAmerican Funding, LLC and Subsidiaries

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying balance sheets of MidAmerican Energy Company ("MidAmerican Energy") as of December 31, 2016 and 2015, and the related statements of operations, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2016. Our audits also included MidAmerican Energy's financial statement schedule listed in the Index at Item 15(a)(ii). These financial statements and financial statement schedule are the responsibility of MidAmerican Energy's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. MidAmerican Energy is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of MidAmerican Energy's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of MidAmerican Energy Company as of December 31, 2016 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 3 to the financial statements, MidAmerican Energy transferred its assets and liabilities of its unregulated retail services business to a subsidiary of its parent, Berkshire Hathaway Energy Company, on January 1, 2016.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 24, 2017

MIDAMERICAN ENERGY COMPANY
BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2016	**2015**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 14	$ 103
Receivables, net	285	342
Income taxes receivable	9	104
Inventories	264	238
Other current assets	35	58
Total current assets	607	845
Property, plant and equipment, net	12,821	11,723
Regulatory assets	1,161	1,044
Investments and restricted cash and investments	653	634
Other assets	217	139
Total assets	$ 15,459	$ 14,385

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

MIDAMERICAN ENERGY COMPANY
BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2016	**2015**
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 303	$ 426
Accrued interest	45	46
Accrued property, income and other taxes	137	125
Short-term debt	99	—
Current portion of long-term debt	250	34
Other current liabilities	159	166
Total current liabilities	993	797
Long-term debt	4,051	4,237
Deferred income taxes	3,572	3,061
Regulatory liabilities	883	831
Asset retirement obligations	510	488
Other long-term liabilities	290	266
Total liabilities	10,299	9,680
Commitments and contingencies (Note 15)		
Shareholder's equity:		
Common stock - 350 shares authorized, no par value, 71 shares issued and outstanding	—	—
Additional paid-in capital	561	561
Retained earnings	4,599	4,174
Accumulated other comprehensive loss, net	—	(30)
Total shareholder's equity	5,160	4,705
Total liabilities and shareholder's equity	$ 15,459	$ 14,385

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

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2016	2015	2014
Operating revenue:			
Regulated electric	$ 1,985	$ 1,837	$ 1,817
Regulated gas and other	640	665	1,005
Total operating revenue	2,625	2,502	2,822
Operating costs and expenses:			
Cost of fuel, energy and capacity	409	433	532
Cost of gas sold and other	367	398	720
Operations and maintenance	693	705	717
Depreciation and amortization	479	407	351
Property and other taxes	112	110	108
Total operating costs and expenses	2,060	2,053	2,428
Operating income	565	449	394
Other income and (expense):			
Interest expense	(196)	(183)	(174)
Allowance for borrowed funds	8	8	16
Allowance for equity funds	19	20	39
Other, net	14	5	10
Total other income and (expense)	(155)	(150)	(109)
Income before income tax benefit	410	299	285
Income tax benefit	(132)	(147)	(116)
Income from continuing operations	542	446	401
Discontinued operations (Note 3):			
Income from discontinued operations	—	22	28
Income tax expense	—	6	12
Income on discontinued operations	—	16	16
Net income	$ 542	$ 462	$ 417

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

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2016	**2015**	**2014**
Net income	$ 542	$ 462	$ 417
Other comprehensive income (loss), net of tax:			
Unrealized gains on available-for-sale securities, net of tax of $1, $- and $1	3	—	1
Unrealized losses on cash flow hedges, net of tax of $-, $(4) and $(10)	—	(7)	(13)
Total other comprehensive income (loss), net of tax	3	(7)	(12)
Comprehensive income	$ 545	$ 455	$ 405

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

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF CHANGES IN EQUITY
(Amounts in millions)

	Common Stock	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Total Equity
Balance, December 31, 2013	$ 561	$ 3,295	$ (11)	$ 3,845
Net income	—	417	—	417
Other comprehensive income	—	—	(12)	(12)
Balance, December 31, 2014	561	3,712	(23)	4,250
Net income	—	462	—	462
Other comprehensive loss	—	—	(7)	(7)
Balance, December 31, 2015	561	4,174	(30)	4,705
Net income	—	542	—	542
Other comprehensive loss	—	—	3	3
Dividend (Note 3)	—	(117)	27	(90)
Balance, December 31, 2016	$ 561	$ 4,599	$ —	$ 5,160

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

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2016	**2015**	**2014**
Cash flows from operating activities:			
Net income	$ 542	$ 462	$ 417
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	479	407	351
Deferred income taxes and amortization of investment tax credits	361	275	300
Changes in other assets and liabilities	47	49	47
Other, net	(91)	(58)	(57)
Changes in other operating assets and liabilities:			
Receivables, net	(61)	91	(3)
Inventories	(27)	(53)	44
Derivative collateral, net	5	33	(53)
Contributions to pension and other postretirement benefit plans, net	(6)	(8)	(2)
Accounts payable	39	(76)	30
Accrued property, income and other taxes, net	107	217	(252)
Other current assets and liabilities	8	12	1
Net cash flows from operating activities	1,403	1,351	823
Cash flows from investing activities:			
Utility construction expenditures	(1,636)	(1,446)	(1,526)
Purchases of available-for-sale securities	(138)	(142)	(88)
Proceeds from sales of available-for-sale securities	158	135	80
Proceeds from sales of other investments	—	—	8
Other, net	1	3	5
Net cash flows from investing activities	(1,615)	(1,450)	(1,521)
Cash flows from financing activities:			
Proceeds from long-term debt	62	649	840
Repayments of long-term debt	(38)	(426)	(356)
Net proceeds from (repayments of) short-term debt	99	(50)	50
Other, net	—	—	(1)
Net cash flows from financing activities	123	173	533
Net change in cash and cash equivalents	(89)	74	(165)
Cash and cash equivalents at beginning of year	103	29	194
Cash and cash equivalents at end of year	$ 14	$ 103	$ 29

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

(1) Company Organization

MidAmerican Energy Company ("MidAmerican Energy") is a public utility with electric and natural gas operations and is the principal subsidiary of MHC Inc. ("MHC"). MHC is a holding company that conducts no business other than the ownership of its subsidiaries and related corporate services. MHC's nonregulated subsidiaries include Midwest Capital Group, Inc. and MEC Construction Services Co. MHC is the direct wholly owned subsidiary of MidAmerican Funding, LLC, ("MidAmerican Funding"), which is an Iowa limited liability company with Berkshire Hathaway Energy Company ("BHE") as its sole member. BHE is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Use of Estimates in Preparation of Financial Statements

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

Accounting for the Effects of Certain Types of Regulation

MidAmerican Energy's utility operations are subject to the regulation of the Iowa Utilities Board ("IUB"), the Illinois Commerce Commission ("ICC"), the South Dakota Public Utilities Commission, and the Federal Energy Regulatory Commission ("FERC"). MidAmerican Energy's accounting policies and the accompanying Financial Statements conform to GAAP applicable to rate-regulated enterprises and reflect the effects of the ratemaking process.

MidAmerican Energy prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, MidAmerican Energy defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

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

Fair Value Measurements

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

Cash Equivalents and Restricted Cash and Investments

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

Investments

MidAmerican Energy's management determines the appropriate classification of investments in debt and equity securities at the acquisition date and reevaluates the classification at each balance sheet date. Investments that management does not intend to use or is restricted from using in current operations are presented as noncurrent on the Balance Sheets.

Available-for-sale securities are carried at fair value with realized gains and losses, as determined on a specific identification basis, recognized in earnings and unrealized gains and losses recognized in AOCI, net of tax. Realized and unrealized gains and losses on securities in a trust related to the decommissioning of the Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station") are recorded as a net regulatory liability because MidAmerican Energy expects to recover costs for these activities through regulated rates. Held-to-maturity securities are carried at amortized cost, reflecting the ability and intent to hold the securities to maturity.

Investments gains and losses arise when investments are sold (as determined on a specific identification basis) or are other-than-temporarily impaired. If a decline in value of an investment below cost is deemed other than temporary, the cost of the investment is written down to fair value, with a corresponding charge to earnings. Factors considered in judging whether an impairment is other than temporary include: the financial condition, business prospects and creditworthiness of the issuer; the relative amount of the decline; MidAmerican Energy's ability and intent to hold the investment until the fair value recovers; and the length of time that fair value has been less than cost. Impairment losses on equity securities are charged to earnings. With respect to an investment in a debt security, any resulting impairment loss is recognized in earnings if MidAmerican Energy intends to sell, or expects to be required to sell, the debt security before its amortized cost is recovered. If MidAmerican Energy does not expect to ultimately recover the amortized cost basis even if it does not intend to sell the security, the credit loss component is recognized in earnings and any difference between fair value and the amortized cost basis, net of the credit loss, is reflected in other comprehensive income (loss) ("OCI"). For regulated investments, any impairment charge is offset by the establishment of a regulatory asset to the extent recovery in regulated rates is probable.

Allowance for Doubtful Accounts

Receivables are stated at the outstanding principal amount, net of an estimated allowance for doubtful accounts. The allowance for doubtful accounts is based on MidAmerican Energy's assessment of the collectibility of amounts owed to it by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. As of December 31, 2016 and 2015, the allowance for doubtful accounts totaled $7 million and $6 million, respectively, and is included in receivables, net on the Balance Sheets.

Derivatives

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

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

For MidAmerican Energy's derivatives not designated as hedging contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as regulatory assets and liabilities.

For MidAmerican Energy's derivatives designated as hedging contracts, MidAmerican Energy formally assesses, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. MidAmerican Energy formally documents hedging activity by transaction type and risk management strategy. Changes in the estimated fair value of a derivative contract designated and qualified as a cash flow hedge, to the extent effective, are included on the Statements of Changes in Equity as AOCI, net of tax, until the contract settles and the hedged item is recognized in earnings. All of MidAmerican Energy's derivatives designated as cash flow hedges and the related AOCI were transferred to a subsidiary of BHE on January 1, 2016, as discussed in Note 3.

Inventories

Inventories consist mainly of coal stocks, totaling $137 million and $102 million as of December 31, 2016 and 2015, respectively, materials and supplies, totaling $99 million and $105 million as of December 31, 2016 and 2015, respectively, and natural gas in storage, totaling $24 million and $27 million as of December 31, 2016 and 2015, respectively. The cost of materials and supplies, coal stocks and fuel oil is determined using the average cost method. The cost of stored natural gas is determined using the last-in-first-out method. With respect to stored natural gas, the replacement cost would be $27 million and $8 million higher as of December 31, 2016 and 2015, respectively.

Utility Plant, Net

General

Additions to utility plant are recorded at cost. MidAmerican Energy capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include debt allowance for funds used during construction ("AFUDC") and equity AFUDC. The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed. Additionally, MidAmerican Energy has regulatory arrangements in Iowa in which the carrying cost of certain utility plant has been reduced for amounts associated with electric returns on equity exceeding specified thresholds. Amounts expensed under this arrangement are included as a component of depreciation and amortization.

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

Generally, when MidAmerican Energy retires or sells a component of utility plant, it charges the original cost, net of any proceeds from the disposition to accumulated depreciation. Any gain or loss on disposals of nonregulated assets is recorded through earnings.

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of its regulated facilities, is capitalized by MidAmerican Energy as a component of utility plant, with offsetting credits to the Statements of Operations. AFUDC is computed based on guidelines set forth by the FERC. After construction is completed, MidAmerican Energy is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets.

Asset Retirement Obligations

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

Impairment

MidAmerican Energy evaluates long-lived assets for impairment, including utility plant, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value. The impacts of regulation are considered when evaluating the carrying value of regulated assets. For all other assets, any resulting impairment loss is reflected on the Statements of Operations.

Revenue Recognition

Revenue from electric and natural gas customers is recognized as electricity or natural gas is delivered or services are provided. Revenue recognized includes billed and unbilled amounts. As of December 31, 2016 and 2015, unbilled revenue was $87 million and $138 million, respectively, and is included in receivables, net on the Balance Sheets.

The determination of customer billings is based on a systematic reading of customer meters and applicable rates. At the end of each month, amounts of energy provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns, total volumes supplied to the system, line losses, economic impacts and composition of customer classes. Unbilled revenue is reversed in the following month and billed revenue is recorded based on the subsequent meter readings.

All of MidAmerican Energy's regulated retail electric and gas sales are subject to energy adjustment clauses. MidAmerican Energy also has costs that are recovered, at least in part, through bill riders, including demand-side management and certain transmission costs. The clauses and riders allow MidAmerican Energy to adjust the amounts charged for electric and gas service as the related costs change. The costs recovered in revenue through use of the adjustment clauses and bill riders are charged to expense in the same year the related revenue is recognized. At any given time, these costs may be over or under collected from customers. The total under collection included in receivables at December 31, 2016 and 2015, was $31 million and $17 million, respectively.

MidAmerican Energy collects from its customers sales and excise taxes assessed by governmental authorities on transactions with customers and later remits the collected taxes to the appropriate authority. If the obligation to pay a particular tax resides with the customer, MidAmerican Energy reports such taxes collected on a net basis and, accordingly, they do not affect the Statement of Operations. Taxes for which the obligation resides with MidAmerican Energy are reported on a gross basis in operating revenue and operating expenses. The amounts reported on a gross basis are not material.

Unamortized Debt Premiums, Discounts and Issuance Costs

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

Income Taxes

Berkshire Hathaway includes MidAmerican Funding and MidAmerican Energy in its United States federal income tax return. MidAmerican Funding's and MidAmerican Energy's provisions for income taxes have been computed on a stand-alone basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using estimated income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities that are associated with components of OCI are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities that are associated with income tax benefits and expense for certain property-related basis differences and other various differences that MidAmerican Energy is required to pass on to its customers in Iowa are charged or credited directly to a regulatory asset or liability. As of December 31, 2016 and 2015, these amounts were recognized as a net regulatory asset totaling $985 million and $858 million, respectively, and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Investment tax credits are generally deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory jurisdictions.

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

New Accounting Pronouncements

In November 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-18, which amends FASB Accounting Standards Codification ("ASC") Subtopic 230-10, “Statement of Cash Flows - Overall.” The amendments in this guidance require that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively, wherein the statement of cash flows of each period presented should be adjusted to reflect the new guidance. MidAmerican Energy is currently evaluating the impact of adopting this guidance on its Financial Statements and disclosures included within Notes to Financial Statements.

In August 2016, the FASB issued ASU No. 2016-15, which amends FASB ASC Topic 230, "Statement of Cash Flows." The amendments in this guidance address the classification of eight specific cash flow issues within the statement of cash flows with the objective of reducing the existing diversity in practice. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. MidAmerican Energy is currently evaluating the impact of adopting this guidance on its Financial Statements.

In February 2016, the FASB issued ASU No. 2016-02, which creates FASB ASC Topic 842, "Leases" and supersedes Topic 840 "Leases." This guidance increases transparency and comparability among entities by recording lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. A lessee should recognize in the balance sheet a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from previous guidance. This guidance is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted, and is required to be adopted using a modified retrospective approach. MidAmerican Energy is currently evaluating the impact of adopting this guidance on its Financial Statements and disclosures included within Notes to Financial Statements.

In January 2016, the FASB issued ASU No. 2016-01, which amends FASB ASC Subtopic 825-10, "Financial Instruments - Overall." The amendments in this guidance address certain aspects of recognition, measurement, presentation and disclosure of financial instruments including a requirement that all investments in equity securities that do not qualify for equity method accounting or result in consolidation of the investee be measured at fair value with changes in fair value recognized in net income. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption not permitted, and is required to be adopted prospectively by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. MidAmerican Energy is currently evaluating the impact of adopting this guidance on its Financial Statements and disclosures included within Notes to 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. During 2016, the FASB issued several ASUs that clarify the implementation guidance for ASU No. 2014-09 but do not change the core principle of the guidance. This guidance may be adopted retrospectively or under a modified retrospective method where the cumulative effect is recognized at the date of initial application. MidAmerican Energy is currently evaluating the impact of adopting this guidance on its Financial Statements and disclosures included within Notes to Financial Statements. MidAmerican Energy currently does not expect the timing and amount of revenue currently recognized to be materially different after adoption of the new guidance as a majority of revenue is recognized equal to what MidAmerican Energy has the right to invoice as it corresponds directly with the value to the customer of MidAmerican Energy's performance to date. MidAmerican Energy's current plan is to quantitatively disaggregate revenue in the required financial statement footnote by jurisdiction for each segment.

(3) Discontinued Operations

On January 1, 2016, MidAmerican Energy transferred the assets and liabilities of its unregulated retail services business to a subsidiary of BHE. The transfer was made at MidAmerican Energy's carrying value of the assets, liabilities and AOCI as of December 31, 2015, and was recorded by MidAmerican Energy as a noncash dividend. Financial results of the unregulated retail services business for the years ended December 31, 2015 and 2014, respectively, have been reclassified to discontinued operations in the Statements of Operations.

Significant line items constituting pre-tax income from discontinued operations and total cash flows from operating activities for the years ended December 31 are as follows (in millions):

	2015	2014
Operating revenue	$ 905	$ 918
Cost of sales	$ 854	$ 863
Cash flows from operating activities	$ 30	$ (22)

Assets, liabilities and equity of the unregulated retail services business reflected in the Balance Sheets as of December 31, 2015 are as follows (in millions):

Receivables	$ 115
Derivative assets	41
Deferred income taxes	21
Accounts payable	(49)
Derivative liabilities	(42)
Other assets and liabilities, net	4
Accumulated other comprehensive loss, net	27
Equity, excluding accumulated other comprehensive loss, net	(117)

(4) Property, Plant and Equipment, Net

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

	Depreciable Life	2016	2015
Utility plant in service:			
Generation	20-70 years	$ 11,282	$ 10,404
Transmission	52-75 years	1,726	1,305
Electric distribution	20-75 years	3,197	3,059
Gas distribution	28-70 years	1,565	1,507
Utility plant in service		17,770	16,275
Accumulated depreciation and amortization		(5,448)	(5,229)
Utility plant in service, net		12,322	11,046
Nonregulated property, net:			
Nonregulated property gross	20-50 years	7	15
Accumulated depreciation and amortization		(1)	(5)
Nonregulated property, net		6	10
		12,328	11,056
Construction work-in-progress		493	667
Property, plant and equipment, net		$ 12,821	$ 11,723

Nonregulated property includes land, computer software and other assets not recoverable for regulated utility purposes. Computer software reflected in nonregulated property for 2015 was transferred to a subsidiary of BHE on January 1, 2016.

The average depreciation and amortization rates applied to depreciable utility plant for the years ended December 31 were as follows:

	2016	2015	2014
Electric	2.8%	3.0%	2.8%
Gas	2.9%	2.9%	2.8%

During the fourth quarter of 2016, MidAmerican Energy revised its electric and gas depreciation rates based on the results of a new depreciation study, the most significant impact of which was longer estimated useful lives for certain wind-powered generating facilities. The effect of this change was to reduce depreciation and amortization expense by $3 million in 2016 and $34 million annually based on depreciable plant balances at the time of the change.

(5) Jointly Owned Utility Facilities

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

The amounts shown in the table below represent MidAmerican Energy's share in each jointly owned facility as of December 31, 2016 (dollars in millions):

	Company Share	Plant in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Louisa Unit No. 1	88.0%	$ 766	$ 418	$ 9
Quad Cities Unit Nos. 1 & 2[1]	25.0	689	367	7
Walter Scott, Jr. Unit No. 3	79.1	614	303	1
Walter Scott, Jr. Unit No. 4[2]	59.7	448	101	2
George Neal Unit No. 4	40.6	307	154	1
Ottumwa Unit No. 1	52.0	548	191	13
George Neal Unit No. 3	72.0	426	174	1
Transmission facilities[3]	Various	247	86	1
Total		$ 4,045	$ 1,794	$ 35

(1) Includes amounts related to nuclear fuel.

(2) Plant in service and accumulated depreciation and amortization amounts are net of credits applied under Iowa revenue sharing arrangements totaling $319 million and $75 million, respectively.

(3) Includes 345 and 161 kilovolt transmission lines and substations.

(6) Regulatory Matters

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

	Average Remaining Life	2016	2015
Deferred income taxes, net[1]	29 years	$ 985	$ 858
Asset retirement obligations[2]	9 years	105	94
Employee benefit plans[3]	11 years	40	39
Unrealized loss on regulated derivative contracts	1 year	2	20
Other	Various	29	33
Total		$ 1,161	$ 1,044

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

(2) Amount predominantly relates to asset retirement obligations for fossil-fueled and wind-powered generating facilities. Refer to Note 12 for a discussion of asset retirement obligations.

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

MidAmerican Energy had regulatory assets not earning a return on investment of $1.2 billion and $1.0 billion as of December 31, 2016 and 2015, respectively.

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

	Average Remaining Life	2016	2015
Cost of removal accrual[1]	29 years	$ 665	$ 653
Asset retirement obligations[2]	36 years	117	140
Pre-funded AFUDC on transmission MVPs[3]	56 years	35	19
Iowa electric revenue sharing accrual[4]	1 year	30	—
Employee benefit plans[5]	11 years	12	—
Unrealized gain on regulated derivative contracts	1 year	6	—
Other	Various	18	19
Total		$ 883	$ 831

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

(2) Amount predominantly represents the excess of nuclear decommission trust assets over the related asset retirement obligation. Refer to Note 12 for a discussion of asset retirement obligations.

(3) Represents AFUDC accrued on transmission MVPs that is deducted from rate base as a result of the inclusion of related construction work-in-progress in rate base.

(4) Represents current-year accruals under a regulatory arrangement in Iowa in which equity returns exceeding specified thresholds reduce utility plant upon final determination.

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

(7) Investments and Restricted Cash and Investments

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

	2016	2015
Nuclear decommissioning trust	$ 460	$ 429
Rabbi trusts	184	175
Auction rate securities	—	26
Other	9	4
Total	$ 653	$ 634

MidAmerican Energy has established a trust for the investment of funds for decommissioning the Quad Cities Station. These investments in debt and equity securities are classified as available-for-sale and are reported at fair value. Funds are invested in the trust in accordance with applicable federal and state investment guidelines and are restricted for use as reimbursement for costs of decommissioning the Quad Cities Station, which is currently licensed for operation until December 2032. As of December 31, 2016 and 2015, the fair value of the trust's funds was invested as follows: 54% and 56%, respectively, in domestic common equity securities, 35% and 31%, respectively, in United States government securities, 8% and 9%, respectively, in domestic corporate debt securities and 3% and 4%, respectively, in other securities.

Rabbi trusts primarily hold corporate-owned life insurance on certain current and former key executives and directors. The Rabbi trusts were established to hold investments used to fund the obligations of various nonqualified executive and director compensation plans and to pay the costs of the trusts. The amount represents the cash surrender value of all of the policies included in the Rabbi trusts, net of amounts borrowed against the cash surrender value. Changes in the cash surrender value of the policies are reflected in other income and (expense) - other, net on the Statements of Operation.

MidAmerican Energy had investments in interest bearing auction rate securities with a par value of $35 million as of December 31, 2015. MidAmerican Energy considered the securities to be temporarily impaired, except for an other-than-temporary impairment of $3 million, after-tax, recorded in 2008, and had recorded unrealized losses on the securities of $3 million, after tax, in AOCI as of December 31, 2015. All of the securities were redeemed at par value during 2016, and MidAmerican Energy recorded a $3 million after-tax gain as a result of the previous other-than-temporary impairment.

(8) Short-Term Debt and Credit Facilities

Interim financing of working capital needs and the construction program is obtained from unaffiliated parties through the sale of commercial paper or short-term borrowing from banks. MidAmerican Energy has a $600 million unsecured credit facility expiring in March 2018. The credit facility, which supports MidAmerican Energy's commercial paper program and its variable-rate tax-exempt bond obligations and provides for the issuance of letters of credit, has a variable interest rate based on the London Interbank Offered Rate ("LIBOR") or a base rate, at MidAmerican Energy's option, plus a spread that varies based on MidAmerican Energy's credit ratings for senior unsecured long-term debt securities. In addition, MidAmerican Energy has a $5 million unsecured credit facility, which expires in June 2017 and has a variable interest rate based on LIBOR plus a spread. As of December 31, 2016, the weighted average interest rate on commercial paper borrowings outstanding was 0.73%. The $600 million credit facility requires that MidAmerican Energy's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of any quarter. As of December 31, 2016, MidAmerican Energy was in compliance with the covenants of its credit facilities. MidAmerican Energy has authority from the FERC to issue commercial paper and bank notes aggregating $605 million through February 28, 2017, and $905 million from March 1, 2017, through February 28, 2019.

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

	2016	2015
Credit facilities	$ 605	$ 605
Less:		
Short-term debt outstanding	(99)	—
Variable-rate tax-exempt bond support	(220)	(195)
Net credit facilities	$ 286	$ 410

(9) Long-Term Debt

MidAmerican Energy's long-term debt consists of the following, including amounts maturing within one year and unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2016	2015
First mortgage bonds:			
2.40%, due 2019	$ 500	$ 499	$ 499
3.70%, due 2023	250	248	248
3.50%, due 2024	500	501	502
4.80%, due 2043	350	345	345
4.40%, due 2044	400	394	394
4.25%, due 2046	450	445	444
Notes:			
5.95% Series, due 2017	250	250	250
5.3% Series, due 2018	350	350	349
6.75% Series, due 2031	400	396	395
5.75% Series, due 2035	300	298	298
5.8% Series, due 2036	350	347	347
Transmission upgrade obligation, 4.45% and 3.42% due through 2035 and 2036, respectively	10	7	4
Variable-rate tax-exempt bond obligation series: (weighted average interest rate-2016-0.76%, 2015-0.03%):			
Due 2016	—	—	33
Due 2017	—	—	4
Due 2023, issued in 1993	7	7	7
Due 2023, issued in 2008	57	57	57
Due 2024	35	35	35
Due 2025	13	13	13
Due 2036	33	33	—
Due 2038	45	45	45
Due 2046	30	29	—
Capital lease obligations - 4.16%, due through 2020	2	2	2
Total	$ 4,332	$ 4,301	$ 4,271

The annual repayments of MidAmerican Energy's long-term debt for the years beginning January 1, 2017, and thereafter, excluding unamortized premiums, discounts and debt issuance costs, are as follows (in millions):

2017	$ 251
2018	351
2019	500
2020	2
2021	1
2022 and thereafter	3,227

Pursuant to MidAmerican Energy's mortgage dated September 9, 2013, MidAmerican Energy's first mortgage bonds, currently and from time to time outstanding, are secured by a first mortgage lien on substantially all of its electric generating, transmission and distribution property within the State of Iowa, subject to certain exceptions and permitted encumbrances. As of December 31, 2016, MidAmerican Energy's eligible property subject to the lien of the mortgage totaled approximately $15 billion based on original cost. Additionally, MidAmerican Energy's senior notes outstanding are equally and ratably secured with the first mortgage bonds as required by the indentures under which the senior notes were issued.

MidAmerican Energy's variable-rate tax-exempt obligations, including the tax-exempt bonds discussed above, bear interest at rates that are periodically established through remarketing of the bonds in the short-term tax-exempt market. MidAmerican Energy, at its option, may change the mode of interest calculation for these bonds by selecting from among several floating or fixed rate alternatives. The interest rates shown in the table above are the weighted average interest rates as of December 31, 2016 and 2015. MidAmerican Energy maintains revolving credit facility agreements to provide liquidity for holders of these issues.

In September 2016, the Iowa Finance Authority issued $33 million of variable-rate tax-exempt Pollution Control Facilities Refunding Revenue Bonds due September 2036, the proceeds of which were loaned to MidAmerican Energy to refinance, in September 2016, variable-rate tax-exempt pollution control refunding revenue bonds totaling $29 million due September 2016 and $4 million due March 2017, which were optionally redeemed in full.

In December 2016, the Iowa Finance Authority issued $30 million of its variable-rate, tax-exempt Solid Waste Facilities Revenue Bonds due December 2046, the proceeds of which were loaned to MidAmerican Energy for purpose of constructing solid waste facilities. The bonds are secured by an equal amount of first mortgage bonds pursuant to MidAmerican Energy's mortgage dated September 9, 2013, as supplemented and amended.

As of December 31, 2016, MidAmerican Energy was in compliance with all of its applicable long-term debt covenants.

In March 1999, MidAmerican Energy committed to the IUB to use commercially reasonable efforts to maintain an investment grade rating on its long-term debt and to maintain its common equity level above 42% of total capitalization unless circumstances beyond its control result in the common equity level decreasing to below 39% of total capitalization. MidAmerican Energy must seek the approval from the IUB of a reasonable utility capital structure if MidAmerican Energy's common equity level decreases below 42% of total capitalization, unless the decrease is beyond the control of MidAmerican Energy. MidAmerican Energy is also required to seek the approval of the IUB if MidAmerican Energy's equity level decreases to below 39%, even if the decrease is due to circumstances beyond the control of MidAmerican Energy. As of December 31, 2016, MidAmerican Energy's common equity ratio was 53% computed on a basis consistent with its commitment. As a result of its regulatory commitment to maintain its common equity level above certain thresholds, MidAmerican Energy could dividend $2.0 billion as of December 31, 2016, without falling below 42%.

(10) Income Taxes

MidAmerican Energy's income tax benefit from continuing operations consists of the following for the years ended December 31 (in millions):

	2016	2015	2014
Current:			
Federal	$ (479)	$ (415)	$ (411)
State	(14)	(6)	(4)
	(493)	(421)	(415)
Deferred:			
Federal	366	281	298
State	(4)	(6)	2
	362	275	300
Investment tax credits	(1)	(1)	(1)
Total	$ (132)	$ (147)	$ (116)

A reconciliation of the federal statutory income tax rate to MidAmerican Energy's effective income tax rate applicable to income before income tax benefit from continuing operations is as follows for the years ended December 31:

	2016	2015	2014
Federal statutory income tax rate	35 %	35 %	35 %
Income tax credits	(61)	(71)	(65)
State income tax, net of federal income tax benefit	(3)	(2)	—
Effects of ratemaking	(3)	(12)	(9)
Other, net	—	1	(2)
Effective income tax rate	(32)%	(49)%	(41)%

Income tax credits relate primarily to production tax credits earned by MidAmerican Energy's wind-powered generating facilities. 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.

MidAmerican Energy's net deferred income tax liability consists of the following as of December 31 (in millions):

	2016	2015
Deferred income tax assets:		
Regulatory liabilities	$ 333	$ 327
Asset retirement obligations	230	214
Employee benefits	66	66
Other	74	88
Total deferred income tax assets	703	695
Deferred income tax liabilities:		
Depreciable property	(3,763)	(3,321)
Regulatory assets	(471)	(418)
Other	(41)	(17)
Total deferred income tax liabilities	(4,275)	(3,756)
Net deferred income tax liability	$ (3,572)	$ (3,061)

As of December 31, 2016, MidAmerican Energy has available $25 million of state tax carryforwards, principally related to $549 million of net operating losses, that expire at various intervals between 2017 and 2035.

The United States Internal Revenue Service has closed its examination of BHE's income tax returns through December 31, 2009, including components related to MidAmerican Energy. In addition, state jurisdictions have closed their examinations of MidAmerican Energy's income tax returns for Iowa through December 31, 2012, for Illinois through December 31, 2008, and for other jurisdictions through December 31, 2009.

A reconciliation of the beginning and ending balances of MidAmerican Energy's net unrecognized tax benefits is as follows for the years ended December 31 (in millions):

	2016	2015
Beginning balance	$ 10	$ 26
Additions based on tax positions related to the current year	—	3
Additions for tax positions of prior years	10	47
Reductions based on tax positions related to the current year	(2)	(6)
Reductions for tax positions of prior years	(8)	(46)
Statute of limitations	—	(5)
Settlements	—	(6)
Interest and penalties	—	(3)
Ending balance	$ 10	$ 10

As of December 31, 2016, MidAmerican Energy had unrecognized tax benefits totaling $29 million that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect MidAmerican Energy's effective income tax rate.

(11) Employee Benefit Plans

MidAmerican Energy sponsors a noncontributory defined benefit pension plan covering a majority of all employees of BHE and its domestic energy subsidiaries other than PacifiCorp and NV Energy, Inc. Benefit obligations under the plan are based on a cash balance arrangement for salaried employees and most union employees and final average pay formulas for other union employees. MidAmerican Energy also maintains noncontributory, nonqualified defined benefit supplemental executive retirement plans ("SERP") for certain active and retired participants.

MidAmerican Energy also sponsors certain postretirement healthcare and life insurance benefits covering substantially all retired employees of BHE and its domestic energy subsidiaries other than PacifiCorp and NV Energy, Inc. Under the plans, a majority of all employees of the participating companies may become eligible for these benefits if they reach retirement age. New employees are not eligible for benefits under the plans. MidAmerican Energy has been allowed to recover accrued pension and other postretirement benefit costs in its electric and gas service rates.

Net Periodic Benefit Cost

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

MidAmerican Energy bills to and is reimbursed currently for affiliates' share of the net periodic benefit costs from all plans in which such affiliates participate. In 2016, 2015 and 2014, MidAmerican Energy's share of the pension net periodic benefit cost (credit) was $(2) million, $(4) million and $1 million, respectively. MidAmerican Energy's share of the other postretirement net periodic benefit cost (credit) in 2016, 2015 and 2014 totaled $(1) million, $- million and $- million, respectively.

Net periodic benefit cost for the plans of MidAmerican Energy and the aforementioned affiliates included the following components for the years ended December 31 (in millions):

	Pension			Other Postretirement		
	2016	2015	2014	2016	2015	2014
Service cost	$ 10	$ 12	$ 14	$ 5	$ 7	$ 6
Interest cost	34	32	35	10	9	10
Expected return on plan assets	(44)	(46)	(45)	(13)	(15)	(15)
Net amortization	2	2	1	(4)	(3)	(3)
Net periodic benefit cost (credit)	$ 2	$ —	$ 5	$ (2)	$ (2)	$ (2)

Funded Status

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

	Pension		Other Postretirement	
	2016	2015	2016	2015
Plan assets at fair value, beginning of year	$ 678	$ 730	$ 249	$ 259
Employer contributions	7	7	1	1
Participant contributions	—	—	1	1
Actual return on plan assets	57	4	14	—
Benefits paid	(58)	(63)	(13)	(12)
Plan assets at fair value, end of year	$ 684	$ 678	$ 252	$ 249

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

	Pension		Other Postretirement	
	2016	2015	2016	2015
Benefit obligation, beginning of year	$ 785	$ 840	$ 234	$ 249
Service cost	10	12	5	7
Interest cost	34	32	10	9
Participant contributions	—	—	1	1
Actuarial loss (gain)	2	(36)	(4)	(20)
Benefits paid	(58)	(63)	(13)	(12)
Benefit obligation, end of year	$ 773	$ 785	$ 233	$ 234
Accumulated benefit obligation, end of year	$ 764	$ 773		

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

	Pension		Other Postretirement	
	2016	2015	2016	2015
Plan assets at fair value, end of year	$ 684	$ 678	$ 252	$ 249
Less - Benefit obligation, end of year	773	785	233	234
Funded status	$ (89)	$ (107)	$ 19	$ 15
Amounts recognized on the Balance Sheets:				
Other assets	$ 26	$ 7	$ 19	$ 15
Other current liabilities	(8)	(8)	—	—
Other liabilities	(107)	(106)	—	—
Amounts recognized	$ (89)	$ (107)	$ 19	$ 15

The SERP has no plan assets; however, MidAmerican Energy and BHE have Rabbi trusts that hold corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERP. The cash surrender value of all of the policies included in the Rabbi trusts, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was $166 million and $156 million as of December 31, 2016 and 2015, respectively, of which $110 million and $104 million was held by MidAmerican Energy as of December 31, 2016 and 2015, respectively, with the remainder held by BHE. These assets are not included in the plan assets in the above table, but are reflected in investments and nonregulated property, net on the Balance Sheets.

Unrecognized Amounts

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

	Pension		Other Postretirement	
	2016	2015	2016	2015
Net loss	$ 15	$ 26	$ 36	$ 42
Prior service cost (credit)	1	2	(31)	(36)
Total	$ 16	$ 28	$ 5	$ 6

MidAmerican Energy sponsors pension and other postretirement benefit plans on behalf of certain of its affiliates in addition to itself, and therefore, the portion of the funded status of the respective plans that has not yet been recognized in net periodic benefit cost is attributable to multiple entities. Additionally, substantially all of MidAmerican Energy's portion of such amounts is either refundable to or recoverable from its customers and is reflected as regulatory liabilities and regulatory assets.

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2016 and 2015 is as follows (in millions):

	Regulatory Asset	Regulatory Liability	Receivables (Payables) with Affiliates	Total
Pension				
Balance, December 31, 2014	$ 22	$ (5)	$ 7	$ 24
Net loss (gain) arising during the year	2	5	(1)	6
Net amortization	(2)	—	—	(2)
Total	—	5	(1)	4
Balance, December 31, 2015	22	—	6	28
Net gain arising during the year	1	(11)	—	(10)
Net amortization	(1)	(1)	—	(2)
Total	—	(12)	—	(12)
Balance, December 31, 2016	$ 22	$ (12)	$ 6	$ 16

	Regulatory Asset	Regulatory Liability	Receivables (Payables) with Affiliates	Total
Other Postretirement				
Balance, December 31, 2014	$ 20	$ —	$ (13)	$ 7
Net gain arising during the year	(5)	—	—	(5)
Net amortization	2	—	2	4
Total	(3)	—	2	(1)
Balance, December 31, 2015	17	—	(11)	6
Net gain arising during the year	(2)	—	(3)	(5)
Net amortization	3	—	1	4
Total	1	—	(2)	(1)
Balance, December 31, 2016	$ 18	$ —	$ (13)	$ 5

The net loss and prior service cost (credit) that will be amortized in 2017 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Cost (Credit)	Total
Pension	$ 1	$ 1	$ 2
Other postretirement	2	(6)	(4)
Total	$ 3	$ (5)	$ (2)

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2016	2015	2014	2016	2015	2014
Benefit obligations as of December 31:						
Discount rate	4.10%	4.50%	4.00%	3.90%	4.25%	3.75%
Rate of compensation increase	2.75%	2.75%	2.75%	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	4.50%	4.00%	4.75%	4.25%	3.75%	4.50%
Expected return on plan assets(1)	7.00%	7.25%	7.50%	6.75%	7.00%	7.25%
Rate of compensation increase	2.75%	2.75%	3.00%	N/A	N/A	N/A

(1) Amounts reflected are pre-tax values. Assumed after-tax returns for a taxable, non-union other postretirement plan were 5.00% for 2016, and 5.18% for 2015, and 5.37% for 2014.

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

	2016	2015
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	7.40%	7.70%
Rate that the cost trend rate gradually declines to	5.00%	5.00%
Year that the rate reaches the rate it is assumed to remain at	2025	2025

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

	One Percentage-Point	
	Increase	Decrease
Increase (decrease) in:		
Total service and interest cost for the year ended December 31, 2016	$ —	$ —
Other postretirement benefit obligation as of December 31, 2016	3	(2)

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $8 million and $1 million, respectively, during 2017. Funding to MidAmerican Energy's pension benefit plan trust is based upon the actuarially determined costs of the plan and the requirements of the Internal Revenue Code, the Employee Retirement Income Security Act of 1974 and the Pension Protection Act of 2006, as amended. MidAmerican Energy considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the Pension Protection Act of 2006, as amended. MidAmerican Energy's funding policy for its other postretirement benefit plan is to generally contribute amounts consistent with its rate regulatory arrangements.

Net periodic benefit costs assigned to MidAmerican Energy affiliates are reimbursed currently in accordance with its intercompany administrative services agreement. The expected benefit payments to participants in MidAmerican Energy's pension and other postretirement benefit plans for 2017 through 2021 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2017	$ 60	$ 18
2018	60	19
2019	62	20
2020	62	21
2021	60	21
2022-2026	278	97

Plan Assets

Investment Policy and Asset Allocations

MidAmerican Energy's investment policy for its pension and other postretirement benefit plans is to balance risk and return through a diversified portfolio of debt securities, equity securities and other alternative investments. Maturities for debt securities are managed to targets consistent with prudent risk tolerances. The plans retain outside investment advisors to manage plan investments within the parameters outlined by the MidAmerican Energy Pension and Employee Benefits Plans Administrative Committee. The investment portfolio is managed in line with the investment policy with sufficient liquidity to meet near-term benefit payments.

The target allocations (percentage of plan assets) for MidAmerican Energy's pension and other postretirement benefit plan assets are as follows as of December 31, 2016:

	Pension	Other Postretirement
	%	%
Debt securities(1)	20-40	25-45
Equity securities(1)	60-80	50-80
Real estate funds	2-8	—
Other	0-5	0-5

(1) For purposes of target allocation percentages and consistent with the plans' investment policy, investment funds are allocated based on the underlying investments in debt and equity securities.

Fair Value Measurements

MidAmerican Energy adopted ASU No. 2015-07, "Fair Value Measurement (Topic 820) - Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share (or its Equivalent)" effective January 1, 2016 under a retrospective method.

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

	Input Levels for Fair Value Measurements[1]			
	Level 1	**Level 2**	**Level 3**	**Total**
As of December 31, 2016:				
Cash equivalents	$ —	$ 17	$ —	$ 17
Debt securities:				
United States government obligations	9	—	—	9
Corporate obligations	—	53	—	53
Municipal obligations	—	6	—	6
Agency, asset and mortgage-backed obligations	—	22	—	22
Equity securities:				
United States companies	130	—	—	130
International equity securities	39	—	—	39
Investment funds[2]	63	—	—	63
Total assets in the hierarchy	$ 241	$ 98	$ —	339
Investment funds[2] measured at net asset value				295
Real estate funds measured at net asset value				50
Total assets measured at fair value				$ 684
As of December 31, 2015:				
Cash equivalents	$ —	$ 16	$ —	$ 16
Debt securities:				
United States government obligations	5	—	—	5
Corporate obligations	—	57	—	57
Municipal obligations	—	6	—	6
Agency, asset and mortgage-backed obligations	—	27	—	27
Equity securities:				
United States companies	130	—	—	130
International equity securities	40	—	—	40
Investment funds[2]	61	—	—	61
Total assets in the hierarchy	$ 236	$ 106	$ —	342
Investment funds[2] measured at net asset value				296
Real estate funds measured at net asset value				40
Total assets measured at fair value				$ 678

(1) Refer to Note 14 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 74% and 26%, respectively, for 2016 and 72% and 28%, respectively, for 2015. Additionally, these funds are invested in United States and international securities of approximately 71% and 29%, respectively, for 2016 and 73% and 27%, respectively, for 2015.

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

	Input Levels for Fair Value Measurements[1] Level 1	Level 2	Level 3	Total
As of December 31, 2016:				
Cash equivalents	$ 10	$ —	$ —	$ 10
Debt securities:				
United States government obligations	5	—	—	5
Corporate obligations	—	11	—	11
Municipal obligations	—	37	—	37
Agency, asset and mortgage-backed obligations	—	11	—	11
Equity securities:				
United States companies	122	—	—	122
Investment funds[2]	56	—	—	56
Total assets measured at fair value	$ 193	$ 59	$ —	$ 252
As of December 31, 2015:				
Cash equivalents	$ 5	$ —	$ —	$ 5
Debt securities:				
United States government obligations	5	—	—	5
Corporate obligations	—	12	—	12
Municipal obligations	—	39	—	39
Agency, asset and mortgage-backed obligations	—	12	—	12
Equity securities:				
United States companies	120	—	—	120
Investment funds[2]	56	—	—	56
Total assets measured at fair value	$ 186	$ 63	$ —	$ 249

(1) Refer to Note 14 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 70% and 30%, respectively, for 2016 and 68% and 32%, respectively, for 2015. Additionally, these funds are invested in United States and international securities of approximately 30% and 70%, respectively, for 2016 and 32% and 68%, respectively, for 2015.

For level 1 investments, 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. For level 2 investments, the fair value is determined using pricing models based on observable market inputs. Shares of mutual funds not registered under the Securities Act of 1933, private equity limited partnership interests, common and commingled trust funds and investment entities are reported at fair value based on the net asset value per unit, which is used for expedience purposes. A fund's net asset value is based on the fair value of the underlying assets held by the fund less its liabilities.

MidAmerican Energy sponsors a defined contribution plan ("401(k) plan") covering substantially all employees. MidAmerican Energy's matching contributions are based on each participant's level of contribution, and certain participants receive contributions based on eligible pre-tax annual compensation. Contributions cannot exceed the maximum allowable for tax purposes. Certain participants now receive enhanced benefits in the 401(k) plan and no longer accrue benefits in the noncontributory defined benefit pension plans. MidAmerican Energy's contributions to the plan were $20 million, $20 million, and $19 million for the years ended December 31, 2016, 2015 and 2014, respectively.

(12) Asset Retirement Obligations

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

MidAmerican Energy does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain generation, transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled $665 million and $653 million as of December 31, 2016 and 2015, respectively.

The following table presents MidAmerican Energy's ARO liabilities by asset type as of December 31, (in millions):

	2016	2015
Quad Cities Station	$ 343	$ 289
Fossil-fueled generating facilities	132	160
Wind-powered generating facilities	91	82
Other	1	1
Total asset retirement obligations	$ 567	$ 532
Quad Cities Station nuclear decommissioning trust funds[1]	$ 460	$ 429

(1) Refer to Note 7 for a discussion of the Quad Cities Station nuclear decommissioning trust funds.

The following table reconciles the beginning and ending balances of MidAmerican Energy's ARO liabilities for the years ended December 31, (in millions):

	2016	2015
Beginning balance	$ 532	$ 460
Change in estimated costs	28	36
Additions	14	22
Retirements	(32)	(9)
Accretion	25	23
Ending balance	$ 567	$ 532
Reflected as:		
Other current liabilities	$ 57	$ 44
Asset retirement obligations	510	488
	$ 567	$ 532

The change in estimated costs for 2016 was primarily the result of a new decommissioning study conducted by the operator of Quad Cities Station that changed the estimated amount and timing of cash flows. The change in estimated costs for 2015 was primarily due to changes in the expected timing and amount of cash flows related to the implementation of the United States Environmental Protection Agency's 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, which was effective in October 2015.

(13) Risk Management and Hedging Activities

MidAmerican Energy is exposed to the impact of market fluctuations in commodity prices and interest rates. MidAmerican Energy is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk as it has an obligation to serve retail customer load in its regulated service territory. Prior to January 1, 2016, MidAmerican Energy also provided nonregulated retail electricity and natural gas services in competitive markets, which created contractual obligations to provide electric and natural gas services. MidAmerican Energy's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity, wholesale electricity that is purchased and sold, and natural gas supply for retail customers. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather; market liquidity; generating facility availability; customer usage; storage; and transmission and transportation constraints. Interest rate risk exists on variable-rate debt and future debt issuances. MidAmerican Energy does not engage in a material amount of proprietary trading activities.

MidAmerican Energy 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, MidAmerican Energy 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. MidAmerican Energy 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, MidAmerican Energy may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate its exposure to interest rate risk. MidAmerican Energy does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in MidAmerican Energy's accounting policies related to derivatives. Refer to Notes 2 and 14 for additional information on derivative contracts and to Note 3 for a discussion of discontinued operations.

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 MidAmerican Energy's derivative contracts, on a gross basis, and reconciles those amounts to the amounts presented on a net basis on the Balance Sheets (in millions):

	Other Current Assets	Other Assets	Other Current Liabilities	Other Long-term Liabilities	Total
As of December 31, 2016:					
Not designated as hedging contracts[(1)(2)]:					
Commodity assets	$ 8	$ 2	$ —	$ —	$ 10
Commodity liabilities	(2)	—	(3)	(1)	(6)
Total	6	2	(3)	(1)	4
Designated as hedging contracts[(2)]:					
Commodity assets	—	—	—	—	—
Commodity liabilities	—	—	—	—	—
Total	—	—	—	—	—
Total derivatives	6	2	(3)	(1)	4
Cash collateral receivable	—	—	1	—	1
Total derivatives - net basis	$ 6	$ 2	$ (2)	$ (1)	$ 5
As of December 31, 2015:					
Not designated as hedging contracts[(1)]:					
Commodity assets	$ 12	$ 4	$ 5	$ 2	$ 23
Commodity liabilities	(3)	—	(36)	(10)	(49)
Total	9	4	(31)	(8)	(26)
Designated as hedging contracts:					
Commodity assets	—	—	1	2	3
Commodity liabilities	—	—	(32)	(17)	(49)
Total	—	—	(31)	(15)	(46)
Total derivatives	9	4	(62)	(23)	(72)
Cash collateral receivable	—	—	22	6	28
Total derivatives - net basis	$ 9	$ 4	$ (40)	$ (17)	$ (44)

(1) MidAmerican Energy's commodity derivatives not designated as hedging contracts are generally included in regulated rates. Accordingly, as of December 31, 2016, a net regulatory liability of $4 million was recorded related to the net derivative asset of $4 million, and as of December 31, 2015, a net regulatory asset of $20 million was recorded related to the net derivative liability of $26 million.

(2) The changes in derivative values from December 31, 2015, are substantially due to the transfer of MidAmerican Energy's unregulated retail services business to a subsidiary of BHE.

Not Designated as Hedging Contracts

The following table reconciles the beginning and ending balances of MidAmerican Energy's net regulatory assets (liabilities) and summarizes the pre-tax gains and losses on commodity derivative contracts recognized in net regulatory assets (liabilities), as well as amounts reclassified to earnings for the years ended December 31 (in millions):

	2016	2015	2014
Beginning balance	$ 20	$ 38	$ 10
Changes in fair value recognized in net regulatory assets (liabilities)	3	40	61
Net losses reclassified to operating revenue	(15)	(42)	(28)
Net losses reclassified to cost of fuel, energy and capacity	—	(1)	(1)
Net losses reclassified to cost of gas sold	(12)	(15)	(4)
Ending balance	$ (4)	$ 20	$ 38

The following table summarizes the pre-tax unrealized gains (losses) included on the Statements of Operations associated with MidAmerican Energy's derivative contracts not designated as hedging contracts and not recorded as a net regulatory asset or liability for the years ended December 31 (in millions):

	2016	2015	2014
Nonregulated operating revenue	$ —	$ 15	$ 6
Regulated cost of fuel, energy and capacity	—	2	—
Nonregulated cost of sales	—	(21)	9
Total	$ —	$ (4)	$ 15

Designated as Hedging Contracts

MidAmerican Energy used derivative contracts accounted for as cash flow hedges to hedge electricity and natural gas commodity prices related to its unregulated retail services business, which was transferred to a subsidiary of BHE. The following table reconciles the beginning and ending balances of MidAmerican Energy's accumulated other comprehensive loss (pre-tax) and summarizes pre-tax gains and losses on derivative contracts designated and qualifying as cash flow hedges recognized in OCI, as well as amounts reclassified to earnings, for the years ended December 31 (in millions):

	2016	2015	2014
Beginning balance	$ 45	$ 34	$ 11
Transfer to affiliate	(45)	—	—
Changes in fair value recognized in OCI	—	58	(3)
Net (losses) gains reclassified to nonregulated cost of sales	—	(47)	26
Ending balance	$ —	$ 45	$ 34

Derivative Contract Volumes

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

	Unit of Measure	**2016**	**2015**
Electricity purchases	Megawatt hours	—	15
Natural gas purchases	Decatherms	18	17

Credit Risk

MidAmerican Energy is 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. Additionally, MidAmerican Energy participates in the regional transmission organization ("RTO") markets and has indirect credit exposure related to other participants, although RTO credit policies are designed to limit exposure to credit losses from individual participants. Credit risk may be concentrated to the extent MidAmerican Energy's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, MidAmerican Energy analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty, and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, MidAmerican Energy enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtains third-party guarantees, letters of credit and cash deposits. If required, MidAmerican Energy exercises 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 MidAmerican Energy's collateral requirements on its 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 MidAmerican Energy's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2016, MidAmerican Energy's credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of MidAmerican Energy's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $3 million and $66 million as of December 31, 2016 and 2015, respectively, for which MidAmerican Energy had posted collateral of $- million at each date. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of December 31, 2016 and 2015, MidAmerican Energy would have been required to post $2 million and $55 million, respectively, of additional collateral. MidAmerican Energy's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors. MidAmerican Energy's exposure to contingent features declined significantly as a result of the transfer of its unregulated retail services business to a subsidiary of BHE.

(14) Fair Value Measurements

The carrying value of MidAmerican Energy'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. MidAmerican Energy has various financial assets and liabilities that are measured at fair value on the 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 MidAmerican Energy 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 MidAmerican Energy's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. MidAmerican Energy develops these inputs based on the best information available, including its own data.

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

	Input Levels for Fair Value Measurements				
	Level 1	Level 2	Level 3	Other[(1)]	Total
As of December 31, 2016:					
Assets:					
Commodity derivatives	$ —	$ 9	$ 1	$ (2)	$ 8
Money market mutual funds[(2)]	1	—	—	—	1
Debt securities:					
United States government obligations	161	—	—	—	161
International government obligations	—	3	—	—	3
Corporate obligations	—	36	—	—	36
Municipal obligations	—	2	—	—	2
Agency, asset and mortgage-backed obligations	—	2	—	—	2
Equity securities:					
United States companies	250	—	—	—	250
International companies	5	—	—	—	5
Investment funds	9	—	—	—	9
	$ 426	$ 52	$ 1	$ (2)	$ 477
Liabilities - commodity derivatives	$ —	$ (3)	$ (3)	$ 3	$ (3)
As of December 31, 2015					
Assets:					
Commodity derivatives	$ —	$ 8	$ 18	$ (13)	$ 13
Money market mutual funds[(2)]	56	—	—	—	56
Debt securities:					
United States government obligations	133	—	—	—	133
International government obligations	—	2	—	—	2
Corporate obligations	—	39	—	—	39
Municipal obligations	—	1	—	—	1
Agency, asset and mortgage-backed obligations	—	3	—	—	3
Auction rate securities	—	—	26	—	26
Equity securities:					
United States companies	239	—	—	—	239
International companies	6	—	—	—	6
Investment funds	4	—	—	—	4
	$ 438	$ 53	$ 44	$ (13)	$ 522
Liabilities - commodity derivatives	$ (13)	$ (61)	$ (24)	$ 41	$ (57)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $1 million and $28 million as of December 31, 2016 and 2015, respectively.

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

Derivative contracts are recorded on the 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 MidAmerican Energy transacts. When quoted prices for identical contracts are not available, MidAmerican Energy uses forward price curves. Forward price curves represent MidAmerican Energy's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. MidAmerican Energy bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent energy brokers, exchanges, direct communication with market participants and actual transactions executed by MidAmerican Energy. Market price quotations are generally readily obtainable for the applicable term of MidAmerican Energy's outstanding derivative contracts; therefore, MidAmerican Energy'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, MidAmerican Energy 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, related volatility, counterparty creditworthiness and duration of contracts. Refer to Note 13 for further discussion regarding MidAmerican Energy's risk management and hedging activities.

MidAmerican Energy'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 MidAmerican Energy'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 MidAmerican Energy's judgment about the assumptions, including liquidity and nonperformance risks, which market participants would use when pricing the asset. The auction rate securities were fully redeemed at par value in 2016.

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

	Commodity Derivatives			Auction Rate Securities		
	2016	2015	2014	2016	2015	2014
Beginning balance	$ (6)	$ 12	$ (3)	$ 26	$ 26	$ 23
Transfer to affiliate	(4)	—	—	—	—	—
Changes included in earnings(1)	—	11	12	5	—	—
Changes in fair value recognized in OCI	—	(7)	—	4	—	3
Changes in fair value recognized in net regulatory assets	(6)	(25)	6	—	—	—
Purchases	—	1	1	—	—	—
Redemptions	—	—	—	(35)	—	—
Settlements	14	2	(4)	—	—	—
Ending balance	$ (2)	$ (6)	$ 12	$ —	$ 26	$ 26

(1) Changes included in earnings related to MidAmerican Energy's unregulated retail services business that was transferred to an affiliate of BHE. Refer to Note 3 for a discussion of discontinued operations. Net unrealized (losses) gains included in earnings for the years ended December 31, 2015 and 2014, related to commodity derivatives held at December 31, 2015 and 2014, totaled $8 million and $16 million, respectively.

MidAmerican Energy's long-term debt is carried at cost on the Financial Statements. The fair value of MidAmerican Energy'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 MidAmerican Energy'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 MidAmerican Energy's long-term debt as of December 31, (in millions):

	2016		2015	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 4,301	$ 4,735	$ 4,271	$ 4,636

(15) Commitments and Contingencies

Commitments

MidAmerican Energy had the following firm commitments that are not reflected on the Balance Sheet. Minimum payments as of December 31, 2016, are as follows (in millions):

	2017	2018	2019	2020	2021	2022 and Thereafter	Total
Contract type:							
Coal and natural gas for generation	$ 141	$ 73	$ 40	$ —	$ —	$ —	$ 254
Electric capacity and transmission	37	29	29	28	25	59	207
Natural gas contracts for gas operations	137	34	13	12	10	23	229
Construction commitments	347	2	5	—	—	—	354
Easements and operating leases	20	20	20	19	19	624	722
Maintenance and services contracts	72	90	91	92	86	210	641
	$ 754	$ 248	$ 198	$ 151	$ 140	$ 916	$ 2,407

Coal, Natural Gas, Electric Capacity and Transmission Commitments

MidAmerican Energy has coal supply and related transportation and lime contracts for its coal-fueled generating facilities. MidAmerican Energy expects to supplement the coal contracts with additional contracts and spot market purchases to fulfill its future coal supply needs. Additionally, MidAmerican Energy has a natural gas transportation contract for a natural gas-fueled generating facility. The contracts have minimum payment commitments ranging through 2019.

MidAmerican Energy has various natural gas supply and transportation contracts for its regulated and nonregulated gas operations that have minimum payment commitments ranging through 2025.

MidAmerican Energy has contracts to purchase electric capacity to meet its electric system energy requirements that have minimum payment commitments ranging through 2028. MidAmerican Energy also has contracts for the right to transmit electricity over other entities' transmission lines with minimum payment commitments ranging through 2022.

Construction Commitments

MidAmerican Energy's firm construction commitments reflected in the table above consist primarily of contracts for the construction of wind-powered generating facilities in 2017, the settlement of asset retirement obligations for ash pond closures and the construction in 2017 of two Multi-Value Projects approved by the Midcontinent Independent System Operator, Inc. for high voltage transmission lines in Iowa and Illinois.

Easements and Operating Leases

MidAmerican Energy has non-cancelable easements with minimum payment commitments ranging through 2061 for land in Iowa on which its wind-powered generating facilities are located. MidAmerican Energy also has non-cancelable operating leases with minimum payment commitments ranging through 2020 primarily for office and other building space, rail cars and computer equipment. These leases generally require MidAmerican Energy to pay for insurance, taxes and maintenance applicable to the leased property. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. Rent expense on non-cancelable operating leases totaled $4 million, $4 million and $4 million for 2016, 2015 and 2014, respectively.

Maintenance and Services Contracts

MidAmerican Energy has non-cancelable maintenance and services contracts related to various generating facilities with minimum payment commitments ranging through 2027.

Environmental Laws and Regulations

MidAmerican Energy is subject to federal, state and local laws and regulations regarding air and water quality, 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 its current and future operations. MidAmerican Energy believes it is in material compliance with all applicable laws and regulations.

Transmission Rates

MidAmerican Energy's wholesale transmission rates are set annually using FERC-approved formula rates subject to true-up for actual cost of service. Prior to September 2016, the rates in effect were based on a 12.38% return on equity ("ROE"). In November 2013 and February 2015, a coalition of intervenors filed successive complaints with the FERC requesting that the 12.38% ROE no longer be found just and reasonable and sought to reduce the base ROE to 9.15% and 8.67%, respectively. MidAmerican Energy is authorized by the FERC to include a 0.50% adder beyond the base ROE effective January 2015. In September 2016, the FERC issued an order for the first complaint, which reduces the base ROE to 10.32% and requires refunds, plus interest, for the period from November 2013 through February 2015. The FERC is expected to rule on the second complaint by the second quarter of 2017, covering the period from February 2015 through May 2016. MidAmerican Energy believes it is probable that the FERC will order a base ROE lower than 12.38% in the second complaint and, as of December 31, 2016, has accrued a $10 million liability for refunds under both complaints of amounts collected under the higher ROE from November 2013 through May 2016.

Legal Matters

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

(16) Components of Accumulated Other Comprehensive Loss, Net

The following table shows the change in accumulated other comprehensive loss by each component of other comprehensive income, net of applicable income taxes, for the years ended December 31, 2016 and 2015 (in millions):

	Unrealized Losses on Available-For-Sale Securities	Unrealized Losses on Cash Flow Hedges	Accumulated Other Comprehensive Loss, Net
Balance, December 31, 2014	$ (3)	$ (20)	$ (23)
Other comprehensive loss	—	(7)	(7)
Balance, December 31, 2015	$ (3)	$ (27)	$ (30)
Other comprehensive income	3	—	3
Dividend (Note 3)	—	27	27
Balance, December 31, 2016	$ —	$ —	$ —

For information regarding cash flow hedge reclassifications from AOCI to net income in their entirety for the years ended December 31, 2016, 2015 and 2014, refer to Note 13.

(17) Other Income and (Expense) - Other, Net

Other, net, as shown on the Statements of Operations, includes the following other income (expense) items for the years ended December 31 (in millions):

	2016	2015	2014
Corporate-owned life insurance income	$ 8	$ 4	$ 8
Gain on redemption of auction rate securities	5	—	—
Other, net	1	1	2
Total	$ 14	$ 5	$ 10

(18) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ending December 31 is as follows (in millions):

	2016	2015	2014
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 181	$ 154	$ 144
Income taxes received, net	$ 601	$ 629	$ 149
Supplemental disclosure of non-cash investing transactions:			
Accounts payable related to utility plant additions	$ 131	$ 249	$ 128
Dividend of unregulated retail services business (Note 3)	$ 90	$ —	$ —

(19) Related Party Transactions

The companies identified as affiliates of MidAmerican Energy are Berkshire Hathaway and its subsidiaries, including BHE and its subsidiaries. The basis for the following transactions is provided for in service agreements between MidAmerican Energy and the affiliates.

MidAmerican Energy is reimbursed for charges incurred on behalf of its affiliates. The majority of these reimbursed expenses are for general costs, such as insurance and building rent, and for employee wages, benefits and costs related to corporate functions such as information technology, human resources, treasury, legal and accounting. The amount of such reimbursements was $41 million, $46 million and $58 million for 2016, 2015 and 2014, respectively.

MidAmerican Energy reimbursed BHE in the amount of $6 million, $7 million and $8 million in 2016, 2015 and 2014, respectively, for its share of corporate expenses.

MidAmerican Energy purchases natural gas transportation and storage capacity services from Northern Natural Gas Company, a wholly owned subsidiary of BHE, and coal transportation services from BNSF Railway Company, a wholly-owned subsidiary of Berkshire Hathaway, in the normal course of business at either tariffed or market prices. These purchases totaled $135 million, $165 million and $144 million in 2016, 2015 and 2014, respectively.

MidAmerican Energy had accounts receivable from affiliates of $5 million as of December 31, 2016 and 2015, that are included in receivables on the Balance Sheets. MidAmerican Energy also had accounts payable to affiliates of $13 million as of December 31, 2016 and 2015, that are included in accounts payable on the Balance Sheets.

MidAmerican Energy is party to a tax-sharing agreement and is part of the Berkshire Hathaway United States federal income tax return. For current federal and state income taxes, MidAmerican Energy had a payable to BHE of $6 million as of December 31, 2016, and a receivable from BHE of $102 million as of December 31, 2015. MidAmerican Energy received net cash receipts for federal and state income taxes from BHE totaling $601 million, $629 million and $149 million for the years ended December 31, 2016, 2015 and 2014, respectively.

MidAmerican Energy recognizes the full amount of the funded status for its pension and postretirement plans, and amounts attributable to MidAmerican Energy's affiliates that have not previously been recognized through income are recognized as an intercompany balance with such affiliates. MidAmerican Energy adjusts these balances when changes to the funded status of the respective plans are recognized and does not intend to settle the balances currently. Amounts receivable from affiliates attributable to the funded status of employee benefit plans totaled $12 million and $10 million as of December 31, 2016 and 2015, respectively, and similar amounts payable to affiliates totaled $36 million and $29 million as of December 31, 2016 and 2015, respectively. See Note 11 for further information pertaining to pension and postretirement accounting.

(20) Segment Information

MidAmerican Energy has identified two reportable operating segments: regulated electric and regulated gas. The previously reported nonregulated energy segment consisted substantially of MidAmerican Energy's unregulated retail services business, which was transferred to a subsidiary of BHE and is excluded from the information below related to the statements of operations for all periods presented. The regulated electric segment derives most of its revenue from regulated retail sales of electricity to residential, commercial, and industrial customers and from wholesale sales. The regulated gas segment derives most of its revenue from regulated retail sales of natural gas to residential, commercial, and industrial customers and also obtains revenue by transporting gas owned by others through its distribution system. Pricing for regulated electric and regulated gas sales are established separately by regulatory agencies; therefore, management also reviews each segment separately to make decisions regarding allocation of resources and in evaluating performance. Common operating costs, interest income, interest expense and income tax expense are allocated to each segment based on certain factors, which primarily relate to the nature of the cost. Refer to Note 10 for a discussion of items affecting income tax (benefit) expense for the regulated electric and gas operating segments.

The following tables provide information on a reportable segment basis (in millions):

	Years Ended December 31,		
	2016	2015	2014
Operating revenue:			
Regulated electric	$ 1,985	$ 1,837	$ 1,817
Regulated gas	637	661	996
Other	3	4	9
Total operating revenue	$ 2,625	$ 2,502	$ 2,822
Depreciation and amortization:			
Regulated electric	$ 436	$ 366	$ 312
Regulated gas	43	41	39
Total depreciation and amortization	$ 479	$ 407	$ 351
Operating income:			
Regulated electric	$ 497	$ 385	$ 319
Regulated gas	68	64	75
Total operating income	$ 565	$ 449	$ 394
Interest expense:			
Regulated electric	$ 178	$ 166	$ 157
Regulated gas	18	17	17
Total interest expense	$ 196	$ 183	$ 174
Income tax (benefit) expense from continuing operations:			
Regulated electric	$ (156)	$ (163)	$ (138)
Regulated gas	22	16	22
Other	2	—	—
Total income tax (benefit) expense from continuing operations	$ (132)	$ (147)	$ (116)
Net income:			
Regulated electric	$ 512	$ 413	$ 361
Regulated gas	32	33	40
Other	(2)	—	—
Income from continuing operations	542	446	401
Income on discontinued operations	—	16	16
Net income	$ 542	$ 462	$ 417

	Years Ended December 31,		
	2016	2015	2014
Utility construction expenditures:			
Regulated electric	$ 1,564	$ 1,365	$ 1,429
Regulated gas	72	81	97
Total utility construction expenditures	$ 1,636	$ 1,446	$ 1,526

	As of December 31,		
	2016	2015	2014
Total assets:			
Regulated electric	$ 14,113	$ 12,970	$ 11,850
Regulated gas	1,345	1,251	1,217
Other	1	164	167
Total assets	$ 15,459	$ 14,385	$ 13,234

(21) Subsequent Events

In February 2017, MidAmerican Energy issued $375 million of its 3.10% First Mortgage Bonds due May 2027 and $475 million of its 3.95% First Mortgage Bonds due August 2047. An amount equal to the net proceeds will be used to finance capital expenditures, disbursed during the period from February 2, 2016 to February 1, 2017, with respect to investments in MidAmerican Energy's 551-megawatt Wind X and 2,000-megawatt Wind XI projects, which were previously financed with MidAmerican Energy's general funds.

In January 2017, MidAmerican Energy provided notice to holders of its $250 million of 5.95% Senior Notes due July 2017 that MidAmerican Energy would redeem such notes in full through optional redemption on February 27, 2017.

(22) Unaudited Quarterly Operating Results

	2016			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In millions)			
Operating revenue	$ 625	$ 584	$ 795	$ 621
Operating income	100	139	284	42
Net income	76	131	320	15

	2015			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In millions)			
Operating revenue	$ 722	$ 572	$ 680	$ 528
Operating income	100	112	208	29
Income from continuing operations	90	126	233	(3)
Income on discontinued operations	4	5	1	6
Net income	94	131	234	3

Quarterly data reflect seasonal variations common to a Midwest utility.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Managers and Member of
MidAmerican Funding, LLC
Des Moines, Iowa

We have audited the accompanying consolidated balance sheets of MidAmerican Funding, LLC and subsidiaries ("MidAmerican Funding") as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2016. Our audits also included MidAmerican Funding's financial statement schedules listed in the Index at Item 15(a)(ii). These financial statements and financial statement schedules are the responsibility of MidAmerican Funding's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States) and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. MidAmerican Funding is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of MidAmerican Funding's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of MidAmerican Funding, LLC and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

As discussed in Note 3 to the consolidated financial statements, MidAmerican Energy Company transferred its assets and liabilities of its unregulated retail services business to a subsidiary of its parent, Berkshire Hathaway Energy Company, on January 1, 2016.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 24, 2017

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2016	**2015**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 15	$ 103
Receivables, net	287	346
Income taxes receivable	9	104
Inventories	264	238
Other current assets	35	58
Total current assets	610	849
Property, plant and equipment, net	12,835	11,737
Goodwill	1,270	1,270
Regulatory assets	1,161	1,044
Investments and restricted cash and investments	655	636
Other assets	216	138
Total assets	$ 16,747	$ 15,674

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

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2016	**2015**
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities:		
Accounts payable	$ 302	$ 427
Accrued interest	52	53
Accrued property, income and other taxes	138	125
Note payable to affiliate	31	139
Short-term debt	99	—
Current portion of long-term debt	250	34
Other current liabilities	160	166
Total current liabilities	1,032	944
Long-term debt	4,377	4,563
Deferred income taxes	3,568	3,056
Regulatory liabilities	883	831
Asset retirement obligations	510	488
Other long-term liabilities	291	267
Total liabilities	10,661	10,149
Commitments and contingencies (Note 15)		
Member's equity:		
Paid-in capital	1,679	1,679
Retained earnings	4,407	3,876
Accumulated other comprehensive loss, net	—	(30)
Total member's equity	6,086	5,525
Total liabilities and member's equity	$ 16,747	$ 15,674

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

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2016	2015	2014
Operating revenue:			
Regulated electric	$ 1,985	$ 1,837	$ 1,817
Regulated gas and other	646	678	1,027
Total operating revenue	2,631	2,515	2,844
Operating costs and expenses:			
Cost of fuel, energy and capacity	409	433	532
Cost of gas sold and other	371	407	738
Operations and maintenance	694	707	720
Depreciation and amortization	479	407	351
Property and other taxes	112	110	108
Total operating costs and expenses	2,065	2,064	2,449
Operating income	566	451	395
Other income and (expense):			
Interest expense	(219)	(206)	(197)
Allowance for borrowed funds	8	8	16
Allowance for equity funds	19	20	39
Other, net	19	19	18
Total other income and (expense)	(173)	(159)	(124)
Income before income tax benefit	393	292	271
Income tax benefit	(139)	(150)	(122)
Income from continuing operations	532	442	393
Discontinued operations (Note 3):			
Income from discontinued operations	—	22	28
Income tax expense	—	6	12
Income on discontinued operations	—	16	16
Net income	$ 532	$ 458	$ 409

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

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2016	2015	2014
Net income	$ 532	$ 458	$ 409
Other comprehensive income (loss), net of tax:			
Unrealized gains on available-for-sale securities, net of tax of $1, $- and $1	3	—	1
Unrealized losses on cash flow hedges, net of tax of $-, $(4) and $(10)	—	(7)	(13)
Total other comprehensive income (loss), net of tax	3	(7)	(12)
Comprehensive income	$ 535	$ 451	$ 397

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

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Amounts in millions)

	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Total Equity
Balance, December 31, 2013	$ 1,679	$ 3,009	$ (11)	$ 4,677
Net income	—	409	—	409
Other comprehensive loss	—	—	(12)	(12)
Other equity transactions	—	(1)	—	(1)
Balance, December 31, 2014	1,679	3,417	(23)	5,073
Net income	—	458	—	458
Other comprehensive loss	—	—	(7)	(7)
Other equity transactions	—	1	—	1
Balance, December 31, 2015	1,679	3,876	(30)	5,525
Net income	—	532	—	532
Other comprehensive income	—	—	3	3
Transfer to affiliate (Note 3)	—	—	27	27
Other equity transactions	—	(1)	—	(1)
Balance, December 31, 2016	$ 1,679	$ 4,407	$ —	$ 6,086

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

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2016	**2015**	**2014**
Cash flows from operating activities:			
Net income	$ 532	$ 458	$ 409
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	479	407	351
Deferred income taxes and amortization of investment tax credits	362	276	298
Changes in other assets and liabilities	47	49	47
Other, net	(92)	(69)	(49)
Changes in other operating assets and liabilities:			
Receivables, net	(61)	93	(2)
Inventories	(27)	(53)	44
Derivative collateral, net	5	33	(53)
Contributions to pension and other postretirement benefit plans, net	(6)	(8)	(2)
Accounts payable	39	(76)	30
Accrued property, income and other taxes, net	107	213	(253)
Other current assets and liabilities	8	12	—
Net cash flows from operating activities	1,393	1,335	820
Cash flows from investing activities:			
Utility construction expenditures	(1,636)	(1,446)	(1,526)
Purchases of available-for-sale securities	(138)	(142)	(88)
Proceeds from sales of available-for-sale securities	158	135	80
Proceeds from sales of other investments	2	13	10
Other, net	—	2	5
Net cash flows from investing activities	(1,614)	(1,438)	(1,519)
Cash flows from financing activities:			
Proceeds from long-term debt	62	649	840
Repayments of long-term debt	(38)	(426)	(356)
Net change in note payable to affiliate	9	3	1
Net proceeds from (repayments of) short-term debt	99	(50)	50
Other, net	1	—	—
Net cash flows from financing activities	133	176	535
Net change in cash and cash equivalents	(88)	73	(164)
Cash and cash equivalents at beginning of year	103	30	194
Cash and cash equivalents at end of year	$ 15	$ 103	$ 30

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

(1) Company Organization

MidAmerican Funding, LLC ("MidAmerican Funding") is an Iowa limited liability company with Berkshire Hathaway Energy Company ("BHE") as its sole member. BHE is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway"). MidAmerican Funding's direct wholly owned subsidiary is MHC Inc. ("MHC"), which constitutes substantially all of MidAmerican Funding's assets, liabilities and business activities except those related to MidAmerican Funding's long-term debt securities. MHC conducts no business other than the ownership of its subsidiaries and related corporate services. MHC's principal subsidiary is MidAmerican Energy Company ("MidAmerican Energy"), a public utility with electric and natural gas operations. Direct, wholly owned nonregulated subsidiaries of MHC are Midwest Capital Group, Inc. ("Midwest Capital Group") and MEC Construction Services Co.

(2) Summary of Significant Accounting Policies

In addition to the following significant accounting policies, refer to Note 2 of MidAmerican Energy's Notes to Financial Statements for significant accounting policies of MidAmerican Funding.

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of MidAmerican Funding and its subsidiaries in which it held a controlling financial interest as of the financial statement date. Intercompany accounts and transactions have been eliminated, other than those between rate-regulated operations.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired when MidAmerican Funding purchased MHC. MidAmerican Funding evaluates goodwill for impairment at least annually and completed its annual review as of October 31. When evaluating goodwill for impairment, MidAmerican Funding estimates the fair value of the reporting unit. If the carrying amount of a reporting unit, including goodwill, exceeds the estimated fair value, then the identifiable assets, including identifiable intangible assets, and liabilities of the reporting unit are estimated at fair value as of the current testing date. The excess of the estimated fair value of the reporting unit over the current estimated fair value of net assets establishes the implied value of goodwill. The excess of the recorded goodwill over the implied goodwill value is charged to earnings as an impairment loss. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. MidAmerican Funding uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings; and an appropriate discount rate. In estimating future cash flows, MidAmerican Funding incorporates current market information, as well as historical factors. As such, the determination of fair value incorporates significant unobservable inputs. During 2016, 2015 and 2014, MidAmerican Funding did not record any goodwill impairments.

(3) Discontinued Operations

Refer to Note 3 of MidAmerican Energy's Notes to Financial Statements. The transfer of MidAmerican Energy's unregulated retail services business to a subsidiary of BHE repaid $117 million of MHC's note payable to BHE.

(4) Property, Plant and Equipment, Net

Refer to Note 4 of MidAmerican Energy's Notes to Financial Statements. In addition to MidAmerican Energy's property, plant and equipment, net, MidAmerican Funding had nonregulated property gross of $22 million as of December 31, 2016 and 2015, related accumulated depreciation and amortization of $9 million and $8 million as of December 31, 2016 and 2015, respectively, and construction work-in-progress of $1 million as of December 31, 2016, which consisted primarily of a corporate aircraft owned by MHC.

(5) Jointly Owned Utility Facilities

Refer to Note 5 of MidAmerican Energy's Notes to Financial Statements.

(6) Regulatory Matters

Refer to Note 6 of MidAmerican Energy's Notes to Financial Statements.

(7) Investments and Restricted Cash and Investments

Refer to Note 7 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K. In addition to MidAmerican Energy's investments and restricted cash and investments, MHC had corporate-owned life insurance policies in a Rabbi trust owned by MHC with a total cash surrender value of $2 million as of December 31, 2016 and 2015.

(8) Short-Term Debt and Credit Facilities

Refer to Note 8 of MidAmerican Energy's Notes to Financial Statements. In addition to MidAmerican Energy's credit facilities, MHC has a $4 million unsecured credit facility, which expires in June 2017 and has a variable interest rate based on LIBOR plus a spread. As of December 31, 2016 and 2015, there were no borrowings outstanding under this credit facility. As of December 31, 2016, MHC was in compliance with the covenants of its credit facility.

(9) Long-Term Debt

Refer to Note 9 of MidAmerican Energy's Notes to Financial Statements for detail and a discussion of its long-term debt. In addition to MidAmerican Energy's annual repayments of long-term debt, MidAmerican Funding has $325 million of long-term debt due in 2029, with a carrying value of $326 million as of December 31, 2016 and 2015.

MidAmerican Funding parent company long-term debt is secured by a pledge of the common stock of MHC. See Item 15(c) for the Consolidated Financial Statements of MHC Inc. and subsidiaries. The bonds are the direct senior secured obligations of MidAmerican Funding and effectively rank junior to all indebtedness and other liabilities of the direct and indirect subsidiaries of MidAmerican Funding, to the extent of the assets of these subsidiaries. MidAmerican Funding may redeem the bonds in whole or in part at any time at a redemption price equal to the sum of any accrued and unpaid interest to the date of redemption and the greater of (1) 100% of the principal amount of the bonds or (2) the sum of the present values of the remaining scheduled payments of principal and interest on the bonds, discounted to the date of redemption on a semiannual basis at the treasury yield plus 25 basis points.

Subsidiaries of MidAmerican Funding must make payments on their own indebtedness before making distributions to MidAmerican Funding. Refer to Note 9 of MidAmerican Energy's Notes to Financial Statements for a discussion of utility regulatory restrictions affecting distributions from MidAmerican Energy. As a result of the utility regulatory restrictions agreed to by MidAmerican Energy in March 1999, MidAmerican Funding had restricted net assets of $3.1 billion as of December 31, 2016.

As of December 31, 2016, MidAmerican Funding was in compliance with all of its applicable long-term debt covenants.

Each of MidAmerican Funding's direct or indirect subsidiaries is organized as a legal entity separate and apart from MidAmerican Funding and its other subsidiaries. It should not be assumed that any asset of any subsidiary of MidAmerican Funding will be available to satisfy the obligations of MidAmerican Funding or any of its other subsidiaries; provided, however, that unrestricted cash or other assets which are available for distribution may, subject to applicable law and the terms of financing arrangements of such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to MidAmerican Funding, one of its subsidiaries or affiliates thereof.

(10) Income Taxes

MidAmerican Funding's income tax benefit from continuing operations consists of the following for the years ended December 31 (in millions):

	2016	2015	2014
Current:			
Federal	$ (485)	$ (418)	$ (414)
State	(16)	(8)	(5)
	(501)	(426)	(419)
Deferred:			
Federal	367	282	296
State	(4)	(5)	2
	363	277	298
Investment tax credits	(1)	(1)	(1)
Total	$ (139)	$ (150)	$ (122)

A reconciliation of the federal statutory income tax rate MidAmerican Funding's the effective income tax rate applicable to income before income tax benefit from continuing operations is as follows for the years ended December 31:

	2016	2015	2014
Federal statutory income tax rate	35 %	35 %	35 %
Income tax credits	(64)	(72)	(68)
State income tax, net of federal income tax benefit	(3)	(3)	(1)
Effects of ratemaking	(3)	(12)	(10)
Other, net	—	1	(1)
Effective income tax rate	(35)%	(51)%	(45)%

Income tax credits relate primarily to production tax credits earned by MidAmerican Energy's wind-powered generating facilities. 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.

MidAmerican Funding's net deferred income tax liability consists of the following as of December 31 (in millions):

	2016	2015
Deferred income tax assets:		
Regulatory liabilities	$ 333	$ 327
Employee benefits	66	66
Asset retirement obligations	230	214
Other	82	97
Total deferred income tax assets	711	704
Deferred income tax liabilities:		
Depreciable property	(3,767)	(3,326)
Regulatory assets	(471)	(418)
Other	(41)	(16)
Total deferred income tax liabilities	(4,279)	(3,760)
Net deferred income tax liability	$ (3,568)	$ (3,056)

As of December 31, 2016, MidAmerican Funding has available $25 million of state tax carryforwards, principally related to $549 million of net operating losses, that expire at various intervals between 2017 and 2035.

The United States Internal Revenue Service has closed its examination of BHE's income tax returns through December 31, 2009, including components related to MidAmerican Funding. In addition, state jurisdictions have closed their examinations of MidAmerican Funding's income tax returns for Iowa through December 31, 2012, for Illinois through December 31, 2008, and for other jurisdictions through December 31, 2009.

A reconciliation of the beginning and ending balances of MidAmerican Funding's net unrecognized tax benefits is as follows for the years ended December 31 (in millions):

	2016	2015
Beginning balance	$ 10	$ 26
Additions based on tax positions related to the current year	—	4
Additions for tax positions of prior years	10	46
Reductions based on tax positions related to the current year	(2)	(6)
Reductions for tax positions of prior years	(8)	(46)
Statute of limitations	—	(5)
Settlements	—	(6)
Interest and penalties	—	(3)
Ending balance	$ 10	$ 10

As of December 31, 2016, MidAmerican Funding had unrecognized tax benefits totaling $30 million that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect MidAmerican Funding's effective income tax rate.

(11) Employee Benefit Plans

Refer to Note 11 of MidAmerican Energy's Notes to Financial Statements for additional information regarding MidAmerican Funding's pension, supplemental retirement and postretirement benefit plans.

Pension and postretirement costs allocated by MidAmerican Funding to its parent and other affiliates in each of the years ended December 31, were as follows (in millions):

	2016	2015	2014
Pension costs	$ 4	$ 4	$ 4
Other postretirement costs	(1)	(2)	(2)

(12) Asset Retirement Obligations

Refer to Note 12 of MidAmerican Energy's Notes to Financial Statements.

(13) Risk Management and Hedging Activities

Refer to Note 13 of MidAmerican Energy's Notes to Financial Statements.

(14) Fair Value Measurements

Refer to Note 14 of MidAmerican Energy's Notes to Financial Statements.

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

	2016		2015	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 4,627	$ 5,164	$ 4,597	$ 5,051

(15) Commitments and Contingencies

Refer to Note 15 of MidAmerican Energy's Notes to Financial Statements.

Legal Matters

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

(16) Components of Accumulated Other Comprehensive Loss, Net

Refer to Note 16 of MidAmerican Energy's Notes to Financial Statements.

(17) Other Income and (Expense) - Other, Net

Other, net, as shown on the Consolidated Statements of Operations, includes the following other income (expense) items for the years ended December 31 (in millions):

	2016	2015	2014
Corporate-owned life insurance income	$ 8	$ 4	$ 8
Gain on redemption of auction rate securities	5	—	—
Gains on sales of assets and other investments	3	13	—
Leveraged leases	—	1	5
Other, net	3	1	5
Total	$ 19	$ 19	$ 18

MidAmerican Funding recognized a $13 million pre-tax gain on the sale of an investment in a generating facility lease in 2015.

(18) Supplemental Cash Flow Information

The summary of supplemental cash flow information as of and for the years ending December 31 is as follows (in millions):

	2016	2015	2014
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 204	$ 177	$ 167
Income taxes received, net	$ 609	$ 630	$ 153
Supplemental disclosure of non-cash investing transactions:			
Accounts payable related to utility plant additions	$ 131	$ 249	$ 128
Transfer of assets and liabilities to affiliate (Note 3)	$ 90	$ —	$ —

(19) Related Party Transactions

The companies identified as affiliates of MidAmerican Funding are Berkshire Hathaway and its subsidiaries, including BHE and its subsidiaries. The basis for the following transactions is provided for in service agreements between MidAmerican Funding and the affiliates.

MidAmerican Funding is reimbursed for charges incurred on behalf of its affiliates. The majority of these reimbursed expenses are for allocated general costs, such as insurance and building rent, and for employee wages, benefits and costs for corporate functions, such as information technology, human resources, treasury, legal and accounting. The amount of such reimbursements was $35 million, $35 million and $37 million for 2016, 2015 and 2014, respectively.

MidAmerican Funding reimbursed BHE in the amount of $6 million, $7 million and $8 million in 2016, 2015 and 2014, respectively, for its share of corporate expenses.

MidAmerican Energy purchases natural gas transportation and storage capacity services from Northern Natural Gas Company, a wholly owned subsidiary of BHE, and coal transportation services from BNSF Railway Company, a wholly-owned subsidiary of Berkshire Hathaway, in the normal course of business at either tariffed or market prices. These purchases totaled $135 million, $165 million and $144 million in 2016, 2015 and 2014, respectively.

MHC has a $300 million revolving credit arrangement carrying interest at the 30-day LIBOR rate plus a spread to borrow from BHE. Outstanding balances are unsecured and due on demand. The outstanding balance was $31 million at an interest rate of 0.885% as of December 31, 2016, and $139 million at an interest rate of 0.494% as of December 31, 2015, and is reflected as note payable to affiliate on the Consolidated Balance Sheet.

BHE has a $100 million revolving credit arrangement, carrying interest at the 30-day LIBOR rate plus a spread to borrow from MHC. Outstanding balances are unsecured and due on demand. There were no borrowings outstanding throughout 2016 and 2015.

MidAmerican Funding had accounts receivable from affiliates of $7 million as of December 31, 2016 and 2015 that are included in receivables, net on the Consolidated Balance Sheets. MidAmerican Funding also had accounts payable to affiliates of $12 million as of December 31, 2016 and 2015, that are included in accounts payable on the Consolidated Balance Sheets.

MidAmerican Funding is party to a tax-sharing agreement and is part of the Berkshire Hathaway United States federal income tax return. For current federal and state income taxes, MidAmerican Funding had a payable to BHE of $7 million as of December 31, 2016, and a receivable from BHE of $102 million as of December 31, 2015. MidAmerican Funding received net cash receipts for federal and state income taxes from BHE totaling $609 million, $631 million and $154 million for the years ended December 31, 2016, 2015 and 2014, respectively.

MidAmerican Funding recognizes the full amount of the funded status for its pension and postretirement plans, and amounts attributable to MidAmerican Funding's affiliates that have not previously been recognized through income are recognized as an intercompany balance with such affiliates. MidAmerican Funding adjusts these balances when changes to the funded status of the respective plans are recognized and does not intend to settle the balances currently. Amounts receivable from affiliates attributable to the funded status of employee benefit plans totaled $12 million and $10 million as of December 31, 2016 and 2015, respectively, and similar amounts payable to affiliates totaled $36 million and $29 million as of December 31, 2016 and 2015, respectively. See Note 11 for further information pertaining to pension and postretirement accounting.

The indenture pertaining to MidAmerican Funding's long-term debt restricts MidAmerican Funding from paying a distribution on its equity securities, unless after making such distribution either its debt to total capital ratio does not exceed 0.67:1 and its interest coverage ratio is not less than 2.2:1 or its senior secured long-term debt rating is at least BBB or its equivalent. MidAmerican Funding may seek a release from this restriction upon delivery to the indenture trustee of written confirmation from the ratings agencies that without this restriction MidAmerican Funding's senior secured long-term debt would be rated at least BBB+.

(20) Segment Information

MidAmerican Funding has identified two reportable operating segments: regulated electric and regulated gas. The previously reported nonregulated energy segment consisted substantially of MidAmerican Energy's unregulated retail services business, which was transferred to a subsidiary of BHE and is excluded from the information below related to the statements of operations for all periods presented. The regulated electric segment derives most of its revenue from regulated retail sales of electricity to residential, commercial, and industrial customers and from wholesale sales. The regulated gas segment derives most of its revenue from regulated retail sales of natural gas to residential, commercial, and industrial customers and also obtains revenue by transporting gas owned by others through its distribution system. Pricing for regulated electric and regulated gas sales are established separately by regulatory agencies; therefore, management also reviews each segment separately to make decisions regarding allocation of resources and in evaluating performance. Common operating costs, interest income, interest expense and income tax expense are allocated to each segment based on certain factors, which primarily relate to the nature of the cost. "Other" in the tables below consists of the nonregulated subsidiaries of MidAmerican Funding not engaged in the energy business and parent company interest expense. Refer to Note 10 for a discussion of items affecting income tax (benefit) expense for the regulated electric and gas operating segments.

The following tables provide information on a reportable segment basis (in millions):

	Years Ended December 31, 2016	2015	2014
Operating revenue:			
Regulated electric	$ 1,985	$ 1,837	$ 1,817
Regulated gas	637	661	996
Other	9	17	31
Total operating revenue	$ 2,631	$ 2,515	$ 2,844
Depreciation and amortization:			
Regulated electric	$ 436	$ 366	$ 312
Regulated gas	43	41	39
Total depreciation and amortization	$ 479	$ 407	$ 351
Operating income:			
Regulated electric	$ 497	$ 385	$ 319
Regulated gas	68	64	75
Other	1	2	1
Total operating income	$ 566	$ 451	$ 395
Interest expense:			
Regulated electric	$ 178	$ 166	$ 157
Regulated gas	18	17	17
Other	23	23	23
Total interest expense	$ 219	$ 206	$ 197
Income tax (benefit) expense from continuing operations:			
Regulated electric	$ (156)	$ (163)	$ (138)
Regulated gas	22	16	22
Other	(5)	(3)	(6)
Total income tax (benefit) expense from continuing operations	$ (139)	$ (150)	$ (122)
Net income:			
Regulated electric	$ 512	$ 413	$ 361
Regulated gas	32	33	40
Other	(12)	(4)	(8)
Income from continuing operations	532	442	393
Income on discontinued operations	—	16	16
Net income	$ 532	$ 458	$ 409
Utility construction expenditures:			
Regulated electric	$ 1,564	$ 1,365	$ 1,429
Regulated gas	72	81	97
Total utility construction expenditures	$ 1,636	$ 1,446	$ 1,526

	As of December 31,		
	2016	2015	2014
Total assets:			
Regulated electric	$ 15,304	$ 14,161	$ 13,041
Regulated gas	1,424	1,330	1,296
Other	19	183	185
Total assets	$ 16,747	$ 15,674	$ 14,522

Goodwill by reportable segment as of December 31, 2016 and 2015, was as follows (in millions):

Regulated electric	$ 1,191
Regulated gas	79
Total	$ 1,270

(21) Subsequent Events

Refer to Note 21 of MidAmerican Energy's Notes to Financial Statements.

(22) Unaudited Quarterly Operating Results

	2016			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In millions)			
Operating revenue	$ 626	$ 585	$ 797	$ 623
Operating income	100	140	284	42
Net income	73	127	318	14

	2015			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In millions)			
Operating revenue	$ 727	$ 576	$ 681	$ 531
Operating income	101	112	209	29
Income from continuing operations	95	124	230	(7)
Income on discontinued operations	4	5	1	6
Net income	99	129	231	(1)

Quarterly data reflect seasonal variations common to a Midwest utility.

Nevada Power Company and its subsidiaries
Consolidated Financial Section

Item 6. Selected Financial Data

Information required by Item 6 is omitted pursuant to General Instruction I(2)(a) to Form 10-K.

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

General

Nevada Power's revenues and operating income are subject to fluctuations during the year due to impacts that seasonal weather, rate changes, and customer usage patterns have on demand for electric energy and resources. Nevada Power is a summer peaking utility experiencing its highest retail energy sales in response to the demand for air conditioning. The variations in energy usage due to varying weather, customer growth and other energy usage patterns, including energy efficiency and conservation measures, necessitates a continual balancing of loads and resources and purchases and sales of energy under short- and long-term energy supply contracts. As a result, the prudent management and optimization of available resources has a direct effect on the operating and financial performance of Nevada Power. Additionally, the timely recovery of purchased power, fuel costs and other costs and the ability to earn a fair return on investments through rates are essential to the operating and financial performance of Nevada Power.

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of Nevada Power 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 Nevada Power's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. Nevada Power's actual results in the future could differ significantly from the historical results.

Results of Operations

Net income for the year ended December 31, 2016 was $279 million, a decrease of $9 million, or 3%, compared to 2015. Net income decreased due to lower margins from changes in usage patterns with commercial and industrial customers, lower customer usage due to customer demand and the impacts of weather, benefits from changes in contingent liabilities in 2015 and higher depreciation and amortization primarily due to higher plant placed in-service. The decrease in net income was offset by higher customer growth and lower interest expense from the redemption of $210 million Series M, 5.950% General and Refunding Mortgage Notes in 2016.

Net income for the year ended December 31, 2015 was $288 million, an increase of $61 million, or 27%, compared to 2014. Net income increased primarily due to lower impairment costs resulting from the settlement of the 2014 regulatory rate review and certain assets not in rates of $31 million, higher electric margins from increased customer usage and growth and the impacts of weather of $28 million, lower other operating and maintenance of $35 million and lower interest expense of $18 million. The increase in net income was partially offset by higher depreciation and amortization of $23 million primarily due to higher regulatory amortizations.

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

A comparison of Nevada Power's key operating results related to gross margin for the years ended December 31 is as follows:

	2016	2015	Change		2015	2014	Change	
Gross margin (in millions):								
Operating revenue	$ 2,083	$ 2,402	$ (319)	(13)%	$ 2,402	$ 2,337	$ 65	3 %
Cost of fuel, energy and capacity	768	1,084	(316)	(29)	1,084	1,076	8	1
Gross margin	$ 1,315	$ 1,318	$ (3)	—	$ 1,318	$ 1,261	$ 57	5
GWh sold:								
Residential	9,394	9,246	148	2 %	9,246	8,923	323	4 %
Commercial	4,663	4,635	28	1	4,635	4,489	146	3
Industrial	7,313	7,571	(258)	(3)	7,571	7,486	85	1
Other	212	214	(2)	(1)	214	211	3	—
Total retail	21,582	21,666	(84)	—	21,666	21,109	557	3
Wholesale	258	353	(95)	(27)	353	20	333	*
Total GWh sold	21,840	22,019	(179)	(1)	22,019	21,129	890	4
Average number of retail customers (in thousands):								
Residential	796	782	14	2 %	782	770	12	2 %
Commercial	105	104	1	1	104	102	2	2
Industrial	2	2	—	—	2	2	—	—
Total	903	888	15	2	888	874	14	2
Average revenue per MWh -								
Retail	$ 94.27	$ 108.49	$ (14.22)	(13)%	$ 108.49	$ 108.90	$ (0.41)	— %
Heating degree days	1,508	1,491	17	1 %	1,491	1,306	185	14 %
Cooling degree days	4,002	4,069	(67)	(2)%	4,069	3,970	99	2 %
Sources of energy (GWh)(1):								
Coal	1,480	1,556	(76)	(5)%	1,556	4,422	(2,866)	(65)%
Natural gas	14,577	14,567	10	—	14,567	12,590	1,977	16
Other	61	4	57	*	4	15	(11)	(73)
Total energy generated	16,118	16,127	(9)	—	16,127	17,027	(900)	(5)
Energy purchased	6,462	6,431	31	—	6,431	5,424	1,007	19
Total	22,580	22,558	22	—	22,558	22,451	107	—
Average total cost of energy per MWh(2)	$ 34.00	$ 48.04	$ (14.04)	(29)%	$ 48.04	$ 47.94	$ 0.10	— %

* Not meaningful

(1) GWh amounts are net of energy used by the related generating facilities.

(2) The average total cost of energy per MWh includes the cost of fuel, purchased power and deferrals and does not include other costs.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Gross margin decreased $3 million for 2016 compared to 2015 due to:

- $9 million in usage patterns for commercial and industrial customers;
- $8 million due to lower customer usage, due to the impacts of weather; and
- $2 million in transmission revenue.

The decrease in gross margin was partially offset by:

- $16 million due to higher customer growth.

Operating and maintenance increased $22 million, or 6%, for 2016 compared to 2015 due to benefits from changes in contingent liabilities in 2015, higher generating costs and disallowances resulting from regulatory rate reviews.

Depreciation and amortization increased $6 million, or 2%, for 2016 compared to 2015 primarily due to higher plant placed in-service.

Property and other taxes increased $2 million, or 6%, for 2016 compared to 2015 due to a reduction in property tax abatements, offset by lower assessed property values.

Other income (expense) is favorable $8 million, or 5%, for 2016 compared to 2015 primarily due to lower interest expense from the redemption of $210 million Series M, 5.950% General and Refunding Mortgage Notes in 2016.

Income tax expense decreased $16 million, or 10%, for 2016 compared to 2015. The effective tax rate was 34% in 2016 and 36% in 2015. The decrease in the effective tax rate is primarily due to the qualified production activities deduction.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

Gross margin increased $57 million, or 5%, for 2015 compared to 2014 due to:

- $26 million in higher energy efficiency program rate revenue, which is offset in operating and maintenance expense;
- $14 million due to higher customer growth;
- $14 million due to higher customer usage, primarily due to the impacts of weather; and
- $3 million in transmission revenue primarily due to increased ON Line usage.

Operating and maintenance decreased $41 million, or 10%, for 2015 compared to 2014 due to $31 million of lower impairment costs resulting from the settlement of the regulatory rate review in 2014 and certain assets not in rates, $18 million of decreased amortizations for demand side management program costs, benefits from changes in contingent liabilities in 2015, a decrease related to the retirement of Reid Gardner Generating Station Units 1-3 and lower compensation costs. The decrease was offset by $35 million in ON Line lease expense and $26 million in higher energy efficiency program costs, which are fully recovered in operating revenue.

Depreciation and amortization increased $23 million, or 8%, for 2015 compared to 2014 due to higher regulatory amortizations as a result of the 2014 regulatory rate review effective January 2015 and the acquisition of Reid Gardner Generating Station Unit 4 in 2014.

Property and other taxes increased $3 million, or 9%, for 2015 compared to 2014 primarily due to a new state commerce tax.

Other income (expense) is favorable $21 million, or 11%, for 2015 compared to 2014 due to redemption of $250 million Series L, 5.875% General and Refunding Mortgage Notes in January 2015, increased allowance for borrowed and equity funds and higher interest on deferred charges.

Income tax expense increased $32 million, or 25%, for 2015 compared to 2014. The effective tax rate was 36% in 2015 and 2014.

Liquidity and Capital Resources

As of December 31, 2016, Nevada Power's total net liquidity was $679 million as follows (in millions):

Cash and cash equivalents	$	279
Credit facilities[(1)]		400
Total net liquidity	$	679
Credit facilities:		
Maturity dates		2018

(1) Refer to Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding Nevada Power's credit facility.

In January 2017, Nevada Power (1) issued a notice to the bondholders for the repurchase of the remaining outstanding amounts of its $38 million Pollution Control Revenue Bonds Series 2006 and $38 million Pollution Control Revenue Bonds Series 2006A and (2) redeemed the Pollution Control Revenue Bonds Series 2006A aggregate principal amount outstanding plus accrued interest with the use of cash on hand. In February 2017, Nevada Power redeemed the Pollution Control Revenue Bonds Series 2006 aggregate principal amount outstanding plus accrued interest with the use of cash on hand.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2016 and 2015 were $771 million and $892 million, respectively. The change was due to decreased collections from customers due to lower retail rates as a result of deferred energy adjustment mechanisms, a 2016 contribution to the pension plan and increased operating costs. The decrease was offset by the receipt of impact fees from MGM Resorts International and Wynn Las Vegas, lower payments for fuel costs, settlement payments of contingent liabilities in 2015 and higher collections from customers for renewable energy programs.

Net cash flows from operating activities for the years ended December 31, 2015 and 2014 were $892 million and $704 million, respectively. The change was due to deferred energy from lower fuel costs, increased customer growth and usage, higher collections of energy efficiency program costs and a payment in 2014 of the bill credit to customers as a result of the BHE Merger. The increase was offset by refunds to customers for renewable energy programs, timing of projects under long-term service agreements which are offset in investing activities, higher payments for asset retirement obligations and settlement payments of contingent liabilities.

The timing of Nevada Power's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods and assumptions for each payment date.

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. As a result of the Act, Nevada Power's cash flows from operations benefited in 2015 due to bonus depreciation on qualifying assets placed in-service

In December 2015, the Protecting Americans from Tax Hikes Act of 2015 ("PATH") was signed into law, extending bonus depreciation for qualifying property acquired and placed in-service before January 1, 2020 (bonus depreciation rates will be 50% for 2015-2017, 40% in 2018, and 30% in 2019), with an additional year for certain longer lived assets. Investment tax credits were extended and phased-down for solar projects that are under construction before the end of 2021 (investment tax credit rates are 30% through 2019, 26% in 2020 and 22% in 2021; they revert to the statutory rate of 10% thereafter). As a result of PATH, Nevada Power's cash flows from operations are expected to benefit due to bonus depreciation on qualifying assets placed in-service through 2019 and investment tax credits (once the net operating loss is fully utilized) earned on qualifying projects through 2021.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2016 and 2015 were $(335) million and $(301) million, respectively. The change was due to increased capital maintenance expenditures and proceeds received from the sale of assets and an equity investment in 2015.

Net cash flows from investing activities for the years ended December 31, 2015 and 2014 were $(301) million and $(371) million, respectively. The change was primarily due to the acquisition of the Las Vegas and Sun Peak Generating Stations in 2014, offset by construction of the Nellis Solar Array in 2015, timing of projects under long-term service agreements which are offset in operating activities and proceeds received from the sale of assets and an equity investment.

Financing Activities

Net cash flows from financing activities for the years ended December 31, 2016 and 2015 were $(693) million and $(275) million, respectively. The change was due to higher dividends paid to NV Energy, Inc., partially offset by lower repayments of long-term debt.

Net cash flows from financing activities for the years ended December 31, 2015 and 2014 were $(275) million and $(239) million, respectively. The change was due to repayments of long-term debt and capital lease obligations, offset by lower dividends paid to NV Energy, Inc.

Ability to Issue Debt

Nevada Power's ability to issue debt is primarily impacted by its financing authority from the PUCN. As of December 31, 2016, Nevada Power has financing authority from the PUCN consisting of the ability to: (1) issue long-term debt securities of up to $1.3 billion; (2) refinancing authority up to $1.3 billion of long-term debt securities; and (3) maintain a revolving credit facility of up to $1.3 billion. Nevada Power's revolving credit facility contains a financial maintenance covenant which Nevada Power was in compliance with as of December 31, 2016. In addition, certain financing agreements contain covenants which are currently suspended as Nevada Power's senior secured debt is rated investment grade. However, if Nevada Power's senior secured debt ratings fall below investment grade by either Moody's Investor Service or Standard & Poor's, Nevada Power would be subject to limitations under these covenants.

Ability to Issue General and Refunding Mortgage Securities

To the extent Nevada Power has the ability to issue debt under the most restrictive covenants in its financing agreements and has financing authority to do so from the PUCN, Nevada Power's ability to issue secured debt is limited by the amount of bondable property or retired bonds that can be used to issue debt under Nevada Power's indenture.

Nevada Power's indenture creates a lien on substantially all of Nevada Power's properties in Nevada. As of December 31, 2016, $8.9 billion of Nevada Power's assets were pledged. Nevada Power had the capacity to issue $3.2 billion of additional general and refunding mortgage securities as of December 31, 2016 determined on the basis of 70% of net utility property additions. Property additions include plant-in-service and specific assets in construction work-in-progress. The amount of bond capacity listed above does not include eligible property in construction work-in-progress. Nevada Power also has the ability to release property from the lien of Nevada Power's indenture on the basis of net property additions, cash or retired bonds. To the extent Nevada Power releases property from the lien of Nevada Power's indenture, it will reduce the amount of securities issuable under the indenture.

Future Uses of Cash

Capital Expenditures

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

Historical and forecasted capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, for the years ending December 31 are as follows (in millions):

	Historical			Forecasted		
	2014	2015	2016	2017	2018	2019
Generation development	$ 201	$ 45	$ 1	$ 79	$ —	$ 2
Distribution	107	102	144	102	119	111
Transmission system investment	19	63	30	12	19	35
Other	44	110	160	105	90	84
Total	$ 371	$ 320	$ 335	$ 298	$ 228	$ 232

Nevada Power's approved forecast capital expenditures include the following:

- Generation development investment includes the purchase of the remaining 25% interest in the Silverhawk generating facility in 2017. Nevada Power's cost for the remaining interest will total $77 million. In December 2015, the PUCN approved the purchase of the facility in Nevada Power's triennial IRP filing.
- Remaining investments relate to operating projects that consist of routine expenditures for transmission, distribution, generation and other infrastructure needed to serve existing and expected demand.

Contractual Obligations

Nevada Power has contractual cash obligations that may affect its consolidated financial condition. The following table summarizes Nevada Power's material contractual cash obligations as of December 31, 2016 (in millions):

	Payments Due by Periods				
	2017	2018 - 2019	2020 - 2021	2022 and Thereafter	Total
Long-term debt	$ —	$ 1,323	$ —	$ 1,292	$ 2,615
Interest payments on long-term debt(1)	165	250	153	1,270	1,838
Capital leases, including interest(2),(3)	12	25	30	44	111
ON Line financial lease, including interest(2)	44	87	89	767	987
Fuel and capacity contract commitments(1)	697	797	713	5,310	7,517
Fuel and capacity contract commitments (not commercially operable)(1)	7	43	73	683	806
Operating leases and easements(1)	9	17	14	51	91
Asset retirement obligations	20	18	15	43	96
Maintenance, service and other contracts(1)	118	76	73	75	342
Total contractual cash obligations	$ 1,072	$ 2,636	$ 1,160	$ 9,535	$ 14,403

(1) Not reflected on the Consolidated Balance Sheets.

(2) Interest is not reflected on the Consolidated Balance Sheets.

(3) Includes fuel and capacity contracts designated as a capital lease.

Nevada Power has other types of commitments that arise primarily from unused lines of credit, letters of credit or relate to construction and other development costs (Liquidity and Capital Resources included within this Item 7 and Note 6), uncertain tax positions (Note 10) and asset retirement obligations (Note 13), which have not been included in the above table because the amount and timing of the cash payments are not certain. Refer, where applicable, to the respective referenced note in Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Regulatory Matters

Nevada Power is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further discussion regarding Nevada Power's general regulatory framework and current regulatory matters.

Environmental Laws and Regulations

Nevada Power is subject to federal, state and local laws and regulations regarding air and water quality, RPS, 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 Nevada Power'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 and local agencies. Nevada Power 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. Environmental laws and regulations continue to evolve, and Nevada Power is unable to predict the impact of the changing laws and regulations on its operations and financial results. Refer to "Liquidity and Capital Resources" for discussion of Nevada Power's forecasted environmental-related capital expenditures.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for additional information regarding environmental laws and regulations and "Liquidity and Capital Resources" for Nevada Power's forecasted environmental-related capital expenditures.

Collateral and Contingent Features

Debt of Nevada Power is rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of Nevada Power's ability to, in general, meet the obligations of its issued debt. 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.

Nevada Power has no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments. Nevada Power's secured revolving credit facility does not require the maintenance of a minimum credit rating level in order to draw upon its availability. However, commitment fees and interest rates under the credit facility 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 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 December 31, 2016, 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 December 31, 2016, Nevada Power would have been required to post $70 million of additional collateral. Nevada Power'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 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for a discussion of Nevada Power's collateral requirements specific to Nevada Power's derivative contracts.

Inflation

Historically, overall inflation and changing prices in the economies where Nevada Power operates has not had a significant impact on Nevada Power's consolidated financial results. Nevada Power operates under a cost-of-service based rate structure administered by the PUCN and the FERC. Under this rate structure, Nevada Power is allowed to include prudent costs in its rates, including the impact of inflation after Nevada Power experiences cost increases. Fuel and purchase power costs are recovered through a balancing account, minimizing the impact of inflation related to these costs. Nevada Power attempts to minimize the potential impact of inflation on its operations through the use of periodic rate adjustments for fuel and energy costs, by employing prudent risk management and hedging strategies and by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances. There can be no assurance that such actions will be successful.

New Accounting Pronouncements

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

Critical Accounting Estimates

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

Accounting for the Effects of Certain Types of Regulation

Nevada Power prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Nevada Power defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

Nevada Power continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit Nevada Power's ability to recover its costs. Nevada Power believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss). Total regulatory assets were $1.0 billion and total regulatory liabilities were $453 million as of December 31, 2016. Refer to Nevada Power's Note 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Nevada Power's regulatory assets and liabilities.

Derivatives

Nevada Power is exposed to the impact of market fluctuations in commodity prices and interest rates. Nevada Power is principally exposed to electricity, natural gas and coal market fluctuations primarily through Nevada Power's obligation to serve retail customer load in its regulated service territory. Nevada Power's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. The actual cost of fuel and purchased power is recoverable through the deferred energy mechanism. Interest rate risk exists on variable-rate debt and future debt issuances.

Nevada Power has established a risk management process that is designed to identify, assess, manage, mitigate, monitor and report each of the various types of risk involved in its business. Nevada Power employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage its commodity price and interest rate risk. Nevada Power 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, Nevada Power may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate Nevada Power's exposure to interest rate risk. Nevada Power does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices. Refer to Nevada Power's Note 8 and 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Nevada Power's derivative contracts.

Measurement Principles

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by accounting principles generally accepted in the United States of America. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which Nevada Power transacts. When quoted prices for identical contracts are not available, Nevada Power uses forward price curves. Forward price curves represent Nevada Power's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. Interest rate swaps are valued using a financial model which utilizes observable inputs for similar instruments based primarily on market price curves.

Nevada Power bases its forward price curves upon internally developed models, with internal and external fundamental data inputs. Market price quotations for electricity and natural gas trading hubs are not as readily obtainable due to markets that are not active. Given that limited market data exists for these contracts, Nevada Power 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. The model incorporates a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing its assets and liabilities measured and reported at fair value. The determination of the fair value for derivative contracts not only includes counterparty risk, but also the impact of Nevada Power's nonperformance risk on its liabilities, which as of December 31, 2016, had an immaterial impact to the fair value of its derivative contracts. As such, Nevada Power considers its derivative contracts to be valued using Level 3 inputs. The assumptions used in these models are critical because any changes in assumptions could have a significant impact on the estimated fair value of the contracts. As of December 31, 2016, Nevada Power had a net derivative liability of $14 million related to contracts where Nevada Power uses internal models with significant unobservable inputs.

Classification and Recognition Methodology

Nevada Power's commodity derivative contracts are probable of inclusion in regulated rates, and changes in the estimated fair value of derivative contracts are recorded as regulatory assets. Accordingly, amounts are generally not recognized in earnings until the contracts are settled and the amounts are reflected in regulated rates. As of December 31, 2016, Nevada Power had $14 million recorded as a regulatory asset related to derivative contracts on the Consolidated Balance Sheets.

Impairment of Long-Lived Assets

Nevada Power evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2016, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

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

Income Taxes

In determining Nevada Power's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by Nevada Power's various regulatory jurisdictions. Nevada Power's income tax returns are subject to continuous examinations by federal, state and local income tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. Nevada Power recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement.

Although the ultimate resolution of Nevada Power's federal, state and local income tax examinations is uncertain, Nevada Power believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations, if any, is not expected to have a material impact on Nevada Power's consolidated financial results. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense on the Consolidated Statements of Operations. Refer to Nevada Power's Note 10 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Nevada Power's income taxes.

Changes in deferred income tax assets and liabilities that are associated with income tax benefits and expense for certain property-related basis differences and other various differences that Nevada Power is required to pass on to its customers are charged or credited directly to a regulatory asset or liability. As of December 31, 2016, these amounts were recognized as regulatory assets of $141 million and regulatory liabilities of $9 million, and will be included in regulated rates when the temporary differences reverse.

Revenue Recognition - Unbilled Revenue

Revenue is recognized as electricity is delivered or services are provided. The determination of customer billings is based on a systematic reading of meters. At the end of each month, energy provided to customers since their last billing is estimated, and the corresponding unbilled revenue is recorded. Unbilled revenue was $91 million as of December 31, 2016. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns, total volumes supplied to the system, line losses, economic impacts and composition of sales among customer classes. Estimates are reversed in the following month when actual revenue is recorded.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Price Risk

Nevada Power is exposed to the impact of market fluctuations in commodity prices and interest rates. Nevada Power is principally exposed to electricity, natural gas and coal market fluctuations primarily through Nevada Power's obligation to serve retail customer load in its regulated service territory. Nevada Power's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. The actual cost of fuel and purchased power is recoverable through the deferred energy mechanism. Interest rate risk exists on variable-rate debt and future debt issuances. Nevada Power does not engage in proprietary trading activities. To mitigate a portion of its commodity price risk, Nevada Power 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. Nevada Power does not hedge its commodity price risk, thereby exposing the unhedged portion to changes in market prices. Nevada Power's exposure to commodity price risk is generally limited by its ability to include commodity costs in regulated rates through its deferred energy mechanism, which is subject to disallowance and regulatory lag that occurs between the time the costs are incurred and when the costs are included in regulated rates, as well as the impact of any customer sharing resulting from cost adjustment mechanisms.

The table that follows summarizes Nevada Power's price risk on commodity contracts accounted for as derivatives, and shows the effects of a hypothetical 10% increase and 10% decrease in forward market prices by the expected volumes for these contracts as of that date. The selected hypothetical change does not reflect what could be considered the best or worst case scenarios (dollars in millions).

	Fair Value - Net Liability	Estimated Fair Value after Hypothetical Change in Price	
		10% increase	10% decrease
As of December 31, 2016:			
Commodity derivative contracts	$ (14)	$ (15)	$ (13)
As of December 31, 2015:			
Commodity derivative contracts	$ (18)	$ (20)	$ (16)

Nevada Power's commodity derivative contracts not designated as hedging contracts are recoverable from customers in regulated rates and, therefore, net unrealized gains and losses associated with interim price movements on commodity derivative contracts do not expose Nevada Power to earnings volatility. As of December 31, 2016 and 2015, a net regulatory asset of $14 million and $22 million, respectively, was recorded related to the net derivative liability of $14 million and $22 million, respectively. The settled cost of these commodity derivative contracts is generally included in regulated rates.

Interest Rate Risk

Nevada Power is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. Nevada Power manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, Nevada Power's fixed-rate long-term debt does not expose Nevada Power to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if Nevada Power were to reacquire all or a portion of these instruments prior to their maturity. The nature and amount of Nevada Power's short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 6 and 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of Nevada Power's short- and long-term debt.

As of December 31, 2016 and 2015, Nevada Power had short- and long-term variable-rate obligations totaling $76 million that expose Nevada Power to the risk of increased interest expense in the event of increases in short-term interest rates. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on Nevada Power's consolidated annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2016 and 2015.

Credit Risk

Nevada Power is 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 Nevada Power's counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, Nevada Power analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, Nevada Power enters 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, Nevada Power exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2016, Nevada Power's aggregate credit exposure from energy related transactions totaled $5 million, based on settlement and mark-to-market exposures, net of collateral. The majority of the exposure is comprised of one counterparty that is not rated by nationally recognized credit rating agencies.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Nevada Power Company
Las Vegas, Nevada

We have audited the accompanying consolidated balance sheets of Nevada Power Company and subsidiaries ("Nevada Power") as of December 31, 2016 and 2015, and the related consolidated statements of operations, changes in shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of Nevada Power's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. Nevada Power is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of Nevada Power's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Nevada Power Company and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 24, 2017

NEVADA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions, except share data)

	As of December 31,	
	2016	2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 279	$ 536
Accounts receivable, net	243	265
Inventories	73	80
Regulatory assets	20	—
Other current assets	38	46
Total current assets	653	927
Property, plant and equipment, net	6,997	6,996
Regulatory assets	1,000	1,057
Other assets	39	37
Total assets	$ 8,689	$ 9,017
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 187	$ 214
Accrued interest	50	54
Accrued property, income and other taxes	93	30
Regulatory liabilities	37	173
Current portion of long-term debt and financial and capital lease obligations	17	225
Customer deposits	78	58
Other current liabilities	39	28
Total current liabilities	501	782
Long-term debt and financial and capital lease obligations	3,049	3,060
Regulatory liabilities	416	304
Deferred income taxes	1,474	1,405
Other long-term liabilities	277	303
Total liabilities	5,717	5,854
Commitments and contingencies (Note 14)		
Shareholder's equity:		
Common stock - $1.00 stated value, 1,000 shares authorized, issued and outstanding	—	—
Other paid-in capital	2,308	2,308
Retained earnings	667	858
Accumulated other comprehensive loss, net	(3)	(3)
Total shareholder's equity	2,972	3,163
Total liabilities and shareholder's equity	$ 8,689	$ 9,017

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

NEVADA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2016	2015	2014
Operating revenue	$ 2,083	$ 2,402	$ 2,337
Operating costs and expenses:			
Cost of fuel, energy and capacity	768	1,084	1,076
Operating and maintenance	394	372	413
Depreciation and amortization	303	297	274
Property and other taxes	38	36	33
Total operating costs and expenses	1,503	1,789	1,796
Operating income	580	613	541
Other income (expense):			
Interest expense	(185)	(190)	(208)
Allowance for borrowed funds	4	3	1
Allowance for equity funds	2	4	1
Other, net	24	20	22
Total other income (expense)	(155)	(163)	(184)
Income before income tax expense	425	450	357
Income tax expense	146	162	130
Net income	$ 279	$ 288	$ 227

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

NEVADA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Amounts in millions, except shares)

	Common Stock		Other Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Total Shareholder's Equity
	Shares	Amount				
Balance, December 31, 2013	1,000	$ —	$ 2,308	$ 586	$ (4)	$ 2,890
Net income	—	—	—	227	—	227
Dividends declared	—	—	—	(230)	—	(230)
Other equity transactions	—	—	—	—	1	1
Balance, December 31, 2014	1,000	—	2,308	583	(3)	2,888
Net income	—	—	—	288	—	288
Dividends declared	—	—	—	(13)	—	(13)
Balance, December 31, 2015	1,000	—	2,308	858	(3)	3,163
Net income	—	—	—	279	—	279
Dividends declared	—	—	—	(469)	—	(469)
Other equity transactions	—	—	—	(1)	—	(1)
Balance, December 31, 2016	1,000	$ —	$ 2,308	$ 667	$ (3)	$ 2,972

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

NEVADA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2016	**2015**	**2014**
Cash flows from operating activities:			
Net income	$ 279	$ 288	$ 227
Adjustments to reconcile net income to net cash flows from operating activities:			
(Gain) loss on nonrecurring items	1	(3)	15
Depreciation and amortization	303	297	274
Deferred income taxes and amortization of investment tax credits	78	162	130
Allowance for equity funds	(2)	(4)	(1)
Changes in regulatory assets and liabilities	131	4	2
Deferred energy	(21)	176	(44)
Amortization of deferred energy	(107)	36	79
Other, net	—	13	68
Changes in other operating assets and liabilities:			
Accounts receivable and other assets	26	(40)	(19)
Inventories	7	9	(15)
Accrued property, income and other taxes	63	—	1
Accounts payable and other liabilities	13	(46)	(13)
Net cash flows from operating activities	771	892	704
Cash flows from investing activities:			
Capital expenditures	(335)	(320)	(371)
Proceeds from sale of assets	—	9	—
Other, net	—	10	—
Net cash flows from investing activities	(335)	(301)	(371)
Cash flows from financing activities:			
Repayments of long-term debt and financial and capital lease obligations	(224)	(262)	(9)
Dividends paid	(469)	(13)	(230)
Net cash flows from financing activities	(693)	(275)	(239)
Net change in cash and cash equivalents	(257)	316	94
Cash and cash equivalents at beginning of period	536	220	126
Cash and cash equivalents at end of period	$ 279	$ 536	$ 220

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

NEVADA POWER COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Operations

Nevada Power Company, together with its subsidiaries ("Nevada Power"), is a wholly owned subsidiary of NV Energy, Inc. ("NV Energy"), a holding company that also owns Sierra Pacific Power Company ("Sierra Pacific") and certain other subsidiaries. Nevada Power is a United States regulated electric utility company serving retail customers, including residential, commercial and industrial customers primarily in the Las Vegas, North Las Vegas, Henderson and adjoining areas. NV Energy is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company ("BHE"). BHE is a holding company based in Des Moines, Iowa that owns subsidiaries principally engaged in energy businesses. BHE is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of Nevada Power Company and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. Intercompany accounts and transactions have been eliminated. The Consolidated Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the years ended December 31, 2016, 2015 and 2014. Certain amounts in the prior period Consolidated Financial Statements have been reclassified to conform to the current period presentation. Such reclassifications did not impact previously reported operating income, net income or retained earnings.

Use of Estimates in Preparation of Financial Statements

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

Accounting for the Effects of Certain Types of Regulation

Nevada Power prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Nevada Power defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

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

Fair Value Measurements

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

Cash Equivalents and Restricted Cash and Investments

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

Allowance for Doubtful Accounts

Accounts receivable are stated at the outstanding principal amount, net of an estimated allowance for doubtful accounts. The allowance for doubtful accounts is based on Nevada Power's assessment of the collectibility of amounts owed to Nevada Power by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. Nevada Power also has the ability to assess deposits on customers who have delayed payments or who are deemed to be a credit risk. The change in the balance of the allowance for doubtful accounts, which is included in accounts receivable, net on the Consolidated Balance Sheets, is summarized as follows for the years ended December 31 (in millions):

	2016	2015	2014
Beginning balance	$ 13	$ 14	$ 8
Charged to operating costs and expenses, net	16	16	14
Write-offs, net	(17)	(17)	(8)
Ending balance	$ 12	$ 13	$ 14

Derivatives

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

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

For Nevada Power's derivative contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as regulatory assets and liabilities. For a derivative contract not probable of inclusion in rates, changes in the fair value are recognized in earnings.

Inventories

Inventories consist mainly of materials and supplies totaling $60 million and $58 million as of December 31, 2016 and 2015, respectively, and fuel, which includes coal stock, stored natural gas and fuel oil, totaling $13 million and $22 million as of December 31, 2016 and 2015, respectively. The cost is determined using the average cost method. Materials are charged to inventory when purchased and are expensed or capitalized to construction work in process, as appropriate, when used. Fuel costs are recovered from retail customers through the base tariff energy rates and deferred energy accounting adjustment charges approved by the Public Utilities Commission of Nevada ("PUCN").

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. Nevada Power capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include debt allowance for funds used during construction ("AFUDC"), and equity AFUDC, as applicable. The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed. The cost of repairs and minor replacements are charged to expense when incurred with the exception of costs for generation plant maintenance under certain long-term service agreements. Costs under these agreements are expensed straight-line over the term of the agreements as approved by the PUCN.

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

Generally when Nevada Power retires or sells a component of regulated property, plant and equipment depreciated using the composite method, it charges the original cost, net of any proceeds from the disposition, to accumulated depreciation. Any gain or loss on disposals of all other assets is recorded through earnings with the exception of material gains or losses on regulated property, plant and equipment depreciated on a straight-line basis, which is then recorded to a regulatory asset or liability.

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of regulated facilities, are capitalized as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. The rate applied to construction costs is the lower of the PUCN allowed rate of return and rates computed based on guidelines set forth by the Federal Energy Regulatory Commission ("FERC"). After construction is completed, Nevada Power is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets. Nevada Power's AFUDC rate used during 2016 and 2015 was 8.09%.

Asset Retirement Obligations

Nevada Power recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. Nevada Power's AROs are primarily associated with its generating facilities. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to property, plant and equipment, net) and for accretion of the ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability on the Consolidated Balance Sheets. The costs are not recovered in rates until the work has been completed.

Impairment of Long-Lived Assets

Nevada Power evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2016, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Income Taxes

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

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using estimated income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities that are associated with components of other comprehensive income ("OCI") are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities that are associated with income tax benefits and expense for certain property-related basis differences and other various differences that Nevada Power is required to pass on to its customers are charged or credited directly to a regulatory asset or liability. As of December 31, 2016 and 2015, these amounts were recognized as regulatory assets of $141 million and $149 million, respectively, and regulatory liabilities of $9 million and $10 million, respectively, and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized. Investment tax credits are generally deferred and amortized over the estimated useful lives of the related properties.

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

Revenue Recognition

Revenue is recognized as electricity is delivered or services are provided. Revenue recognized includes billed and unbilled amounts. As of December 31, 2016 and 2015, unbilled revenue was $91 million and $116 million, respectively, and is included in accounts receivable, net on the Consolidated Balance Sheets. Rates are established by regulators or contractual arrangements. When preliminary rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued. Nevada Power records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Consolidated Statements of Operations.

Nevada Power primarily buys energy and natural gas to satisfy its customer load requirements. Due to changes in retail customer load requirements, Nevada Power may not take physical delivery of the energy or natural gas. Nevada Power may sell the excess energy or natural gas to the wholesale market. In such instances, it is Nevada Power's policy to record such sales net in cost of fuel, energy and capacity.

Unamortized Debt Premiums, Discounts and Issuance Costs

Premiums, discounts and financing costs incurred for the issuance of long-term debt are amortized over the term of the related financing on a straight-line basis.

Segment Information

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

New Accounting Pronouncements

In November 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-18, which amends FASB Accounting Standards Codification ("ASC") Subtopic 230-10, "Statement of Cash Flows - Overall." The amendments in this guidance require that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. Nevada Power is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In August 2016, the FASB issued ASU No. 2016-15, which amends FASB ASC Topic 230, "Statement of Cash Flows." The amendments in this guidance address the classification of eight specific cash flow issues within the statement of cash flows with the objective of reducing the existing diversity in practice. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. Nevada Power is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements.

In February 2016, the FASB issued ASU No. 2016-02, which creates FASB ASC Topic 842, "Leases" and supersedes Topic 840 "Leases." This guidance increases transparency and comparability among entities by recording lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. A lessee should recognize in the balance sheet a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from previous guidance. This guidance is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted, and is required to be adopted using a modified retrospective approach. Nevada Power 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. During 2016, the FASB issued several ASUs that clarify the implementation guidance for ASU No. 2014-09 but do not change the core principle of the guidance. This guidance may be adopted retrospectively or under a modified retrospective method where the cumulative effect is recognized at the date of initial application. Nevada Power is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements. Nevada Power currently does not expect the timing and amount of revenue currently recognized to be materially different after adoption of the new guidance as a majority of revenue is recognized equal to what Nevada Power has the right to invoice as it corresponds directly with the value to the customer of Nevada Power's performance to date. Nevada Power's current plan is to quantitatively disaggregate revenue in the required financial statement footnote by customer class.

(3) Property, Plant and Equipment, Net

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

	Depreciable Life	2016	2015
Utility plant:			
Generation	30 - 55 years	$ 4,271	$ 4,212
Distribution	20 - 65 years	3,231	3,118
Transmission	45 - 65 years	1,846	1,788
General and intangible plant	5 - 65 years	738	694
Utility plant		10,086	9,812
Accumulated depreciation and amortization		(3,205)	(2,971)
Utility plant, net		6,881	6,841
Other non-regulated, net of accumulated depreciation and amortization	45 years	2	2
Plant, net		6,883	6,843
Construction work-in-progress		114	153
Property, plant and equipment, net		$ 6,997	$ 6,996

Almost all of Nevada Power's plant is subject to the ratemaking jurisdiction of the PUCN and the FERC. Nevada Power's depreciation and amortization expense, as authorized by the PUCN, stated as a percentage of the depreciable property balances as of December 31, 2016, 2015 and 2014 was 3.2%, 3.0% and 3.3%, respectively. Nevada Power is required to file a utility plant depreciation study every six years as a companion filing with the triennial general rate case filings.

Construction work-in-progress is related to the construction of regulated assets.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements, Nevada Power, as tenants in common, has undivided interests in jointly owned generation and transmission facilities. Nevada Power accounts for its proportionate share of each facility and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Consolidated Statements of Operations include Nevada Power's share of the expenses of these facilities. The amounts shown in the table below represent Nevada Power's share in each jointly owned facility as of December 31, 2016 (dollars in millions):

	Nevada Power's Share	Utility Plant	Accumulated Depreciation	Construction Work-in-Progress
Silverhawk Generating Station	75%	$ 248	$ 66	$ 3
Navajo Generating Station	11	213	145	2
ON Line Transmission Line	24	145	12	—
Other Transmission Facilities	Various	56	26	—
Total		$ 662	$ 249	$ 5

(5) Regulatory Matters

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

	Weighted Average Remaining Life	2016	2015
Deferred income taxes[1]	27 years	$ 141	$ 149
Merger costs from 1999 merger	28 years	136	143
Deferred operating costs	20 years	127	87
Decommissioning costs	7 years	114	121
Employee benefit plans[2]	10 years	105	98
Abandoned projects	3 years	75	91
Asset retirement obligations	7 years	74	79
Legacy meters	16 years	60	64
Merrill Lynch deferred energy costs	3 years	40	56
Other	Various	148	169
Total regulatory assets		$ 1,020	$ 1,057
Reflected as:			
Current assets		$ 20	$ —
Other assets		1,000	1,057
Total regulatory assets		$ 1,020	$ 1,057

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

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

Nevada Power had regulatory assets not earning a return on investment of $560 million and $572 million as of December 31, 2016 and 2015, respectively. The regulatory assets not earning a return on investment primarily consist of deferred income taxes, merger costs from 1999 merger, asset retirement obligations, deferred operating costs, a portion of the employee benefit plans, deferred energy costs and losses on reacquired debt.

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

	Weighted Average Remaining Life	2016	2015
Cost of removal[1]	33 years	$ 294	$ 273
Impact fees	6 years	90	—
Energy efficiency program	1 year	37	34
Deferred energy costs	1 year	—	139
Other	Various	32	31
Total regulatory liabilities		$ 453	$ 477
Reflected as:			
Current liabilities		$ 37	$ 173
Other long-term liabilities		416	304
Total regulatory liabilities		$ 453	$ 477

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

Deferred Energy

Nevada statutes permit regulated utilities to adopt deferred energy accounting procedures. The intent of these procedures is to ease the effect on customers of fluctuations in the cost of purchased natural gas, fuel and electricity and are subject to annual prudency review by the PUCN. Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates that excess is not recorded as a current expense on the Consolidated Statements of Operations but rather is deferred and recorded as a regulatory asset on the Consolidated Balance Sheets and would be included in the table above as deferred energy costs. Conversely, a regulatory liability is recorded to the extent fuel and purchased power costs recoverable through current rates exceed actual fuel and purchased power costs and is included in the table above as deferred energy costs. These excess amounts are reflected in quarterly adjustments to rates and recorded as cost of fuel, energy and capacity in future time periods.

Energy Efficiency Program Rates ("EEPR") and Energy Efficiency Implementation Rates ("EEIR")

EEPR was established to allow Nevada Power to recover the costs of implementing energy efficiency programs and EEIR was established to offset the negative impacts on revenue associated with the successful implementation of energy efficiency programs. These rates change once a year in the utility's annual DEAA application based on energy efficiency program budgets prepared by Nevada Power and approved by the PUCN in integrated resource plan proceedings. To the extent Nevada Power's earned rate of return exceeds the rate of return used to set base general rates, Nevada Power is required to refund to customers EEIR revenue previously collected for that year. In March 2016, Nevada Power filed an application to reset the EEIR and EEPR and refund the EEIR revenue received in 2015, including carrying charges. In July 2016, the PUCN issued an order accepting a stipulation requiring Nevada Power to refund the 2015 revenue and reset the rates as filed effective October 1, 2016. The EEIR liability for Nevada Power is $10 million and $18 million, which is included in current regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2016 and 2015, respectively.

Chapter 704B Applications

In May 2015, three customers, including MGM Resorts International ("MGM") and Wynn Las Vegas, LLC ("Wynn"), filed applications to purchase energy from alternative providers of a new electric resource and become distribution only service customers. In December 2015, the PUCN granted the applications subject to conditions, including paying an impact fee, on-going charges and receiving approval for specific alternative energy providers and terms. The costs associated with the impact fee and on-going charges were assessed to alleviate the burden on other Nevada Power customers for the applicants' share of previously committed investments and long-term renewable contracts. The impact fee is set on a case-by-case basis by the PUCN and at a level designed such that the remaining customers are not subjected to increased costs. In December 2015, the applicants filed petitions for reconsideration. In January 2016, the PUCN granted reconsideration and updated some of the terms, including removing a limitation related to energy purchased indirectly from NV Energy. In June 2016, MGM and Wynn made the required compliance filings and the PUCN issued orders allowing the customers to acquire electric energy and ancillary services from another energy supplier and become distribution only service customers of Nevada Power. The third customer did not proceed with purchasing energy from alternative providers. In September 2016, MGM and Wynn paid impact fees totaling $97 million. In October 2016, MGM and Wynn became distribution only service customers and started procuring energy from another energy supplier. In December 2016, as contemplated in the PUCN order, the impact fees were increased $2 million to reflect final energy costs for MGM and Wynn.

In September 2016, Switch, Ltd. ("Switch"), a customer of Nevada Power, filed an application with the PUCN to purchase energy from alternative providers of a new electric resource and become a distribution only service customer of Nevada Power. In December 2016, the PUCN approved a stipulation agreement that allowed Switch to purchase energy from alternative providers subject to conditions, including paying an impact fee in the Nevada Power service territory. Switch has provided notice that it intends to proceed with purchasing energy from alternative providers.

(6) Credit Facility

Nevada Power has a $400 million secured credit facility expiring in March 2018. The credit facility, which is for general corporate purposes for the issuance of letters of credit, has a variable interest rate based on London Interbank Offered Rate or a base rate, at Nevada Power's option, plus a spread that varies based on Nevada Power's credit ratings for its senior secured long-term debt securities. As of December 31, 2016 and 2015, Nevada Power had no borrowings outstanding under the credit facility. Amounts due under Nevada Power's credit facility are collateralized by Nevada Power's general and refunding mortgage bonds. The credit facility requires Nevada Power's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.68 to 1.0 as of the last day of each quarter.

(7) Long-Term Debt and Financial and Capital Lease Obligations

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

	Par Value	2016	2015
General and refunding mortgage securities:			
5.950% Series M, due 2016	—	—	210
6.500% Series O, due 2018	324	324	323
6.500% Series S, due 2018	499	498	498
7.125% Series V, due 2019	500	499	499
6.650% Series N, due 2036	367	357	356
6.750% Series R, due 2037	349	345	345
5.375% Series X, due 2040	250	247	247
5.450% Series Y, due 2041	250	236	235
Variable-rate series (2016-1.890% to 1.928%, 2015-0.672% to 1.055%):			
Pollution Control Revenue Bonds Series 2006A, due 2032	38	38	38
Pollution Control Revenue Bonds Series 2006, due 2036	38	37	37
Capital and financial lease obligations - 2.750% to 11.600%, due through 2054	485	485	497
Total long-term debt and financial and capital leases	$ 3,100	$ 3,066	$ 3,285
Reflected as:			
Current portion of long-term debt and financial and capital lease obligations		$ 17	$ 225
Long-term debt and financial and capital lease obligations		3,049	3,060
Total long-term debt and financial and capital leases		$ 3,066	$ 3,285

In January 2017, Nevada Power (1) issued a notice to the bondholders for the repurchase of the remaining outstanding amounts of its $38 million Pollution Control Revenue Bonds Series 2006 and $38 million Pollution Control Revenue Bonds Series 2006A and (2) redeemed the Pollution Control Revenue Bonds Series 2006A aggregate principal amount outstanding plus accrued interest with the use of cash on hand. In February 2017, Nevada Power redeemed the Pollution Control Revenue Bonds Series 2006 aggregate principal amount outstanding plus accrued interest with the use of cash on hand.

Annual Payment on Long-Term Debt and Financial and Capital Leases

The annual repayments of long-term debt and capital and financial leases for the years beginning January 1, 2017 and thereafter, are as follows (in millions):

	Long-term Debt	Capital and Financial Lease Obligations	Total
2017	$ —	$ 75	$ 75
2018	823	74	897
2019	500	76	576
2020	—	75	75
2021	—	79	79
Thereafter	1,292	831	2,123
Total	2,615	1,210	3,825
Unamortized premium, discount and debt issuance cost	(34)	—	(34)
Executory costs	—	(111)	(111)
Amounts representing interest	—	(614)	(614)
Total	$ 2,581	$ 485	$ 3,066

The issuance of General and Refunding Mortgage Securities by Nevada Power is subject to PUCN approval and is limited by available property and other provisions of the mortgage indentures. As of December 31, 2016, approximately $8.9 billion (based on original cost) of Nevada Power's property was subject to the liens of the mortgages.

Financial and Capital Lease Obligations

- In 1984, Nevada Power entered into a 30-year capital lease for the Pearson Building with five, five-year renewal options beginning in year 2015. In February 2010, Nevada Power amended this capital lease agreement to include the lease of the adjoining parking lot and to exercise three of the five-year renewal options beginning in year 2015. There remain two additional renewal options which could extend the lease an additional ten years. Capital assets of $25 million and $27 million were included in property, plant and equipment, net as of December 31, 2016 and 2015, respectively.
- In 2007, Nevada Power entered into a 20-year lease, with three 10-year renewal options, to occupy land and building for its Beltway Complex operations center in southern Nevada. Nevada Power accounts for the building portion of the lease as a capital lease and the land portion of the lease as an operating lease. Nevada Power transferred operations to the facilities in June 2009. Capital assets of $7 million were included in property, plant and equipment, net as of December 31, 2016 and 2015.
- Nevada Power has long-term energy purchase contracts which qualify as capital leases. The leases were entered into between the years 1989 and 1990 and became commercially operable through 1993. The terms of the leases are for 30 years and expire between the years 2022-2023. Capital assets of $38 million and $40 million were included in property, plant and equipment, net as of December 31, 2016 and 2015, respectively.
- Nevada Power has master leasing agreements of which various pieces of equipment qualify as capital leases. The remaining equipment is treated as operating leases. Lease terms average seven years under the master lease agreement. Capital assets of $1 million were included in property, plant and equipment, net as of December 31, 2016 and 2015.
- ON Line was placed in-service on December 31, 2013. The Nevada Utilities entered into a long-term transmission use agreement, in which the Nevada Utilities have 25% interest and Great Basin Transmission South, LLC has 75% interest. Refer to Note 4 for additional information. The Nevada Utilities' share of the long-term transmission use agreement and ownership interest is split at 95% for Nevada Power and 5% for Sierra Pacific. The term is for 41 years with the agreement ending December 31, 2054. Payments began on January 31, 2014. ON Line assets of $402 million and $410 million were included in property, plant and equipment, net as of December 31, 2016 and 2015, respectively.

(8) Risk Management and Hedging Activities

Nevada Power is exposed to the impact of market fluctuations in commodity prices and interest rates. Nevada Power is principally exposed to electricity, natural gas and coal market fluctuations primarily through Nevada Power's obligation to serve retail customer load in its regulated service territory. Nevada Power's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. The actual cost of fuel and purchased power is recoverable through the deferred energy mechanism. Interest rate risk exists on variable-rate debt and future debt issuances. Nevada Power does not engage in proprietary trading activities.

Nevada Power has established a risk management process that is designed to identify, assess, manage, mitigate, monitor and report each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, Nevada Power 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. Nevada Power 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, Nevada Power may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate Nevada Power's exposure to interest rate risk. Nevada Power does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in Nevada Power's accounting policies related to derivatives. Refer to Notes 2 and 9 for additional information on derivative contracts.

The following table, which excludes contracts that have been designated as normal under the normal purchases or normal sales exception afforded by GAAP, summarizes the fair value of Nevada Power'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 Liabilities	Other Long-term Liabilities	Total
As of December 31, 2016:			
Commodity derivative liabilities[1]	$ (7)	$ (7)	$ (14)
As of December 31, 2015:			
Commodity derivative liabilities[1]	$ (8)	$ (14)	$ (22)

(1) Nevada Power's commodity derivatives not designated as hedging contracts are included in regulated rates and as of December 31, 2016 and 2015, a regulatory asset of $14 million and $22 million, respectively, was recorded related to the derivative liability of $14 million and $22 million, respectively.

Derivative Contract Volumes

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

	Unit of Measure	2016	2015
Electricity sales	Megawatt hours	(2)	(2)
Natural gas purchases	Decatherms	114	126

Credit Risk

Nevada Power is 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 Nevada Power's counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, Nevada Power analyzes 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, Nevada Power enters 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, Nevada Power exercises 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 unsecured debt as reported by one or more of the three recognized credit rating agencies. These derivative contracts may either specifically provide rights to demand cash or other security in the event of a credit rating downgrade ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance," in the event of a material adverse change in creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2016, credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of Nevada Power's derivative contracts in liability positions with specific credit-risk-related contingent features was $2 million and $3 million as of December 31, 2016 and 2015, respectively, which represents the amount of collateral to be posted if all credit risk related contingent features for derivative contracts in liability positions had been triggered. Nevada Power's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation or other factors.

(9) Fair Value Measurements

The carrying value of Nevada Power'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. Nevada Power has various financial assets and liabilities that are measured at fair value on the Consolidated Balance Sheets 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 Nevada Power 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 Nevada Power's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. Nevada Power develops these inputs based on the best information available, including its own data.

The following table presents Nevada Power'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**	**Total**
As of December 31, 2016:				
Assets:				
Money market mutual funds[1]	$ 220	$ —	$ —	$ 220
Investment funds	6	—	—	6
	$ 226	$ —	$ —	$ 226
Liabilities - commodity derivatives	$ —	$ —	$ (14)	$ (14)
As of December 31, 2015:				
Assets - investment funds	$ 5	$ —	$ —	$ 5
Liabilities - commodity derivatives	$ —	$ —	$ (22)	$ (22)

(1) Amounts are included in cash and cash equivalents 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 Nevada Power transacts. When quoted prices for identical contracts are not available, Nevada Power uses forward price curves. Forward price curves represent Nevada Power's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. Nevada Power bases its forward price curves upon internally developed models, with internal and external fundamental data inputs. Market price quotations for certain electricity and natural gas trading hubs are not as readily obtainable due to markets that are not active. Given that limited market data exists for these contracts, Nevada Power uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The model incorporates a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing its assets and liabilities measured and reported at fair value. The determination of the fair value for derivative contracts not only includes counterparty risk, but also the impact of Nevada Power's nonperformance risk on its liabilities, which as of December 31, 2016, had an immaterial impact to the fair value of its derivative contracts. As such, Nevada Power considers its derivative contracts to be valued using Level 3 inputs. Refer to Note 8 for further discussion regarding Nevada Power's risk management and hedging activities.

Nevada Power's investments in money market mutual funds and equity securities are accounted for as available-for-sale securities and are stated at fair value. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value.

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

	2016	2015	2014
Beginning balance	$ (22)	$ (30)	$ (47)
Changes in fair value recognized in regulatory assets	(4)	—	9
Settlements	12	8	8
Ending balance	$ (14)	$ (22)	$ (30)

Nevada Power's long-term debt is carried at cost on the Consolidated Balance Sheets. The fair value of Nevada Power'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 Nevada Power'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 Nevada Power's long-term debt as of December 31 (in millions):

	2016		2015	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 2,581	$ 3,040	$ 2,788	$ 3,240

(10) Income Taxes

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

	2016	2015	2014
Current – Federal	$ 68	$ —	$ —
Deferred – Federal	79	163	131
Investment tax credits	(1)	(1)	(1)
Total income tax expense	$ 146	$ 162	$ 130

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

	2016	2015	2014
Federal statutory income tax rate	35%	35%	35%
Effects of ratemaking	—	1	1
Other	(1)	—	—
Effective income tax rate	34%	36%	36%

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

	2016	2015
Deferred income tax assets:		
Capital and financial leases	170	174
Regulatory liabilities	83	47
Employee benefits	29	30
Customer advances	23	22
Federal net operating loss and credit carryforwards	5	15
Other	16	17
Total deferred income tax assets	326	305
Valuation allowance	(5)	(5)
Total deferred income tax assets, net	321	300
Deferred income tax liabilities:		
Property related items	(1,293)	(1,242)
Regulatory assets	(321)	(275)
Capital and financial leases	(165)	(169)
Other	(16)	(19)
Total deferred income tax liabilities	(1,795)	(1,705)
Net deferred income tax liability	$ (1,474)	$ (1,405)

The following table provides Nevada Power's tax credit carryforwards and expiration dates as of December 31, 2016 (in millions):

Other tax credits	$ 5
Expiration dates	2017 - 2028

The United States federal jurisdiction is the only significant income tax jurisdiction for NV Energy. In July 2012, the United States Internal Revenue Service and the Joint Committee on Taxation concluded their examination of NV Energy with respect to its United States federal income tax returns for December 31, 2005 through December 31, 2008.

(11) Related Party Transactions

Kern River Gas Transmission Company, an indirect subsidiary of BHE, provided natural gas transportation and other services to Nevada Power of $68 million for each of the years ended December 31, 2016, 2015 and 2014. As of December 31, 2016 and 2015, Nevada Power's Consolidated Balance Sheets included amounts due to Kern River Gas Transmission Company of $5 million.

Nevada Power provided electricity and other services to PacifiCorp, an indirect subsidiary of BHE, of $2 million, $3 million and $3 million for the years ended December 31, 2016, 2015 and 2014, respectively. There were no receivables associated with these services as of December 31, 2016 and 2015. PacifiCorp provided electricity and the sale of renewable energy credits to Nevada Power of $- million, $2 million and $5 million for the years ended December 31, 2016, 2015 and 2014, respectively. There were no payables associated with these transactions as of December 31, 2016 and 2015.

Nevada Power provided electricity to Sierra Pacific of $78 million, $69 million and $33 million for the years ended December 31, 2016, 2015 and 2014, respectively. Receivables associated with these transactions were $45 million and $15 million as of December 31, 2016 and 2015, respectively. Nevada Power purchased electricity from Sierra Pacific of $17 million, $2 million and $8 million for the years ended December 31, 2016, 2015 and 2014, respectively. Payables associated with these transactions were $12 million and $1 million as of December 31, 2016 and 2015, respectively.

Nevada Power incurs intercompany administrative and shared facility costs with NV Energy and Sierra Pacific. These transactions are governed by an intercompany service agreement and are priced at cost. Nevada Power provided services to NV Energy of $1 million for each of the years ending December 31, 2016, 2015 and 2014. NV Energy provided services to Nevada Power of $10 million, $12 million and $19 million for the years ending December 31, 2016, 2015 and 2014, respectively. Nevada Power provided services to Sierra Pacific of $24 million, $22 million and $20 million for the years ended December 31, 2016, 2015 and 2014, respectively. Sierra Pacific provided services to Nevada Power of $14 million, $16 million and $16 million for the years ended December 31, 2016, 2015 and 2014, respectively. As of December 31, 2016 and 2015, Nevada Power's Consolidated Balance Sheets included amounts due to NV Energy of $32 million and $40 million, respectively. There were no receivables due from NV Energy as of December 31, 2016 and 2015. As of December 31, 2016 and 2015, Nevada Power's Consolidated Balance Sheets included receivables due from Sierra Pacific of $4 million and $6 million, respectively. There were no payables due to Sierra Pacific as of December 31, 2016 and 2015.

Nevada Power is party to a tax-sharing agreement with NV Energy and NV Energy is part of the Berkshire Hathaway United States federal income tax return. Federal income taxes payable to NV Energy were $68 million and $- million as of December 31, 2016 and 2015, respectively. No cash payments were made for federal income taxes for the years ended December 31, 2016, 2015 and 2014.

Certain disbursements for accounts payable and payroll are made by NV Energy on behalf of Nevada Power and reimbursed automatically when settled by the bank. These amounts are recorded as accounts payable at the time of disbursement.

(12) Retirement Plan and Postretirement Benefits

Nevada Power is a participant in benefit plans sponsored by NV Energy. The NV Energy Retirement Plan includes a qualified pension plan ("Qualified Pension Plan") and a supplemental executive retirement plan and a restoration plan (collectively, "Non-Qualified Pension Plans") that provide pension benefits for eligible employees. The NV Energy Comprehensive Welfare Benefit and Cafeteria Plan provides certain postretirement health care and life insurance benefits for eligible retirees ("Other Postretirement Plans") on behalf of Nevada Power. Nevada Power contributed $36 million, $- million and $- million to the Qualified Pension Plan for the year ended December 31, 2016, 2015 and 2014, respectively. Nevada Power did not make any contributions to the Non-Qualified Pension Plans or Other Postretirement Plans for the years ended December 31, 2016, 2015 and 2014. Amounts attributable to Nevada Power were allocated from NV Energy based upon the current, or in the case of retirees, previous, employment location. Offsetting regulatory assets and liabilities have been recorded related to the amounts not yet recognized as a component of net periodic benefit costs that will be included in regulated rates. Net periodic benefit costs not included in regulated rates are included in accumulated other comprehensive loss, net.

Amounts receivable from (payable to) NV Energy are included on the Consolidated Balance Sheets and consist of the following as of December 31 (in millions):

	2016	2015
Qualified Pension Plan -		
Other long-term liabilities	$ (24)	$ (38)
Non-Qualified Pension Plans:		
Other current liabilities	(1)	(1)
Other long-term liabilities	(9)	(9)
Other Postretirement Plans -		
Other long-term liabilities	(4)	(5)

(13) Asset Retirement Obligations

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

Nevada Power does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain generation, transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Consolidated Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled $294 million and $273 million as of December 31, 2016 and 2015, respectively.

The following table presents Nevada Power's ARO liabilities by asset type as of December 31 (in millions):

	2016	2015
Waste water remediation	$ 38	$ 42
Evaporative ponds and dry ash landfills	22	27
Asbestos	4	3
Solar	2	2
Other	17	11
Total asset retirement obligations	$ 83	$ 85

The following table reconciles the beginning and ending balances of Nevada Power's ARO liabilities for the years ended December 31 (in millions):

	2016	2015
Beginning balance	$ 85	$ 86
Change in estimated costs	4	3
Additions	—	3
Retirements	(10)	(11)
Accretion	4	4
Ending balance	$ 83	$ 85
Reflected as:		
Other current liabilities	$ 20	$ 13
Other long-term liabilities	63	72
	$ 83	$ 85

In 2008, Nevada Power signed an administrative order of consent as owner and operator of Reid Gardner Generating Station Unit Nos. 1, 2 and 3 and as co-owner and operating agent of Unit No. 4. Based on the administrative order of consent, Nevada Power recorded estimated AROs and capital remediation costs. However, actual costs of work under the administrative order of consent may vary significantly once the scope of work is defined and additional site characterization has been completed. In connection with the termination of the co-ownership arrangement, effective October 22, 2013, between Nevada Power and California Department of Water Resources ("CDWR") for the Reid Gardner Generating Station Unit No. 4, Nevada Power and CDWR entered into a cost-sharing agreement that sets forth how the parties will jointly share in costs associated with all investigation, characterization and, if necessary, remedial activities as required under the administrative order of consent.

Certain of Nevada Power's decommissioning and reclamation obligations relate to jointly-owned facilities, and as such, Nevada Power is committed to pay a proportionate share of the decommissioning or reclamation costs. In the event of a default by any of the other joint participants, the respective subsidiary may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. Management has identified legal obligations to retire generation plant assets specified in land leases for Nevada Power's jointly-owned Navajo Generating Station and the Higgins Generating Station. Provisions of the lease require the lessees to remove the facilities upon request of the lessors at the expiration of the leases. Nevada Power's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities in other long-term liabilities on the Consolidated Balance Sheets.

The 2015 change in estimated costs is primarily due to changes in the amount and timing of cash flows related to the implementation of the United States Environmental Protection Agency's ("EPA") 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. In addition to impacting existing AROs, the final rule also resulted in the recognition of additional AROs.

(14) Commitments and Contingencies

Environmental Laws and Regulations

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

Senate Bill 123

In June 2013, the Nevada State Legislature passed Senate Bill No. 123 ("SB 123"), which included the retirement of coal plants and replacing the capacity with renewable facilities and other generating facilities. In May 2014, Nevada Power filed its Emissions Reduction Capacity Replacement Plan ("ERCR Plan") in compliance with SB 123. In July 2015, Nevada Power filed an amendment to its ERCR Plan with the PUCN which was approved in September 2015. In June 2015, the Nevada State Legislature passed Assembly Bill No. 498, which modified the capacity replacement components of SB 123.

Consistent with the Emissions Reduction and Capacity Replacement Plan ("ERCR Plan"), Nevada Power acquired a 272-MW natural gas co-generating facility in 2014, acquired a 210-MW natural gas peaking facility in 2014, constructed a 15-MW solar photovoltaic facility in 2015 and contracted two renewable power purchase agreements with 100-MW solar photovoltaic generating facilities in 2015. In February 2016, Nevada Power solicited proposals to acquire 35 MW of nameplate renewable energy capacity to be owned by Nevada Power. Nevada Power did not enter into any agreements to acquire the 35 MW of nameplate renewable energy capacity; however, it has the option to acquire the 35 MW in the future under the ERCR Plan, subject to PUCN approval. In addition, Nevada Power was granted approval to purchase the remaining 130 MW of the Silverhawk natural gas-fueled combined cycle generating facility. In June 2016, Nevada Power executed a long-term power purchase agreement for 100 MW of nameplate renewable energy capacity in Nevada. In December 2016, the order was approved. In addition the order approved the early retirement of Reid Gardner Unit 4 in the first quarter of 2017. These transactions are related to Nevada Power's compliance with Senate Bill No. 123, resulting in the retirement of 812 MW of coal-fueled generation by 2019.

Reid Gardner Generation Station

In October 2011, Nevada Power received a request for information from the EPA Region 9 under Section 114 of the Clean Air Act requesting current and historical operations and capital project information for Nevada Power's Reid Gardner Generating Station located near Moapa, Nevada. The EPA's Section 114 information request does not allege any incidents of non-compliance at the plant, and there have been no other new enforcement-related proceedings that have been initiated by the EPA relating to the plant. Nevada Power completed its responses to the EPA during the first quarter of 2012 and will continue to monitor developments relating to this Section 114 request. At this time, Nevada Power cannot predict the impact, if any, associated with this information request.

Legal Matters

Nevada Power is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. Nevada Power 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.

Switch, Ltd.

In July 2016, Switch filed a complaint in the United States District Court for the District of Nevada against various parties, including Nevada Power. In September 2016, Switch filed an amended complaint. The amended complaint alleges that actions by the former general counsel of the PUCN, as well as the PUCN and the PUCN Staff, violated state and federal laws and as a result of those actions Switch was prevented from being able to utilize an alternative energy provider. Switch also alleges that Nevada Power was aware of the wrong doing and either participated in the activities or failed to take action to stop the wrong doing, and as a result Nevada Power has been improperly enriched by these activities. In addition, Switch asserted antitrust claims against Nevada Power. Switch was seeking monetary damages and to invalidate the settlement agreement between Switch and Nevada Power relating to Switch utilizing an alternative energy provider. In December 2016, the PUCN issued an order resolving the matters in the complaint. The order approved a stipulation between Switch and the Operations Staff of the PUCN, which allows Switch to purchase energy from alternative providers of a new electric resource and become a distribution only service customer. In January 2017, Switch voluntarily dismissed the federal court case with prejudice.

Commitments

Nevada Power has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2016 are as follows (in millions):

	2017	2018	2019	2020	2021	2022 and Thereafter	Total
Contract type:							
Fuel, capacity and transmission contract commitments	$ 697	$ 445	$ 352	$ 355	$ 358	$ 5,310	$ 7,517
Fuel and capacity contract commitments (not commercially operable)	7	14	29	36	37	683	806
Operating leases and easements	9	9	8	7	7	51	91
Maintenance, service and other contracts	118	39	37	37	36	75	342
Total commitments	$ 831	$ 507	$ 426	$ 435	$ 438	$ 6,119	$ 8,756

Fuel and Capacity Contract Commitments

Purchased Power

Nevada Power has several contracts for long-term purchase of electric energy which have been approved by the PUCN. The expiration of these contracts range from 2017 to 2067. Purchased power includes contracts which meet the definition of a lease. Nevada Power's operating and maintenance expense for purchase power contracts which met the lease criteria for 2016, 2015 and 2014 were $302 million, $264 million and $245 million, respectively, and are recorded as cost of fuel, energy and capacity on the Consolidated Statements of Operations.

Coal and Natural Gas

Nevada Power has a contract for the transportation of coal that extends through 2017. Additionally, gas transportation contracts expire from 2017 to 2032 and the gas supply contract expires in 2018.

Fuel and Capacity Contract Commitments - Not Commercially Operable

Nevada Power has several contracts for long-term purchase of electric energy in which the facility remains under development. Amounts represent the estimated payments under renewable energy power purchase contracts, which have been approved by the PUCN and are contingent upon the developers obtaining commercial operation and their ability to deliver power.

Operating Leases and Easements

Nevada Power has non-cancelable operating leases primarily for office equipment, office space, certain operating facilities, vehicles and land. These leases generally require Nevada Power to pay for insurance, taxes and maintenance applicable to the leased property. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. Nevada Power also has non-cancelable easements for land. Operating and maintenance expense on non-cancelable operating leases totaled \$13 million, \$11 million and \$10 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Maintenance, Service and Other Contracts

Nevada Power has long-term service agreements for the performance of maintenance on generation units. Obligation amounts are based on estimated usage. The estimated expiration of these service agreements range from 2017 to 2026.

(15) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2016	2015	2014
Supplemental disclosure of cash flow information -			
Interest paid, net of amounts capitalized	$ 173	$ 186	$ 194
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 19	$ 51	$ 30
Capital and financial lease obligations incurred	$ (1)	$ (5)	$ 7

(16) Unaudited Quarterly Operating Results (in millions)

	Three-Month Periods Ended			
	March 31, 2016	June 30, 2016	September 30, 2016	December 31, 2016
Operating revenues	$ 399	$ 525	$ 766	$ 393
Operating income	46	141	324	69
Net income	3	66	188	22

	Three-Month Periods Ended			
	March 31, 2015	June 30, 2015	September 30, 2015	December 31, 2015
Operating revenues	$ 459	$ 607	$ 878	$ 458
Operating income	74	136	329	74
Net income	24	60	187	17

Sierra Pacific Power Company and its subsidiaries
Consolidated Financial Section

Item 6. Selected Financial Data

Information required by Item 6 is omitted pursuant to General Instruction I(2)(a) to Form 10-K.

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

General

Sierra Pacific's revenues and operating income are subject to fluctuations during the year due to impacts that seasonal weather, rate changes, and customer usage patterns have on demand for electric energy, natural gas and resources. Sierra Pacific's electric segment is summer peaking experiencing its highest retail energy sales in response to the demand for air conditioning and its natural gas segment is winter peaking due to sales in response to the demand for heating. The variations in energy usage due to varying weather, customer growth and other energy usage patterns, including energy efficiency and conservation measures, necessitates a continual balancing of loads and resources and purchases and sales of energy under short- and long-term energy supply contracts. As a result, the prudent management and optimization of available resources has a direct effect on the operating and financial performance of Sierra Pacific. Additionally, the timely recovery of purchased power, fuel costs and other costs and the ability to earn a fair return on investments through rates are essential to the operating and financial performance of Sierra Pacific.

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of Sierra Pacific 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 Sierra Pacific's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. Sierra Pacific's actual results in the future could differ significantly from the historical results.

Results of Operations

Net income for the year ended December 31, 2016 was $84 million, an increase of $1 million, or 1%, compared to 2015. Net income increased due to a decrease in interest expense from financing transactions in 2016 of $8 million, increased customer growth and usage primarily due to the impacts of weather of $7 million and lower planned maintenance costs. The increase in net income was partially offset by disallowances resulting from the settlement of the regulatory rate review in 2016 of $5 million, higher depreciation and amortization primarily due to higher plant placed in-service of $5 million, a settlement payment associated with terminated transmission service in 2015 of $4 million and lower margins from a decrease in wholesale demand charges and changes in usage patterns with commercial and industrial customers.

Net income for the year ended December 31, 2015 was $83 million, a decrease of $4 million, or 5%, compared to 2014. Net income decreased due to higher planned maintenance costs of $10 million, higher depreciation and amortization of $8 million as a result of higher regulatory amortizations and lower interest and dividend income of $8 million. The decrease in net income is offset by an increase in margin from recovery of costs associated with advanced service delivery of $9 million, lower impairment costs resulting from the settlement of the companion filing made in conjunction with Nevada Power's regulatory rate review in 2014 of $8 million and a settlement payment associated with terminated transmission service of $4 million.

Operating revenue; cost of fuel, energy and capacity; and natural gas purchased for resale are key drivers of Sierra Pacific's results of operations as they encompass retail and wholesale electricity and natural gas revenue and the direct costs associated with providing electricity and natural gas to customers. Sierra Pacific believes that a discussion of gross margin, representing operating revenue less cost of fuel, energy and capacity and natural gas purchased for resale, is therefore meaningful.

Electric Gross Margin

A comparison of Sierra Pacific's key operating results related to regulated electric gross margin for the years ended December 31 is as follows:

	2016	2015	Change		2015	2014	Change	
Gross margin (in millions):								
Operating electric revenue	$ 702	$ 810	$ (108)	(13)%	$ 810	$ 779	$ 31	4 %
Cost of fuel, energy and capacity	265	374	(109)	(29)	374	361	13	4
Gross margin	$ 437	$ 436	$ 1	—	$ 436	$ 418	$ 18	4
GWh sold:								
Residential	2,375	2,315	60	3 %	2,315	2,268	47	2 %
Commercial	2,933	2,942	(9)	—	2,942	2,944	(2)	—
Industrial	3,014	2,973	41	1	2,973	2,869	104	4
Other	16	16	—	—	16	16	—	—
Total retail	8,338	8,246	92	1	8,246	8,097	149	2
Wholesale	662	664	(2)	—	664	645	19	3
Total GWh sold	9,000	8,910	90	1	8,910	8,742	168	2
Average number of retail customers (in thousands):								
Residential	291	288	3	1 %	288	285	3	1 %
Commercial	47	46	1	2	46	46	—	—
Total	338	334	4	1	334	331	3	1
Average revenue per MWh:								
Retail	$ 78.08	$ 90.85	$ (12.77)	(14)%	$ 90.85	$ 88.78	$ 2.07	2 %
Wholesale	$ 52.05	$ 61.37	$ (9.32)	(15)%	$ 61.37	$ 68.34	$ (6.97)	(10)%
Heating degree days	4,185	4,122	63	2 %	4,122	3,910	212	5 %
Cooling degree days	1,088	1,194	(106)	(9)%	1,194	1,211	(17)	(1)%
Sources of energy (GWh)(1):								
Coal	751	1,210	(459)	(38)%	1,210	1,870	(660)	(35)%
Natural gas	4,290	3,981	309	8	3,981	4,169	(188)	(5)
Total energy generated	5,041	5,191	(150)	(3)	5,191	6,039	(848)	(14)
Energy purchased	4,383	4,441	(58)	(1)	4,441	2,943	1,498	51
Total	9,424	9,632	(208)	(2)	9,632	8,982	650	7
Average total cost of energy per MWh(2)	$ 28.16	$ 38.80	$ (10.64)	(27)%	$ 38.80	$ 40.19	$ (1.39)	(3)%

(1) GWh amounts are net of energy used by the related generating facilities.

(2) The average total cost of energy per MWh includes the cost of fuel, purchased power and deferrals and does not include other costs.

Natural Gas Gross Margin

A comparison of key results related to regulated natural gas gross margin for the years ended December 31 is as follows:

	2016	2015	Change		2015	2014	Change	
Gross margin (in millions):								
Operating natural gas revenue	$ 110	$ 137	$ (27)	(20)%	$ 137	$ 125	$ 12	10%
Natural gas purchased for resale	55	84	(29)	(35)	84	76	8	11
Gross margin	$ 55	$ 53	$ 2	4	$ 53	$ 49	$ 4	8
Dth sold:								
Residential	9,207	8,649	558	6 %	8,649	7,921	728	9%
Commercial	4,679	4,198	481	11	4,198	3,921	277	7
Industrial	1,548	1,470	78	5	1,470	1,416	54	4
Total retail	15,434	14,317	1,117	8	14,317	13,258	1,059	8
Average number of retail customers (in thousands)	162	159	3	2 %	159	156	3	2%
Average revenue per retail Dth sold:	$ 7.13	$ 9.57	$ (2.44)	(25)%	$ 9.57	$ 9.43	$ 0.14	1%
Average cost of natural gas per retail Dth sold	$ 3.56	$ 5.87	$ (2.31)	(39)%	$ 5.87	$ 5.73	$ 0.14	2%
Heating degree days	4,185	4,122	63	2 %	4,122	3,910	212	5%

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Electric gross margin increased $1 million for 2016 compared to 2015 due to:

- $4 million in higher energy efficiency program rate revenue, which is offset in operating and maintenance expense;
- $3 million in higher customer growth; and
- $2 million in higher customer usage primarily due to the impacts of weather.

The increase in gross margin was offset by:

- $4 million related to a settlement payment associated with terminated transmission service in 2015;
- $2 million decrease in wholesale demand charges; and
- $2 million in usage patterns for commercial and industrial customers.

Natural gas gross margin increased $2 million, or 4%, for 2016 compared to 2015 primarily due to higher customer usage from the impacts of weather.

Operating and maintenance increased $3 million, or 2%, for 2016 compared to 2015 due to disallowances resulting from the settlement of the regulatory rate review in 2016 of $5 million and higher energy efficiency program costs, which are fully recovered in operating revenue, partially offset by decreased planned maintenance costs.

Depreciation and amortization increased $5 million, or 4%, for 2016 compared to 2015 primarily due to higher plant placed in-service.

Other income (expense) is favorable $7 million, or 13%, for 2016 compared to 2015 primarily due to a decrease in interest expense from financing transactions in 2016.

Income tax expense increased $2 million, or 4%, for 2016 compared to 2015. The effective tax rate was 37% for 2016 and 36% for 2015.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

Electric gross margin increased $18 million, or 4%, for 2015 compared to 2014 due to:

- $9 million from recovery of costs associated with advanced service delivery;
- $5 million in higher energy efficiency program rate revenue, which is offset in operating and maintenance expense; and
- $4 million related to a settlement payment associated with terminated transmission service.

Natural gas gross margin increased $4 million, or 8%, for 2015 compared to 2014 due to recovery of costs associated with advanced service delivery and an increase in customer usage in 2015, primarily due to the impacts of weather.

Operating and maintenance increased $5 million, or 3%, for 2015 compared to 2014 due to increased planned maintenance costs, higher energy efficiency program costs, which are fully recovered in operating revenue, and higher ON Line lease expense. This increase was partially offset by lower impairment costs resulting from the settlement of the companion filing made in conjunction with Nevada Power's regulatory rate review in 2014, lower costs related to relinquishing an insurance claim in 2014 for a previously sold asset and decreased compensation costs.

Depreciation and amortization increased $8 million, or 8%, for 2015 compared to 2014 primarily due to regulatory amortizations associated with advanced service delivery.

Property and other taxes increased $3 million, or 14%, for 2015 compared to 2014 due to an increase in assessed property values, higher franchise taxes and a new state commerce tax.

Other income (expense) is unfavorable $10 million, or 23%, for 2015 compared to 2014 primarily due to lower carrying charges related to the recovery of costs associated with advanced service delivery approved in the companion filing of the 2014 Nevada Power general rate case effective January 2015.

Income tax expense remained constant, for 2015 compared to 2014. The effective tax rate was 36% for 2015 and 35% for 2014. The increase in the effective tax rate is primarily due to the effects of ratemaking.

Liquidity and Capital Resources

As of December 31, 2016, Sierra Pacific's total net liquidity was $225 million as follows (in millions):

Cash and cash equivalents	$ 55
Credit facilities[1]	250
Less -	
Letters of credit and tax-exempt bond support	(80)
Net credit facilities	170
Total net liquidity	$ 225
Credit facilities:	
Maturity dates	2018

(1) Refer to Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding Sierra Pacific's credit facility.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2016 and 2015 were $243 million and $342 million, respectively. The change was due to decreased collections from customers due to lower retail rates as a result of deferred energy adjustment mechanisms, contributions to the pension plan and lower customer advances, partially offset by lower payments for fuel costs.

Net cash flows from operating activities for the years ended December 31, 2015 and 2014 were $342 million and $246 million, respectively. The change was due to deferred energy from lower fuel costs and higher collections, lower purchased power payments, timing of projects under long-term service agreements which are offset in investing activities, a payment in 2014 of the bill credit to customers as a result of the BHE Merger and a settlement payment associated with terminated transmission service. The increase was offset by higher refunds to customers for renewable energy programs and lower collections from customers due to usage and weather.

The timing of Sierra Pacific's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods and assumptions for each payment date.

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. As a result of the Act, Sierra Pacific's cash flows from operations benefited in 2015 due to bonus depreciation on qualifying assets placed in-service.

In December 2015, the Protecting Americans from Tax Hikes Act of 2015 ("PATH") was signed into law, extending bonus depreciation for qualifying property acquired and placed in-service before January 1, 2020 (bonus depreciation rates will be 50% for 2015-2017, 40% in 2018, and 30% in 2019), with an additional year for certain longer lived assets. As a result of PATH, Sierra Pacific's cash flows from operations are expected to benefit due to bonus depreciation on qualifying assets placed in-service through 2019.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2016 and 2015 were $(194) million and $(250) million, respectively. The change was primarily due to decreased capital expenditures.

Net cash flows from investing activities for the years ended December 31, 2015 and 2014 were $(250) million and $(186) million, respectively. The change was primarily due to an increase in capital expenditures relating to Tracy and Valmy Generating Stations including timing of projects under long-term service agreements which are offset in operating activities and the purchase of the general office building in Reno, Nevada.

Financing Activities

Net cash flows from financing activities for the years ended December 31, 2016 and 2015 were $(100) million and $(8) million, respectively. The change was due to financing transactions in 2016 and higher dividends paid to NV Energy, Inc.

Net cash flows from financing activities for the years ended December 31, 2015 and 2014 were $(8) million and $(105) million, respectively. The change was due to lower dividends paid to NV Energy, Inc.

Ability to Issue Debt

Sierra Pacific's ability to issue debt is primarily impacted by its financing authority from the PUCN. As of December 31, 2016, Sierra Pacific has financing authority from the PUCN consisting of the ability to: (1) issue additional long-term debt securities of up to $350 million; (2) refinance up to $55 million of long-term debt securities; and (3) maintain a revolving credit facility of up to $600 million. Sierra Pacific's revolving credit facility contains a financial maintenance covenant which Sierra Pacific was in compliance with as of December 31, 2016. In addition, certain financing agreements contain covenants which are currently suspended as Sierra Pacific's senior secured debt is rated investment grade. However, if Sierra Pacific's senior secured debt ratings fall below investment grade by either Moody's Investor Service or Standard & Poor's, Sierra Pacific would be subject to limitations under these covenants.

Ability to Issue General and Refunding Mortgage Securities

To the extent Sierra Pacific has the ability to issue debt under the most restrictive covenants in its financing agreements and has financing authority to do so from the PUCN, Sierra Pacific's ability to issue secured debt is limited by the amount of bondable property or retired bonds that can be used to issue debt under Sierra Pacific's indenture.

Sierra Pacific's indenture creates a lien on substantially all of Sierra Pacific's properties in Nevada. As of December 31, 2016, $3.8 billion of Sierra Pacific's assets were pledged. Sierra Pacific had the capacity to issue $1.2 billion of additional general and refunding mortgage securities as of December 31, 2016 determined on the basis of 70% of net utility property additions. Property additions include plant-in-service and specific assets in construction work-in-progress. The amount of bond capacity listed above does not include eligible property in construction work-in-progress. Sierra Pacific also has the ability to release property from the lien of Sierra Pacific's indenture on the basis of net property additions, cash or retired bonds. To the extent Sierra Pacific releases property from the lien of Sierra Pacific's indenture, it will reduce the amount of securities issuable under the indenture.

Future Uses of Cash

Capital Expenditures

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

Historical and forecasted capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, for the years ending December 31 are as follows (in millions):

	Historical			**Forecasted**		
	2014	**2015**	**2016**	**2017**	**2018**	**2019**
Generation development	$ 51	$ —	$ —	$ —	$ —	$ —
Distribution	89	86	115	101	74	73
Transmission system investment	19	38	12	20	44	24
Other	27	128	67	43	46	53
Total	$ 186	$ 252	$ 194	$ 164	$ 164	$ 150

Sierra Pacific’s forecast capital expenditures include investments that relate to operating projects that consist of routine expenditures for transmission, distribution, generation and other infrastructure needed to serve existing and expected demand.

Contractual Obligations

Sierra Pacific has contractual cash obligations that may affect its consolidated financial condition. The following table summarizes Sierra Pacific's material contractual cash obligations as of December 31, 2016 (in millions):

	Payments Due by Periods				
	2017	2018 - 2019	2020 - 2021	2022 and Thereafter	Total
Long-term debt	$ —	$ —	$ —	$ 1,121	$ 1,121
Interest payments on long-term debt[1]	40	79	79	379	577
Capital leases, including interest[2]	2	4	2	10	18
ON Line financial lease, including interest[2]	2	4	5	40	51
Fuel and capacity contract commitments[1]	238	259	133	375	1,005
Fuel and capacity contract commitments (not commercially operable)[1]	5	20	22	215	262
Operating leases and easements[1]	4	7	6	46	63
Asset retirement obligations	—	—	—	14	14
Maintenance, service and other contracts[1]	4	9	12	17	42
Total contractual cash obligations	$ 295	$ 382	$ 259	$ 2,217	$ 3,153

(1) Not reflected on the Consolidated Balance Sheets.

(2) Interest is not reflected on the Consolidated Balance Sheets.

Sierra Pacific has other types of commitments that arise primarily from unused lines of credit, letters of credit or relate to construction and other development costs (Liquidity and Capital Resources included within this Item 7 and Note 6), uncertain tax positions (Note 9) and asset retirement obligations (Note 12), which have not been included in the above table because the amount and timing of the cash payments are not certain. Refer, where applicable, to the respective referenced note in Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Regulatory Matters

Sierra Pacific is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further discussion regarding Sierra Pacific's general regulatory framework and current regulatory matters.

Environmental Laws and Regulations

Sierra Pacific is subject to federal, state and local laws and regulations regarding air and water quality, RPS, 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 Sierra Pacific'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 and local agencies. Sierra Pacific 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. Environmental laws and regulations continue to evolve, and Sierra Pacific is unable to predict the impact of the changing laws and regulations on its operations and financial results. Refer to "Liquidity and Capital Resources" for discussion of Sierra Pacific's forecasted environmental-related capital expenditures.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for additional information regarding environmental laws and regulations and "Liquidity and Capital Resources" for Sierra Pacific's forecasted environmental-related capital expenditures.

Collateral and Contingent Features

Debt of Sierra Pacific is rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of Sierra Pacific's ability to, in general, meet the obligations of its issued debt. 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.

Sierra Pacific has no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments. Sierra Pacific's secured revolving credit facility does not require the maintenance of a minimum credit rating level in order to draw upon its availability. However, commitment fees and interest rates under the credit facility 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 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 December 31, 2016, 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 December 31, 2016, Sierra Pacific would have been required to post $15 million of additional collateral. Sierra Pacific's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors.

Inflation

Historically, overall inflation and changing prices in the economies where Sierra Pacific operates has not had a significant impact on Sierra Pacific's consolidated financial results. Sierra Pacific operates under a cost-of-service based rate structure administered by the PUCN and the FERC. Under this rate structure, Sierra Pacific is allowed to include prudent costs in its rates, including the impact of inflation after Sierra Pacific experiences cost increases. Fuel and purchase power costs are recovered through a balancing account, minimizing the impact of inflation related to these costs. Sierra Pacific attempts to minimize the potential impact of inflation on its operations through the use of periodic rate adjustments for fuel and energy costs, by employing prudent risk management and hedging strategies and by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances. There can be no assurance that such actions will be successful.

New Accounting Pronouncements

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

Critical Accounting Estimates

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

Accounting for the Effects of Certain Types of Regulation

Sierra Pacific prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Sierra Pacific defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

Sierra Pacific continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit Sierra Pacific's ability to recover its costs. Sierra Pacific believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss). Total regulatory assets were $435 million and total regulatory liabilities were $290 million as of December 31, 2016. Refer to Sierra Pacific's Note 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Sierra Pacific's regulatory assets and liabilities.

Impairment of Long-Lived Assets

Sierra Pacific evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2016, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

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

Income Taxes

In determining Sierra Pacific's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by Sierra Pacific's various regulatory jurisdictions. Sierra Pacific's income tax returns are subject to continuous examinations by federal, state and local income tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. Sierra Pacific recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement. Although the ultimate resolution of Sierra Pacific's federal, state and local income tax examinations is uncertain, Sierra Pacific believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations, if any, is not expected to have a material impact on Sierra Pacific's consolidated financial results. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense on the Consolidated Statements of Operations. Refer to Sierra Pacific's Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Sierra Pacific's income taxes.

Changes in deferred income tax assets and liabilities that are associated with income tax benefits and expense for certain property-related basis differences and other various differences that Sierra Pacific is required to pass on to its customers are charged or credited directly to a regulatory asset or liability. As of December 31, 2016, these amounts were recognized as regulatory assets of $85 million and regulatory liabilities of $6 million, and will be included in regulated rates when the temporary differences reverse.

Revenue Recognition - Unbilled Revenue

Revenue is recognized as electricity or natural gas is delivered or services are provided. The determination of customer billings is based on a systematic reading of meters. At the end of each month, energy provided to customers since their last billing is estimated, and the corresponding unbilled revenue is recorded. Unbilled revenue was $52 million as of December 31, 2016. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns, total volumes supplied to the system, line losses, economic impacts and composition of sales among customer classes. Estimates are reversed in the following month when actual revenue is recorded.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Price Risk

Sierra Pacific is exposed to the impact of market fluctuations in commodity prices and interest rates. Sierra Pacific is principally exposed to electricity, natural gas and coal market fluctuations primarily through Sierra Pacific's obligation to serve retail customer load in its regulated service territory. Sierra Pacific's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity, 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. The actual cost of fuel and purchased power is recoverable through the deferred energy mechanism. Interest rate risk exists on variable-rate debt and future debt issuances. Sierra Pacific does not engage in proprietary trading activities. To mitigate a portion of its commodity price risk, Sierra Pacific 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. Sierra Pacific does not hedge its commodity price risk, thereby exposing the unhedged portion to changes in market prices. Sierra Pacific's exposure to commodity price risk is generally limited by its ability to include commodity costs in regulated rates through its deferred energy mechanism, which is subject to disallowance and regulatory lag that occurs between the time the costs are incurred and when the costs are included in regulated rates, as well as the impact of any customer sharing resulting from cost adjustment mechanisms.

Interest Rate Risk

Sierra Pacific is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. Sierra Pacific manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, Sierra Pacific's fixed-rate long-term debt does not expose Sierra Pacific to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if Sierra Pacific were to reacquire all or a portion of these instruments prior to their maturity. The nature and amount of Sierra Pacific's short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 6 and 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of Sierra Pacific's short- and long-term debt.

As of December 31, 2016 and 2015, Sierra Pacific had short- and long-term variable-rate obligations totaling $80 million and $214 million, respectively, that expose Sierra Pacific to the risk of increased interest expense in the event of increases in short-term interest rates. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on Sierra Pacific's consolidated annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2016 and 2015.

Credit Risk

Sierra Pacific is 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 Sierra Pacific's counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, Sierra Pacific analyzes the financial condition of each significant wholesale counterparty, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, Sierra Pacific enters 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, Sierra Pacific exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2016, Sierra Pacific's aggregate credit exposure from energy related transactions were not material, based on settlement and mark-to-market exposures, net of collateral.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Sierra Pacific Power Company
Las Vegas, Nevada

We have audited the accompanying consolidated balance sheets of Sierra Pacific Power Company and subsidiaries ("Sierra Pacific") as of December 31, 2016 and 2015, and the related consolidated statements of operations, changes in shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of Sierra Pacific's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. Sierra Pacific is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of Sierra Pacific's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Sierra Pacific Power Company and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 24, 2017

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions, except share data)

	As of December 31,	
	2016	**2015**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 55	$ 106
Accounts receivable, net	117	124
Inventories	45	39
Regulatory assets	25	—
Other current assets	13	13
Total current assets	255	282
Property, plant and equipment, net	2,822	2,766
Regulatory assets	410	432
Other assets	6	7
Total assets	$ 3,493	$ 3,487
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 146	$ 127
Accrued interest	14	15
Accrued property, income and other taxes	10	13
Regulatory liabilities	69	78
Current portion of long-term debt and financial and capital lease obligations	1	453
Customer deposits	16	17
Other current liabilities	12	11
Total current liabilities	268	714
Long-term debt and financial and capital lease obligations	1,152	749
Regulatory liabilities	221	230
Deferred income taxes	617	570
Other long-term liabilities	127	148
Total liabilities	2,385	2,411
Commitments and contingencies (Note 13)		
Shareholder's equity:		
Common stock - $3.75 stated value, 20,000,000 shares authorized and 1,000 issued and outstanding	—	—
Other paid-in capital	1,111	1,111
Accumulated deficit	(2)	(35)
Accumulated other comprehensive loss, net	(1)	—
Total shareholder's equity	1,108	1,076
Total liabilities and shareholder's equity	$ 3,493	$ 3,487

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

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2016	**2015**	**2014**
Operating revenue:			
Electric	$ 702	$ 810	$ 779
Natural gas	110	137	125
Total operating revenue	812	947	904
Operating costs and expenses:			
Cost of fuel, energy and capacity	265	374	361
Natural gas purchased for resale	55	84	76
Operating and maintenance	170	167	162
Depreciation and amortization	118	113	105
Property and other taxes	24	25	22
Total operating costs and expenses	632	763	726
Operating income	180	184	178
Other income (expense):			
Interest expense	(54)	(61)	(61)
Allowance for borrowed funds	4	2	2
Allowance for equity funds	(1)	2	3
Other, net	4	3	12
Total other income (expense)	(47)	(54)	(44)
Income before income tax expense	133	130	134
Income tax expense	49	47	47
Net income	$ 84	$ 83	$ 87

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

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Amounts in millions, except shares)

	Common Stock		Other Paid-in Capital	Accumulated Deficit	Accumulated Other Comprehensive Loss, Net	Total Shareholder's Equity
	Shares	Amount				
Balance, December 31, 2013	1,000	$ —	$ 1,111	$ (93)	$ (2)	$ 1,016
Net income	—	—	—	87	—	87
Dividends declared	—	—	—	(105)	—	(105)
Other equity transactions	—	—	—	—	—	—
Balance, December 31, 2014	1,000	—	1,111	(111)	(2)	998
Net income	—	—	—	83	—	83
Dividends declared	—	—	—	(7)	—	(7)
Other equity transactions	—	—	—	—	2	2
Balance, December 31, 2015	1,000	—	1,111	(35)	—	1,076
Net income	—	—	—	84	—	84
Dividends declared	—	—	—	(51)	—	(51)
Other equity transactions	—	—	—	—	(1)	(1)
Balance, December 31, 2016	1,000	$ —	$ 1,111	$ (2)	$ (1)	$ 1,108

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

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2016	2015	2014
Cash flows from operating activities:			
Net income	$ 84	$ 83	$ 87
Adjustments to reconcile net income to net cash flows from operating activities:			
Loss on nonrecurring items	5	—	14
Depreciation and amortization	118	113	105
Allowance for equity funds	1	(2)	(3)
Deferred income taxes and amortization of investment tax credits	49	47	47
Changes in regulatory assets and liabilities	(17)	(21)	(23)
Deferred energy	53	81	(30)
Amortization of deferred energy	(54)	17	19
Other, net	—	(9)	20
Changes in other operating assets and liabilities:			
Accounts receivable and other assets	7	15	28
Inventories	(6)	1	3
Accrued property, income and other taxes	(3)	—	—
Accounts payable and other liabilities	6	17	(21)
Net cash flows from operating activities	243	342	246
Cash flows from investing activities:			
Capital expenditures	(194)	(252)	(186)
Other, net	—	2	—
Net cash flows from investing activities	(194)	(250)	(186)
Cash flows from financing activities:			
Proceeds from issuance of long-term debt	1,089	—	—
Repayments of long-term debt and financial and capital lease obligations	(1,138)	(1)	1
Dividends paid	(51)	(7)	(105)
Other, net	—	—	(1)
Net cash flows from financing activities	(100)	(8)	(105)
Net change in cash and cash equivalents	(51)	84	(45)
Cash and cash equivalents at beginning of period	106	22	67
Cash and cash equivalents at end of period	$ 55	$ 106	$ 22

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

(1) Organization and Operations

Sierra Pacific Power Company, together with its subsidiaries ("Sierra Pacific"), is a wholly owned subsidiary of NV Energy, Inc. ("NV Energy"), a holding company that also owns Nevada Power Company ("Nevada Power") and certain other subsidiaries. Sierra Pacific is a United States regulated electric utility company serving retail customers, including residential, commercial and industrial customers and regulated retail natural gas customers primarily in northern Nevada. NV Energy is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company ("BHE"). BHE is a holding company based in Des Moines, Iowa that owns subsidiaries principally engaged in energy businesses. BHE is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of Sierra Pacific and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. Intercompany accounts and transactions have been eliminated. The Consolidated Statements of Comprehensive Income have been omitted as net income equals comprehensive income for the years ended December 31, 2016, 2015 and 2014. Certain amounts in the prior period Consolidated Financial Statements have been reclassified to conform to the current period presentation. Such reclassifications did not impact previously reported operating income, net income or retained earnings.

Use of Estimates in Preparation of Financial Statements

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

Accounting for the Effects of Certain Types of Regulation

Sierra Pacific prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Sierra Pacific defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

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

Fair Value Measurements

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

Cash Equivalents and Restricted Cash and Investments

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

Allowance for Doubtful Accounts

Accounts receivable are stated at the outstanding principal amount, net of an estimated allowance for doubtful accounts. The allowance for doubtful accounts is based on Sierra Pacific's assessment of the collectibility of amounts owed to Sierra Pacific by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. Sierra Pacific also has the ability to assess deposits on customers who have delayed payments or who are deemed to be a credit risk. The change in the balance of the allowance for doubtful accounts, which is included in accounts receivable, net on the Consolidated Balance Sheets, is summarized as follows for the years ended December 31 (in millions):

	2016	2015	2014
Beginning balance	$ 1	$ 2	$ 1
Charged to operating costs and expenses, net	2	1	2
Write-offs, net	(1)	(2)	(1)
Ending balance	$ 2	$ 1	$ 2

Derivatives

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

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

For Sierra Pacific's derivative contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as regulatory assets and liabilities. For a derivative contract not probable of inclusion in rates, changes in the fair value are recognized in earnings.

Inventories

Inventories consist mainly of materials and supplies totaling $36 million and $34 million as of December 31, 2016 and 2015, respectively, and fuel, which includes coal stock, stored natural gas and fuel oil, totaling $9 million and $5 million as of December 31, 2016 and 2015, respectively. The cost is determined using the average cost method. Materials are charged to inventory when purchased and are expensed or capitalized to construction work in process, as appropriate, when used. Fuel costs are recovered from retail customers through the base tariff energy rates and deferred energy accounting adjustment charges approved by the Public Utilities Commission of Nevada ("PUCN").

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. Sierra Pacific capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include debt allowance for funds used during construction ("AFUDC"), and equity AFUDC, as applicable. The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed. The cost of repairs and minor replacements are charged to expense when incurred with the exception of costs for generation plant maintenance under certain long-term service agreements. Costs under these agreements are expensed straight-line over the term of the agreements as approved by the PUCN.

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

Generally when Sierra Pacific retires or sells a component of regulated property, plant and equipment depreciated using the composite method, it charges the original cost, net of any proceeds from the disposition, to accumulated depreciation. Any gain or loss on disposals of all other assets is recorded through earnings with the exception of material gains or losses on regulated property, plant and equipment depreciated on a straight-line basis, which is then recorded to a regulatory asset or liability.

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of regulated facilities, are capitalized as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. The rate applied to construction costs is the lower of the PUCN allowed rate of return and rates computed based on guidelines set forth by the Federal Energy Regulatory Commission ("FERC"). After construction is completed, Sierra Pacific is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets. Sierra Pacific's AFUDC rate used during 2016 and 2015 was 7.62% for electric, 6.02% and 5.97% for natural gas, respectively, and 7.44% for common facilities.

Asset Retirement Obligations

Sierra Pacific recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. Sierra Pacific's AROs are primarily associated with its generating facilities. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to property, plant and equipment, net) and for accretion of the ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability on the Consolidated Balance Sheets. The costs are not recovered in rates until the work has been completed.

Impairment of Long-Lived Assets

Sierra Pacific evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2016, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Income Taxes

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

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using estimated income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities that are associated with components of other comprehensive income ("OCI") are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities that are associated with income tax benefits and expense for certain property-related basis differences and other various differences that Sierra Pacific is required to pass on to its customers are charged or credited directly to a regulatory asset or liability. As of December 31, 2016 and 2015, these amounts were recognized as regulatory assets of $85 million and $90 million, respectively, and regulatory liabilities of $6 million and $7 million, respectively, and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized. Investment tax credits are generally deferred and amortized over the estimated useful lives of the related properties.

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

Revenue Recognition

Revenue is recognized as electricity or natural gas is delivered or services are provided. Revenue recognized includes billed and unbilled amounts. As of December 31, 2016 and 2015, unbilled revenue was $52 million and $59 million, respectively, and is included in accounts receivable, net on the Consolidated Balance Sheets. Rates are established by regulators or contractual arrangements. When preliminary rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued. Sierra Pacific records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Consolidated Statements of Operations.

Sierra Pacific primarily buys energy and natural gas to satisfy its customer load requirements. Due to changes in retail customer load requirements, Sierra Pacific may not take physical delivery of the energy or natural gas. Sierra Pacific may sell the excess energy or natural gas to the wholesale market. In such instances, it is Sierra Pacific's policy to allocate the natural gas sales between generation and natural gas retail based on usage. The energy sales and natural gas sales allocated to generation are recorded net in cost of fuel, energy and capacity. The natural gas sales allocated to natural gas retail is recorded as wholesale revenue.

Unamortized Debt Premiums, Discounts and Issuance Costs

Premiums, discounts and financing costs incurred for the issuance of long-term debt are amortized over the term of the related financing on a straight-line basis.

New Accounting Pronouncements

In November 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-18, which amends FASB Accounting Standards Codification ("ASC") Subtopic 230-10, "Statement of Cash Flows - Overall." The amendments in this guidance require that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. Sierra Pacific is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In August 2016, the FASB issued ASU No. 2016-15, which amends FASB ASC Topic 230, "Statement of Cash Flows." The amendments in this guidance address the classification of eight specific cash flow issues within the statement of cash flows with the objective of reducing the existing diversity in practice. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted, and is required to be adopted retrospectively. Sierra Pacific is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements.

In February 2016, the FASB issued ASU No. 2016-02, which creates FASB ASC Topic 842, "Leases" and supersedes Topic 840 "Leases." This guidance increases transparency and comparability among entities by recording lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. A lessee should recognize in the balance sheet a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from previous guidance. This guidance is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted, and is required to be adopted using a modified retrospective approach. Sierra Pacific 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. During 2016, the FASB issued several ASUs that clarify the implementation guidance for ASU No. 2014-09 but do not change the core principle of the guidance. This guidance may be adopted retrospectively or under a modified retrospective method where the cumulative effect is recognized at the date of initial application. Sierra Pacific is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements. Sierra Pacific currently does not expect the timing and amount of revenue currently recognized to be materially different after adoption of the new guidance as a majority of revenue is recognized equal to what Sierra Pacific has the right to invoice as it corresponds directly with the value to the customer of Sierra Pacific's performance to date. Sierra Pacific's current plan is to quantitatively disaggregate revenue in the required financial statement footnote by segment and customer class.

(3) Property, Plant and Equipment, Net

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

	Depreciable Life	2016	2015
Utility plant:			
Electric generation	30 - 60 years	$ 1,137	$ 1,134
Electric distribution	20 - 70 years	1,417	1,382
Electric transmission	50 - 70 years	771	739
Electric general and intangible plant	5 - 65 years	164	139
Natural gas distribution	40 - 70 years	381	374
Natural gas general and intangible plant	5 - 60 years	15	13
Common general	5 - 65 years	267	265
Utility plant		4,152	4,046
Accumulated depreciation and amortization		(1,442)	(1,368)
Utility plant, net		2,710	2,678
Other non-regulated, net of accumulated depreciation and amortization	60 years	5	—
Plant, net		2,715	2,678
Construction work-in-progress		107	88
Property, plant and equipment, net		$ 2,822	$ 2,766

All of Sierra Pacific's plant is subject to the ratemaking jurisdiction of the PUCN and the FERC. Sierra Pacific's depreciation and amortization expense, as authorized by the PUCN, stated as a percentage of the depreciable property balances as of December 31, 2016, 2015 and 2014 was 3.0%, 2.9% and 3.0%, respectively. Sierra Pacific is required to file a utility plant depreciation study every six years as a companion filing with the triennial general rate case filings.

Construction work-in-progress is related to the construction of regulated assets.

During 2016, Sierra Pacific revised its electric and gas depreciation rates based on the results of a new depreciation study, the most significant impact of which was shorter estimated useful lives at the Valmy Generating Station. The effect of this change will increase depreciation and amortization expense by $9 million annually based on depreciable plant balances at the time of the change. However, the PUCN ordered the change relating to the Valmy Generating Station of $7 million annually be deferred for future recovery through a regulatory asset.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements, Sierra Pacific, as tenants in common, has undivided interests in jointly owned generation and transmission facilities. Sierra Pacific accounts for its proportionate share of each facility and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Consolidated Statements of Operations include Sierra Pacific's share of the expenses of these facilities. The amounts shown in the table below represent Sierra Pacific's share in each jointly owned facility as of December 31, 2016 (dollars in millions):

	Sierra Pacific's Share	Utility Plant	Accumulated Depreciation	Construction Work-in-Progress
Valmy Generating Station	50%	$ 389	$ 216	$ 1
ON Line Transmission Line	1	8	1	—
Valmy Transmission	50	4	2	—
Total		$ 401	$ 219	$ 1

(5) Regulatory Matters

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

	Weighted Average Remaining Life	2016	2015
Employee benefit plans[1]	10 years	$ 128	$ 126
Deferred income taxes[2]	27 years	85	90
Merger costs from 1999 merger	30 years	80	83
Abandoned projects	9 years	39	44
Renewable energy programs	1 year	25	—
Losses on reacquired debt	17 years	22	22
Other	Various	56	67
Total regulatory assets		$ 435	$ 432
Reflected as:			
Current assets		$ 25	$ —
Other assets		410	432
Total regulatory assets		$ 435	$ 432

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

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

Sierra Pacific had regulatory assets not earning a return on investment of $305 million and $254 million as of December 31, 2016 and 2015, respectively. The regulatory assets not earning a return on investment primarily consist of deferred income taxes, merger costs from 1999 merger, a portion of the employee benefit plans, losses on reacquired debt, legacy meters, a portion of abandoned projects and asset retirement obligations.

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

	Weighted Average Remaining Life	2016	2015
Cost of removal[1]	39 years	$ 205	$ 208
Deferred energy costs	1 year	64	66
Renewable energy program	1 year	—	8
Other	Various	21	26
Total regulatory liabilities		$ 290	$ 308
Reflected as:			
Current liabilities		$ 69	$ 78
Other long-term liabilities		221	230
Total regulatory liabilities		$ 290	$ 308

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

Deferred Energy

Nevada statutes permit regulated utilities to adopt deferred energy accounting procedures. The intent of these procedures is to ease the effect on customers of fluctuations in the cost of purchased natural gas, fuel and electricity and are subject to annual prudency review by the PUCN. Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates that excess is not recorded as a current expense on the Consolidated Statements of Operations but rather is deferred and recorded as a regulatory asset on the Consolidated Balance Sheets and would be included in the table above as deferred energy costs. Conversely, a regulatory liability is recorded to the extent fuel and purchased power costs recoverable through current rates exceed actual fuel and purchased power costs and is included in the table above as deferred energy costs. These excess amounts are reflected in quarterly adjustments to rates and recorded as cost of fuel, energy and capacity in future time periods.

General Rate Cases

In June 2016, Sierra Pacific filed an electric regulatory rate review with the PUCN. The filing requested no incremental annual revenue relief. In October 2016, Sierra Pacific filed with the PUCN a settlement agreement resolving most, but not all, issues in the proceeding and reduced Sierra Pacific's electric revenue requirement by $3 million spread evenly to all rate classes. In December 2016, the PUCN approved the settlement agreement and established an additional six MW of net metering capacity under the grandfathered rates, which are those net metering rates that were in effect prior to January 2016; the order establishes cost-based rates and a value-based excess energy credit for customers who choose to install private generation after the six MW limitation is reached. The new rates were effective January 1, 2017. In January 2017, Sierra Pacific filed a petition for reconsideration relating to the creation of the additional six MW of net metering at the grandfathered rates. Sierra Pacific believes the effects of the PUCN decision result in additional cost shifting to non-net metering customers and reduces the stipulated rate reduction for other customer classes.

In June 2016, Sierra Pacific filed a gas regulatory rate review with the PUCN. The filing requested a slight decrease in its incremental annual revenue requirement. In October 2016, Sierra Pacific filed with the PUCN a settlement agreement resolving all issues in the proceeding and reduced Sierra Pacific's gas revenue requirement by $2 million. In December 2016, the PUCN approved the settlement agreement. The new rates were effective January 1, 2017.

Energy Efficiency Program Rates ("EEPR") and Energy Efficiency Implementation Rates ("EEIR")

EEPR was established to allow Sierra Pacific to recover the costs of implementing energy efficiency programs and EEIR was established to offset the negative impacts on revenue associated with the successful implementation of energy efficiency programs. These rates change once a year in the utility's annual DEAA application based on energy efficiency program budgets prepared by Sierra Pacific and approved by the PUCN in integrated resource plan proceedings. To the extent Sierra Pacific's earned rate of return exceeds the rate of return used to set base general rates, Sierra Pacific is required to refund to customers EEIR revenue previously collected for that year. In March 2016, Sierra Pacific filed an application to reset the EEIR and EEPR and refund the EEIR revenue received in 2015, including carrying charges. In July 2016, the PUCN issued an order accepting a stipulation requiring Sierra Pacific to refund the 2015 revenue and reset the rates as filed effective October 1, 2016. The EEIR liability for Sierra Pacific is $2 million and $3 million, which is included in current regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2016 and 2015, respectively.

Chapter 704B Applications

In September 2016, Switch, Ltd. ("Switch"), a customer of Sierra Pacific, filed an application with the PUCN to purchase energy from alternative providers of a new electric resource and become a distribution only service customer of Sierra Pacific. In December 2016, the PUCN approved a stipulation agreement that allowed Switch to purchase energy from alternative providers. Switch has provided notice that it intends to proceed with purchasing energy from alternative providers.

(6) Credit Facility

The following table summarizes Sierra Pacific's availability under its credit facilities as of December 31 (in millions):

	2016	2015
Credit facilities	$ 250	$ 250
Less - Water Facilities Refunding Revenue Bond support	(80)	—
Net credit facilities	$ 170	$ 250

Sierra Pacific has a $250 million secured credit facility expiring in March 2018. The credit facility, which is for general corporate purposes for the issuance of letters of credit, has a variable interest rate based on London Interbank Offered Rate or a base rate, at Sierra Pacific's option, plus a spread that varies based on Sierra Pacific's credit ratings for its senior secured long-term debt securities. Amounts due under Sierra Pacific's credit facility are collateralized by Sierra Pacific's general and refunding mortgage bonds. The credit facility requires Sierra Pacific's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.68 to 1.0 as of the last day of each quarter.

(7) Long-Term Debt and Financial and Capital Lease Obligations

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

	Par Value	2016	2015
General and refunding mortgage securities:			
6.000% Series M, due 2016	$ —	$ —	$ 450
3.375% Series T, due 2023	250	248	248
2.600% Series U, due 2026	400	395	—
6.750% Series P, due 2037	252	255	255
Tax-exempt refunding revenue bond obligations:			
Fixed-rate series:			
1.250% Pollution Control Series 2016A, due 2029(1)	20	20	—
1.500% Gas Facilities Series 2016A, due 2031(1)	58	58	—
3.000% Gas and Water Series 2016B, due 2036(2)	60	64	—
Variable-rate series (2016-0.788% to 0.800%, 2015-0.733% to 1.054%):			
Pollution Control Series 2006A, due 2031	—	—	58
Pollution Control Series 2006B, due 2036	—	—	74
Pollution Control Series 2006C, due 2036	—	—	80
Water Facilities Series 2016C, due 2036	30	29	—
Water Facilities Series 2016D, due 2036	25	25	—
Water Facilities Series 2016E, due 2036	25	25	—
Capital and financial lease obligations - 2.700% to 10.130%, due through 2054	34	34	37
Total long-term debt and financial and capital leases	$ 1,154	$ 1,153	$ 1,202
Reflected as:			
Current portion of long-term debt and financial and capital lease obligations		$ 1	$ 453
Long-term debt and financial and capital lease obligations		1,152	749
Total long-term debt and financial and capital leases		$ 1,153	$ 1,202

(1) Subject to mandatory purchase by Sierra Pacific in June 2019 at which date the interest rate may be adjusted from time to time.

(2) Subject to mandatory purchase by Sierra Pacific in June 2022 at which date the interest rate may be adjusted from time to time.

Annual Payment on Long-Term Debt and Financial and Capital Leases

The annual repayments of long-term debt and capital and financial leases for the years beginning January 1, 2017 and thereafter, are as follows (in millions):

	Long-term Debt	Capital and Financial Lease Obligations	Total
2017	$ —	$ 4	$ 4
2018	—	4	4
2019	—	4	4
2020	—	4	4
2021	—	3	3
Thereafter	1,120	50	1,170
Total	1,120	69	1,189
Unamortized premium, discount and debt issuance cost	(1)	—	(1)
Amounts representing interest	—	(35)	(35)
Total	$ 1,119	$ 34	$ 1,153

The issuance of General and Refunding Mortgage Securities by Sierra Pacific is subject to PUCN approval and is limited by available property and other provisions of the mortgage indentures. As of December 31, 2016, approximately $3.8 billion (based on original cost) of Sierra Pacific's property was subject to the liens of the mortgages.

Financial and Capital Lease Obligations

- Sierra Pacific has master leasing agreements of which various pieces of equipment qualify as capital leases. The remaining equipment is treated as operating leases. Lease terms average seven years under the master lease agreement. Capital assets of $3 million were included in property, plant and equipment, net as of December 31, 2016 and 2015.
- ON Line was placed in-service on December 31, 2013. The Nevada Utilities entered into a long-term transmission use agreement, in which the Nevada Utilities have 25% interest and Great Basin Transmission South, LLC has 75% interest. Refer to Note 4 for additional information. The Nevada Utilities share of the long-term transmission use agreement and ownership interest is split at 5% for Sierra Pacific and 95% for Nevada Power. The term is for 41 years with the agreement ending December 31, 2054. Payments began on January 31, 2014. ON Line assets of $21 million and $22 million were included in property, plant and equipment, net as of December 31, 2016 and 2015, respectively.
- In 2015, Sierra Pacific entered into a 20-year capital lease for the Fort Churchill Solar Array. Capital assets of $10 million and $12 million were included in property, plant and equipment, net as of December 31, 2016 and 2015, respectively.

(8) Fair Value Measurements

The carrying value of Sierra Pacific'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. Sierra Pacific has various financial assets and liabilities that are measured at fair value on the Consolidated Balance Sheets 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 Sierra Pacific 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 Sierra Pacific's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. Sierra Pacific develops these inputs based on the best information available, including its own data.

The following table presents Sierra Pacific'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	Total
As of December 31, 2016:				
Assets:				
Money market mutual funds[1]	$ 35	$ —	$ —	$ 35
Investment funds	1	—	—	1
	$ 36	$ —	$ —	$ 36
As of December 31, 2015:				
Assets - investment funds	$ 1	$ —	$ —	$ 1
Liabilities - commodity derivatives	$ —	$ —	$ (1)	$ (1)

(1) Amounts are included in cash and cash equivalents on the Consolidated Balance Sheets. The fair value of these money market mutual funds approximates cost.

Sierra Pacific's investments in money market mutual funds and equity securities are accounted for as available-for-sale securities and are stated at fair value. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value.

Sierra Pacific's long-term debt is carried at cost on the Consolidated Balance Sheets. The fair value of Sierra Pacific'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 Sierra Pacific'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 Sierra Pacific's long-term debt as of December 31 (in millions):

	2016		2015	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 1,119	$ 1,191	$ 1,165	$ 1,248

(9) Income Taxes

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

	2016	2015	2014
Deferred - Federal	$ 50	$ 48	$ 48
Investment tax credits	(1)	(1)	(1)
Total income tax expense	$ 49	$ 47	$ 47

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

	2016	2015	2014
Federal statutory income tax rate	35%	35%	35%
Effects of ratemaking	1	1	1
Other	1	—	(1)
Effective income tax rate	37%	36%	35%

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

	2016	2015
Deferred income tax assets:		
Federal net operating loss and credit carryforwards	$ 25	$ 39
Employee benefit plans	22	25
Regulatory liabilities	16	19
Capital and financial lease liabilities	12	13
Customer Advances	9	8
Commodity derivative contract	5	5
Other	6	7
Total deferred income tax assets	$ 95	$ 116
Deferred income tax liabilities:		
Property related items	$ (562)	$ (538)
Regulatory assets	(124)	(121)
Capital and financial leases	(12)	(13)
Other	(14)	(14)
Total deferred income tax liabilities	$ (712)	$ (686)
Net deferred income tax liability	$ (617)	$ (570)

The following table provides Sierra Pacific's federal net operating loss and tax credit carryforwards and expiration dates as of December 31, 2016 (in millions):

Net operating loss carryforwards	$ 55
Deferred income taxes on federal net operating loss carryforwards	$ 19
Expiration dates	2031 - 2033
Other tax credits	$ 6
Expiration dates	2021 - 2032

The United States federal jurisdiction is the only significant income tax jurisdiction for NV Energy. In July 2012, the United States Internal Revenue Service and the Joint Committee on Taxation concluded their examination of NV Energy with respect to its United States federal income tax returns for December 31, 2005 through December 31, 2008.

(10) Related Party Transactions

Sierra Pacific provided electricity to Nevada Power of $17 million, $2 million and $8 million for the years ended December 31, 2016, 2015 and 2014, respectively. Receivables associated with these transactions were $12 million and $1 million as of December 31, 2016 and 2015. Sierra Pacific purchased electricity from Nevada Power of $78 million, $69 million and $33 million for the years ended December 31, 2016, 2015 and 2014, respectively. Payables associated with these transactions were $45 million and $15 million as of December 31, 2016 and 2015, respectively.

Sierra Pacific incurs intercompany administrative and shared facility costs with NV Energy and Nevada Power. These transactions are governed by an intercompany service agreement and are priced at cost. NV Energy provided services to Sierra Pacific of $5 million, $6 million and $9 million for the years ending December 31, 2016, 2015 and 2014, respectively. Sierra Pacific provided services to Nevada Power of $14 million, $16 million, and $16 million for the years ended December 31, 2016, 2015 and 2014, respectively. Nevada Power provided services to Sierra Pacific of $24 million, $22 million, and $20 million for the years ended December 31, 2016, 2015 and 2014, respectively. As of December 31, 2016 and 2015, Sierra Pacific's Consolidated Balance Sheets included amounts due to NV Energy of $18 million and $21 million, respectively. There were no receivables due from NV Energy as of December 31, 2016 and 2015. As of December 31, 2016 and 2015, Sierra Pacific's Consolidated Balance Sheets included payables due to Nevada Power of $4 million and $6 million, respectively. There were no receivables due from Nevada Power as of December 31, 2016 and 2015.

Certain disbursements for accounts payable and payroll are made by NV Energy on behalf of Sierra Pacific and reimbursed automatically when settled by the bank. These amounts are recorded as accounts payable at the time of disbursement.

(11) Retirement Plan and Postretirement Benefits

Sierra Pacific is a participant in benefit plans sponsored by NV Energy. The NV Energy Retirement Plan includes a qualified pension plan ("Qualified Pension Plan") and a supplemental executive retirement plan and a restoration plan (collectively, "Non-Qualified Pension Plans") that provide pension benefits for eligible employees. The NV Energy Comprehensive Welfare Benefit and Cafeteria Plan provides certain postretirement health care and life insurance benefits for eligible retirees ("Other Postretirement Plans") on behalf of Sierra Pacific. Sierra Pacific contributed $27 million, $- million and $- million to the Qualified Pension Plan for the year ended December 31, 2016, 2015 and 2014, respectively. For the Other Postretirement Plans, Sierra Pacific contributed $1 million, $- million and $- million for the year ended December 31, 2016, 2015 and 2014, respectively. Sierra Pacific did not make any contributions to the Non-Qualified Pension Plans for the years ended December 31, 2016, 2015 and 2014. Amounts attributable to Sierra Pacific were allocated from NV Energy based upon the current, or in the case of retirees, previous, employment location. Offsetting regulatory assets and liabilities have been recorded related to the amounts not yet recognized as a component of net periodic benefit costs that will be included in regulated rates. Net periodic benefit costs not included in regulated rates are included in accumulated other comprehensive loss, net.

Amounts payable to NV Energy are included on the Consolidated Balance Sheets and consist of the following as of December 31 (in millions):

	2016	2015
Qualified Pension Plan -		
Other long-term liabilities	$ (12)	$ (29)
Non-Qualified Pension Plans:		
Other current liabilities	(1)	(1)
Other long-term liabilities	(9)	(9)
Other Postretirement Plans -		
Other long-term liabilities	(28)	(32)

(12) Asset Retirement Obligations

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

Sierra Pacific does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain generation, transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Consolidated Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled $205 million and $208 million as of December 31, 2016 and 2015, respectively.

The following table presents Sierra Pacific's ARO liabilities by asset type as of December 31 (in millions):

	2016	2015
Asbestos	$ 4	$ 4
Evaporative ponds and dry ash landfills	3	3
Other	3	3
Total asset retirement obligations	$ 10	$ 10

The following table reconciles the beginning and ending balances of Sierra Pacific's ARO liabilities for the years ended December 31 (in millions):

	2016	2015
Beginning balance	$ 10	$ 11
Retirements	—	(1)
Ending balance	$ 10	$ 10
Reflected as:		
Other current liabilities	$ —	$ —
Other long-term liabilities	10	10
	$ 10	$ 10

Certain of Sierra Pacific's decommissioning and reclamation obligations relate to jointly-owned facilities, and as such, Sierra Pacific is committed to pay a proportionate share of the decommissioning or reclamation costs. In the event of a default by any of the other joint participants, the respective subsidiary may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. Sierra Pacific's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities in other long-term liabilities on the Consolidated Balance Sheets.

In December 2014, the United States Environmental Protection Agency ("EPA") 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. The effects of the new rule did not have a material impact on Sierra Pacific's ARO balance.

(13) Commitments and Contingencies

Environmental Laws and Regulations

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

Valmy Generation Station

In June 2009, Sierra Pacific received a request for information from the EPA Region 9 under Section 114 of the Clean Air Act requesting current and historical operations and capital project information for Sierra Pacific's Valmy Generating Station located in Valmy, Nevada. Sierra Pacific co-owns and operates this coal-fueled generating facility. Idaho Power Company owns the remaining 50%. The EPA's Section 114 information request does not allege any incidents of non-compliance at the plant, and there have been no other new enforcement-related proceedings that have been initiated by the EPA relating to the plant. Sierra Pacific completed its responses to the EPA in December 2009 and will continue to monitor developments relating to this Section 114 request. At this time, Sierra Pacific cannot predict the impact, if any, associated with this information request.

Legal Matters

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

Commitments

Sierra Pacific has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2016 are as follows (in millions):

	2017	2018	2019	2020	2021	2022 and Thereafter	Total
Contract type:							
Fuel, capacity and transmission contract commitments	$ 238	$ 156	$ 103	$ 71	$ 62	$ 375	$ 1,005
Fuel and capacity contract commitments (not commercially operable)	5	10	10	11	11	215	262
Operating leases and easements	4	4	3	3	3	46	63
Maintenance, service and other contracts	4	5	4	6	6	17	42
Total commitments	$ 251	$ 175	$ 120	$ 91	$ 82	$ 653	$ 1,372

Fuel and Capacity Contract Commitments

Purchased Power

Sierra Pacific has several contracts for long-term purchase of electric energy which have been approved by the PUCN. The expiration of these contracts range from 2017 to 2039. Purchased power includes contracts which meet the definition of a lease. Sierra Pacific's operating and maintenance expense for purchase power contracts which met the lease criteria for 2016, 2015 and 2014 were $69 million, $65 million and $68 million, respectively, and are recorded as cost of fuel, energy and capacity on the Consolidated Statements of Operations.

Coal and Natural Gas

Sierra Pacific has several long-term contracts for the transport of coal that expire from 2017 to 2018. Additionally, gas transportation contracts expire from 2018 to 2046 and the gas supply contracts expire from 2017 to 2018.

Operating Leases

Sierra Pacific has non-cancelable operating leases primarily for office equipment, office space, certain operating facilities, vehicles and land. These leases generally require Sierra Pacific to pay for insurance, taxes and maintenance applicable to the leased property. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. Sierra Pacific also has non-cancelable easements for land. Operating and maintenance expense on non-cancelable operating leases totaled $6 million, $7 million and $6 million for the year-ended December 31, 2016, 2015 and 2014, respectively.

Maintenance, Service and Other Contracts

Sierra Pacific has long-term service agreements for the performance of maintenance on generation units. Obligation amounts are based on estimated usage. The estimated expiration of these service agreements range from 2017 to 2039.

(14) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2016	2015	2014
Supplemental disclosure of cash flow information -			
Interest paid, net of amounts capitalized	$ 47	$ 54	$ 54
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 15	$ 24	$ 31
Capital and financial lease obligations incurred	$ —	$ 13	$ 1

(15) Segment Information

Sierra Pacific has identified two reportable operating segments: regulated electric and regulated natural gas. The regulated electric segment derives most of its revenue from regulated retail sales of electricity to residential, commercial, and industrial customers and from wholesale sales. The regulated natural gas segment derives most of its revenue from regulated retail sales of natural gas to residential, commercial, and industrial customers and also obtains revenue by transporting natural gas owned by others through its distribution system. Pricing for regulated electric and regulated natural gas sales are established separately by the PUCN; therefore, management also reviews each segment separately to make decisions regarding allocation of resources and in evaluating performance.

Sierra Pacific believes presenting gross margin allows the reader to assess the impact of Sierra Pacific's regulatory treatment and its overall regulatory environment on a consistent basis and is meaningful. Gross margin is calculated as operating revenue less cost of fuel, energy and capacity and natural gas purchased for resale ("cost of sales").

The following tables provide information on a reportable segment basis for the years ended December 31 (in millions):

	Years Ended December 31,		
	2016	2015	2014
Operating revenue:			
Regulated electric	$ 702	$ 810	$ 779
Regulated gas	110	137	125
Total operating revenue	$ 812	$ 947	$ 904
Cost of sales:			
Regulated electric	$ 265	$ 374	$ 361
Regulated gas	55	84	76
Total cost of sales	$ 320	$ 458	$ 437
Gross margin:			
Regulated electric	$ 437	$ 436	$ 418
Regulated gas	55	53	49
Total gross margin	$ 492	$ 489	$ 467
Operating and maintenance:			
Regulated electric	$ 153	$ 149	$ 143
Regulated gas	17	18	19
Total operating and maintenance	$ 170	$ 167	$ 162
Depreciation and amortization:			
Regulated electric	$ 101	$ 96	$ 90
Regulated gas	17	17	15
Total depreciation and amortization	$ 118	$ 113	$ 105
Operating income:			
Regulated electric	$ 161	$ 168	$ 165
Regulated gas	19	16	13
Total operating income	$ 180	$ 184	$ 178
Interest expense:			
Regulated electric	$ 49	$ 56	$ 57
Regulated gas	5	5	4
Total interest expense	$ 54	$ 61	$ 61
Income tax expense:			
Regulated electric	$ 44	$ 43	$ 43
Regulated gas	5	4	4
Total income tax expense	$ 49	$ 47	$ 47

	Years Ended December 31,		
	2016	2015	2014
Capital expenditures:			
Regulated electric	$ 176	$ 229	$ 168
Regulated gas	18	23	18
Total capital expenditures	$ 194	$ 252	$ 186

	As of December 31,		
Total assets:	2016	2015	2014
Regulated electric	$ 3,119	$ 3,060	$ 2,984
Regulated gas	314	316	322
Regulated common assets[1]	60	111	30
Total assets	$ 3,493	$ 3,487	$ 3,336

(1) Consists principally of cash and cash equivalents not included in either the regulated electric or regulated natural gas segments.

(16) Unaudited Quarterly Operating Results (in millions)

	Three-Month Periods Ended			
	March 31, 2016	June 30, 2016	September 30, 2016	December 31, 2016
Regulated electric operating revenue	$ 170	$ 162	$ 207	$ 163
Regulated natural gas operating revenue	47	19	15	29
Operating income	41	28	69	42
Net income	17	10	38	19

	Three-Month Periods Ended			
	March 31, 2015	June 30, 2015	September 30, 2015	December 31, 2015
Regulated electric operating revenue	$ 196	$ 201	$ 228	$ 185
Regulated natural gas operating revenue	50	26	18	43
Operating income	43	37	66	38
Net income	19	16	33	15

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

At the end of the period covered by this Annual Report on Form 10-K, each of Berkshire Hathaway Energy Company, PacifiCorp, MidAmerican Funding, LLC, MidAmerican Energy Company, Nevada Power Company and Sierra Pacific Power Company carried out separate evaluations, under the supervision and with the participation of each such entity's management, including its Chief Executive Officer (principal executive officer) and its Chief Financial Officer (principal financial officer), or persons performing similar functions, of the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15(e) promulgated under the Securities and Exchange Act of 1934, as amended). Based upon these evaluations, management of each such entity, including its Chief Executive Officer (principal executive officer) and its Chief Financial Officer (principal financial officer), or persons performing similar functions, in each case, concluded that the disclosure controls and procedures for such entity were effective to ensure that information required to be disclosed by such entity in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and is accumulated and communicated to its management, including its Chief Executive Officer (principal executive officer) and its Chief Financial Officer (principal financial officer), or persons performing similar functions, in each case, as appropriate to allow timely decisions regarding required disclosure by it. Each such entity hereby states that there has been no change in its internal control over financial reporting during the quarter ended December 31, 2016 that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Management of each of Berkshire Hathaway Energy Company, PacifiCorp, MidAmerican Funding, LLC, MidAmerican Energy Company, Nevada Power Company and Sierra Pacific Power Company, respectively, is responsible for establishing and maintaining, for such entity, adequate internal control over financial reporting, as such term is defined in the Securities Exchange Act of 1934 Rule 13a-15(f). Under the supervision and with the participation of management for each such entity, including its Chief Executive Officer (principal executive officer) and its Chief Financial Officer (principal financial officer), or persons performing similar functions, in each case, such management conducted an evaluation for the relevant entity of the effectiveness of internal control over financial reporting as of December 31, 2016, as required by the Securities Exchange Act of 1934 Rule 13a-15 (c). In making this assessment, management for each such respective entity used the criteria set forth in the framework in "Internal Control - Integrated Framework (2013)" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the evaluation conducted under the framework in "Internal Control - Integrated Framework (2013)," management for each such respective entity concluded that internal control over financial reporting for such entity was effective as of December 31, 2016.

Berkshire Hathaway Energy Company	PacifiCorp	MidAmerican Funding, LLC
February 24, 2017	February 24, 2017	February 24, 2017
MidAmerican Energy Company	Nevada Power Company	Sierra Pacific Power Company
February 24, 2017	February 24, 2017	February 24, 2017

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

BERKSHIRE HATHAWAY ENERGY

BHE is a consolidated subsidiary of Berkshire Hathaway. Each director was elected based on individual responsibilities, experience in the energy industry and functional expertise. BHE's Board of Directors appoints executive officers annually. There are no family relationships among the executive officers, nor, except as set forth in employment agreements, any arrangements or understandings between any executive officer and any other person pursuant to which the executive officer was appointed. Set forth below is certain information, as of February 17, 2017, with respect to the current directors and executive officers of BHE:

GREGORY E. ABEL, 54, Chairman of the Board of Directors since 2011, Chief Executive Officer since 2008, director since 2000, and President since 1998. Mr. Abel joined BHE in 1992 and has extensive executive management experience in the energy industry with strong regulatory and operational skills, including international experience. Mr. Abel also serves as a Director and Vice Chairman of Edison Electric Institute, an association of U.S. investor-owned electric companies, and AEGIS Insurance Services, Inc., a mutual insurance company, and serves on the Board of Directors for PacifiCorp, The Kraft Heinz Company and Nuclear Electric Insurance Limited, a mutual insurance company of nuclear power facilities.

PATRICK J. GOODMAN, 50, Executive Vice President and Chief Financial Officer since 2012. Mr. Goodman was Senior Vice President and Chief Financial Officer from 1999 to 2012. Mr. Goodman joined BHE in 1995. Mr. Goodman is a director of PacifiCorp and a manager of MidAmerican Funding, LLC.

NATALIE L. HOCKEN, 47, Senior Vice President and General Counsel since 2015. Ms. Hocken was Senior Vice President, Transmission and System Operations of PacifiCorp from 2012 to 2015 and Vice President and General Counsel of Pacific Power from 2007 to 2012. Ms. Hocken joined PacifiCorp in 2002. Ms. Hocken is a director of PacifiCorp and a manager of MidAmerican Funding, LLC.

WARREN E. BUFFETT, 86, Director. Mr. Buffett has been a director of BHE since 2000 and has been Chairman of the Board of Directors and Chief Executive Officer of Berkshire Hathaway for more than five years. Mr. Buffett is also a director of The Kraft Heinz Company and Precision Castparts Corp. Mr. Buffett previously served as a director of The Washington Post Company. Mr. Buffett has significant experience as Chairman and Chief Executive Officer of Berkshire Hathaway.

WALTER SCOTT, JR., 85, Director. Mr. Scott has been a director of BHE since 1991. Mr. Scott is also a director of Peter Kiewit Sons' Inc., Berkshire Hathaway and Valmont Industries, Inc. Mr. Scott previously served as Chairman of the Board of Directors of Level 3 Communications, Inc., a successor to certain businesses of Peter Kiewit Sons' Inc., until 2014. Mr. Scott has significant experience and financial expertise as a past chief executive officer and as a director of both public and private corporations and as chairman of a major charitable foundation.

MARC D. HAMBURG, 67, Director. Mr. Hamburg has been a director of BHE since 2000 and has been Chief Financial Officer of Berkshire Hathaway for more than five years. Mr. Hamburg has been Senior Vice President of Berkshire Hathaway since 2008 and was a Vice President of Berkshire Hathaway from 1992 to 2008. Mr. Hamburg was Berkshire Hathaway's Treasurer from 1987 to 2010. Mr. Hamburg is also a director of Precision Castparts Corp. Mr. Hamburg has significant financial experience, including expertise in mergers and acquisitions, accounting, treasury and tax functions.

Board's Role in the Risk Oversight Process

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

Audit Committee and Audit Committee Financial Expert

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

Code of Ethics

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

PACIFICORP

PacifiCorp is an indirect subsidiary of BHE, and its directors consist of executive management from both BHE and PacifiCorp. Each director was elected based on individual responsibilities, experience in the energy industry and functional expertise. There are no family relationships among the executive officers, nor any arrangements or understandings between any executive officer and any other person pursuant to which the executive officer was appointed. Set forth below is certain information, as of February 17, 2017, with respect to the current directors and executive officers of PacifiCorp:

GREGORY E. ABEL, 54, Chairman of the Board of Directors and Chief Executive Officer of PacifiCorp since 2006. Mr. Abel has been BHE's Chairman of the Board of Directors since 2011, Chief Executive Officer since 2008, director since 2000 and President since 1998. Mr. Abel joined BHE in 1992 and has extensive executive management experience in the energy industry with strong regulatory and operational skills, including international experience. Mr. Abel also serves as a Director and Vice Chairman of Edison Electric Institute, an association of U.S. investor-owned electric companies, and AEGIS Insurance Services, Inc., a mutual insurance company, and serves on the Board of Directors for The Kraft Heinz Company and Nuclear Electric Insurance Limited, a mutual insurance company of nuclear power facilities.

STEFAN A. BIRD, 50, President and Chief Executive Officer of Pacific Power and director of PacifiCorp since 2015. Mr. Bird was Senior Vice President, Commercial and Trading, of PacifiCorp Energy from 2007 to 2014. Mr. Bird joined BHE in 1998 and has significant operational, public policy and leadership experience in the energy industry, including expertise in energy supply management, resource acquisition and federal and state regulatory matters.

CINDY A. CRANE, 55, President and Chief Executive Officer of Rocky Mountain Power since 2014 and director of PacifiCorp since 2015. Ms. Crane was Vice President of Interwest Mining Company, a subsidiary of PacifiCorp, from 2009 to 2014. Ms. Crane joined PacifiCorp in 1990 and has significant strategy, operational and leadership experience in the energy industry, including complex commercial negotiations.

PATRICK J. GOODMAN, 50, Director. Mr. Goodman has been a director of PacifiCorp since 2006 and Executive Vice President and Chief Financial Officer of BHE since 2012. Mr. Goodman was Senior Vice President and Chief Financial Officer of BHE from 1999 to 2012. Mr. Goodman joined BHE in 1995 and has significant financial experience, including expertise in mergers and acquisitions, accounting, treasury and tax functions. Mr. Goodman is also a manager of MidAmerican Funding, LLC.

NATALIE L. HOCKEN, 47, Director. Ms. Hocken has been a director of PacifiCorp since 2007 and Senior Vice President and General Counsel of BHE since 2015. Ms. Hocken was Senior Vice President, Transmission and System Operations of PacifiCorp from 2012 to 2015 and Vice President and General Counsel of Pacific Power from 2007 to 2012. Ms. Hocken joined PacifiCorp in 2002 and has significant experience in the utility industry, including expertise in transmission, legal matters and federal and state regulatory matters. Ms. Hocken is also a manager of MidAmerican Funding, LLC.

NIKKI L. KOBLIHA, 44, Director. Ms. Kobliha has been a director since 2017, Vice President and Chief Financial Officer of PacifiCorp since 2015 and Treasurer since 2017. Ms. Kobliha joined PacifiCorp in 1997 and has held various finance positions within PacifiCorp.

Board's Role in the Risk Oversight Process

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

Audit Committee and Audit Committee Financial Expert

During the year ended December 31, 2016, and as of the date of this Annual Report on Form 10-K, PacifiCorp's Board of Directors did not have an audit committee. PacifiCorp is not required to have an audit committee as its common stock is indirectly and wholly owned by BHE. However, the audit committee of BHE acts as the audit committee for PacifiCorp.

Code of Ethics

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

MIDAMERICAN FUNDING, MIDAMERICAN ENERGY, NEVADA POWER AND SIERRA PACIFIC

Information required by Item 10 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

Item 11. Executive Compensation

BERKSHIRE HATHAWAY ENERGY

Compensation Discussion and Analysis

Compensation Philosophy and Overall Objectives

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

How is Compensation Determined

BHE's Compensation Committee is comprised of Messrs. Warren E. Buffett and Walter Scott, Jr. The Compensation Committee is responsible for the establishment and oversight of BHE's compensation policy. Approval of compensation decisions for BHE's NEOs is made by the Compensation Committee, unless specifically delegated. Although the Compensation Committee reviews each NEO's complete compensation package at least annually, it has delegated to the Chairman and CEO authority to approve off-cycle pay changes, performance awards and participation in other employee benefit plans and programs for the other NEOs.

BHE's criteria for assessing executive performance and determining compensation in any year is inherently subjective and is not based upon specific formulas or weighting of factors. BHE does not specifically use other companies as benchmarks when establishing its NEOs' compensation. However, the Compensation Committee reviews peer company data when making annual base salary and incentive recommendations for the Chairman and CEO. The peer companies for 2016 were American Electric Power Company, Inc., Consolidated Edison, Inc., Dominion Resources, Inc., Duke Energy Corporation, Edison International, Entergy Corporation, Exelon Corporation, FirstEnergy Corp., NextEra Energy, Inc., PG&E Corporation, PPL Corporation, Public Service Enterprise Group Incorporated, Sempra Energy, The Southern Company and Xcel Energy Inc.

BHE engages the compensation practice of Willis Towers Watson PLC, or Willis Towers Watson, to research and document the peer company data to be reviewed by the Compensation Committee when making annual base salary and incentive recommendations for the Chairman and CEO. The fee paid to Willis Towers Watson for this service was $4,434 in 2016. BHE also engages Willis Towers Watson to provide other services unrelated to executive compensation, including actuarial, administration and consulting services related to BHE's retirement plans. These services are approved by senior management and the aggregate fees paid to Willis Towers Watson for these services were $2,705,875 in 2016. BHE's Board of Directors is not involved in the selection or approval of Willis Towers Watson for these services.

Discussion and Analysis of Specific Compensation Elements

Base Salary

BHE determines base salaries for all of its NEOs by reviewing its overall performance and each NEO's performance, the value each NEO brings to BHE and general labor market conditions. While base salary provides a base level of compensation intended to be competitive with the external market, the annual base salary adjustment for each NEO is determined on a subjective basis after consideration of these factors and is not based on target percentiles or other formal criteria.

The Chairman and CEO makes recommendations regarding the other NEOs' base salaries, and the Compensation Committee sets the Chairman and CEO's base salary. All merit increases are approved by the Compensation Committee and take effect on January 1 of each year. An increase or decrease in base salary may also result from a promotion or other significant change in a NEO's responsibilities during the year. Base salaries for all NEOs increased on average by 1.56% effective January 1, 2016. There were no base salary changes for BHE's NEOs during the year after the January 1, 2016 merit increase.

Short-Term Incentive Compensation

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

Performance Incentive Plan

Under BHE's Performance Incentive Plan, or PIP, all NEOs are eligible to earn an annual discretionary cash incentive award, which is determined on a subjective basis and is not based on a specific formula or cap. A variety of factors are considered in determining each NEO's annual incentive award including the NEO's performance, BHE's overall performance and each NEO's contribution to that overall performance. An individual NEO's performance is evaluated using financial and non-financial principles, including customer service; operational excellence; financial strength; employee commitment and safety; environmental respect; and regulatory integrity, as well as the NEO's response to issues and opportunities that arise during the year. No factor was individually material to the determination of the amounts paid to each NEO under the PIP for 2016. The Chairman and CEO recommends annual incentive awards for the other NEOs to the Compensation Committee prior to the last committee meeting of each year, held in the fourth quarter. The Compensation Committee determines the Chairman and CEO's award, which is based on BHE's overall performance and direction and is not based on the performance of any specific subsidiary. If approved by the Compensation Committee, awards are paid prior to year-end.

Performance Awards

In addition to the annual awards under the PIP, BHE may grant cash performance awards periodically during the year to one or more NEOs to reward the accomplishment of significant non-recurring tasks or projects. These awards are discretionary and are approved by the Chairman and CEO, as delegated by the Compensation Committee. In December 2016, an award was granted to Mr. Goodman and Ms. Hocken in recognition of their outstanding efforts. Although Mr. Abel is eligible for performance awards, he has not been granted an award in the past five years.

Long-Term Incentive Compensation

The objective of long-term incentive compensation is to retain NEOs, reward their exceptional performance and motivate them to create long-term, sustainable value. BHE's current long-term incentive compensation program is cash-based. BHE has not issued stock options or other forms of equity-based awards since March 2000.

Long-Term Incentive Partnership Plan

The Berkshire Hathaway Energy Company Long-Term Incentive Partnership Plan, or LTIP, is designed to retain key employees and to align BHE's interests and the interests of the participating employees. Mr. Goodman and Ms. Hocken participate in this plan, while BHE's Chairman and CEO does not. BHE's LTIP provides for annual discretionary awards based upon significant accomplishments by the individual participants and the achievement of the financial and non-financial objectives previously described. The goals are developed with the objective of being attainable with a sustained, focused and concerted effort and are determined and communicated by January of each plan year. The Chairman and CEO approves eligibility to participate in the plan and the amount of the incentive award. Awards are capped at 1.0 times base salary and finalized in the first quarter of the following year. The Chairman and CEO may grant a supplemental award to any participant for the award year separate from the incentive award subject to the same terms and conditions as the incentive award. These cash-based awards are subject to mandatory deferral and equal annual vesting over a four-year period starting in the performance year. Participants allocate the value of their deferral accounts among various investment alternatives. Gains or losses may be incurred based on investment performance. Participating NEOs may elect to defer all or a part of the award or receive payment in cash after the four-year mandatory deferral and vesting period. Vested balances (including any investment gains or losses thereon) of terminating participants are paid at the time of termination.

Other Employee Benefits

Supplemental Executive Retirement Plan

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

Deferred Compensation Plan

The Berkshire Hathaway Energy Company Executive Voluntary Deferred Compensation Plan, or the DCP, provides a means for all NEOs to make voluntary deferrals of up to 50% of base salary and 100% of short-term incentive compensation awards. BHE includes the DCP as part of the participating NEO's overall compensation in order to provide a comprehensive, competitive package. The deferrals and any investment returns grow on a tax-deferred basis. Amounts deferred under the DCP receive a rate of return based on the returns of any combination of various investment options offered under the DCP and selected by the participant. The plan allows participants to choose from three forms of distribution. The plan permits BHE to make discretionary contributions on behalf of participants; however, BHE has not made contributions to date.

Financial Planning and Tax Preparation

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

Executive Life Insurance

BHE provides universal life insurance to Messrs. Abel and Goodman having a death benefit of two times annual base salary during employment less $50,000, reducing to one times annual base salary in retirement. The value of the benefit is included in the NEO's taxable income. BHE includes the executive life insurance as part of the participating NEO's overall compensation in order to provide a comprehensive, competitive package.

Potential Payments Upon Termination

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

Compensation Committee Report

The Compensation Committee, consisting of Messrs. Buffett and Scott, has reviewed and discussed the Compensation Discussion and Analysis with management and, based on this review and discussion, has recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

Warren E. Buffett
Walter Scott, Jr.

Summary Compensation Table

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

Name and Principal Position	Year	Base Salary	Bonus[1]	Non-Equity Incentive Plan Compensation	Change in Pension Value and Nonqualified Deferred Compensation Earnings[2]	All Other Compensation[3]	Total[4]
Gregory E. Abel, Chairman, President	2016	$ 1,000,000	$ 15,000,000	$ —	$ 1,377,000	$ 141,227	17,518,227
and Chief Executive Officer	2015	1,000,000	11,500,000	28,000,000	—	267,944	40,767,944
	2014	1,000,000	11,500,000	12,000,000	2,625,000	450,612	27,575,612
Patrick J. Goodman, Executive Vice	2016	470,000	2,076,308	—	756,000	47,035	3,349,343
President and Chief Financial	2015	460,000	1,672,101	—	—	57,451	2,189,552
Officer	2014	450,000	1,717,600	—	1,146,000	46,413	3,360,013
Natalie L. Hocken, Senior Vice	2016	410,000	1,286,748	—	7,000	30,498	1,734,246
President and General Counsel[5]	2015	313,636	810,090	—	—	30,339	1,154,065

(1) Consists of annual cash incentive awards earned pursuant to the PIP for BHE's NEOs, performance awards earned related to non-routine projects, and the vesting of LTIP awards and associated vested earnings. The breakout for 2016 is as follows:

	PIP	Performance Award	LTIP Vested Awards	LTIP Vested Earnings	Total
Gregory E. Abel	$ 15,000,000	$ —	$ —	$ —	$ —
Patrick J. Goodman	500,000	430,000	945,000	201,308	1,146,308
Natalie L. Hocken	375,000	215,000	450,747	246,001	696,748

The ultimate payouts of LTIP awards are undeterminable as the amounts to be paid out may increase or decrease depending on investment performance. Net income, the net income target goal and the matrix below were used in determining the gross amount of the LTIP award available to the participants. Net income for determining the award and the award itself are subject to discretionary adjustment by the Chairman and CEO and Compensation Committee. In 2016, the gross award was determined based on the overall achievement of BHE's financial and non-financial objectives.

Net Income	Award
Less than or equal to net income target goal	None
Exceeds net income target goal	33.33% of excess

(2) Amounts are based upon the aggregate increase in the actuarial present value of all qualified and nonqualified defined benefit plans, which include BHE's cash balance and SERP, as applicable. Amounts are computed using assumptions consistent with those used in preparing the related pension disclosures in the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and are as of December 31, 2016. No participant in BHE's DCP earned "above-market" or "preferential" earnings on amounts deferred.

(3) Amounts consist of 401(k) contributions BHE paid on behalf of the NEOs, as well as perquisites and other personal benefits related to life insurance premiums, the personal use of corporate aircraft and financial planning and tax preparation that BHE paid on behalf of Messrs. Abel and Goodman. The personal use of corporate aircraft represents BHE's incremental cost of providing this personal benefit determined by applying the percentage of flight hours used for personal use to BHE's incremental expenses incurred from operating its corporate aircraft, partially offset by reimbursed costs by the NEO. All other compensation is based upon amounts paid by BHE.

Items required to be reported and quantified are as follows: Mr. Abel - personal use of corporate aircraft of $73,764, life insurance premiums paid of $44,490 and 401(k) contributions of $12,773; Mr. Goodman - 401(k) contributions of $29,998; and Ms. Hocken - 401(k) contributions of $29,998.

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

(5) Ms. Hocken was named Senior Vice President and General Counsel effective July 10, 2015. Ms. Hocken was previously the Senior Vice President, Transmission and System Operations at PacifiCorp, an indirect, wholly owned subsidiary of BHE's.

Pension Benefits

The following table sets forth certain information regarding the defined benefit pension plan accounts held by each of BHE's NEOs as of December 31, 2016:

Name	Plan name	Number of years credited service(1)	Present value of accumulated benefit(2)	Payments during last fiscal year
Gregory E. Abel	SERP	n/a	$ 11,648,000	$ —
	MidAmerican Energy Company Retirement Plan	18 years	326,000	—
Patrick J. Goodman	SERP	22 years	4,055,000	—
	MidAmerican Energy Company Retirement Plan	10 years	195,000	—
Natalie L. Hocken	PacifiCorp Retirement Plan	7 years	102,000	—

(1) Mr. Goodman's credited years of service, for purposes of the SERP only, includes 18 years of service with BHE and four additional years of imputed service from a predecessor company.

(2) Amounts are computed using assumptions consistent with those used in preparing the related pension disclosures in Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and are as of December 31, 2016, which is the measurement date for the plans. The present value of accumulated benefits for the SERP was calculated using the following form of payment assumptions: (1) Mr. Abel - a 100% joint and survivor annuity and (2) Mr. Goodman - a 66 2/3% joint and survivor annuity. The present value of accumulated benefits for the MidAmerican Energy Company Retirement Plan was calculated using a 90% lump sum payment and a 10% single life annuity. The present value assumptions used in calculating the present value of accumulated benefits for both the SERP and the MidAmerican Energy Company Retirement Plan were as follows: a cash balance interest crediting rate of 1.44% in 2017 and 2018 and 2.10% thereafter; a cash balance conversion rate of 4.10% in 2016 and thereafter; a discount rate of 4.10%; an expected retirement age of 65; and postretirement mortality and cash balance conversion mortality based on the RP-2014 mortality tables, translated to 2011 using scale MP-2014 and loaded 3% for credibility-weighted experience, with custom RPEC-2016 generational improvements.

The present value of accumulated benefits for the PacifiCorp Retirement Plan was calculated using the following assumptions: 50% lump sum payment, 35% joint and 100% survivor annuity and 15% single life annuity; a discount rate of 4.05%; an expected retirement age of 65; postretirement mortality and lump sum conversion mortality based on the RP-2014 mortality tables, translated to 2011 using scale MP-2014 and loaded 3% for credibility-weighted experience, with custom RPEC-2014 generational improvements.

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

Under the MidAmerican Energy Company Retirement Plan, each NEO (except Ms. Hocken, who participated in the PacifiCorp Retirement Plan through December 31, 2015) has an account, for record-keeping purposes only, to which credits are allocated annually based upon a percentage of the NEO's base salary and incentive paid in the plan year. In addition, all balances in the accounts of NEOs earn a fixed rate of interest that is credited annually. The interest rate for a particular year is based on the one-year constant maturity Treasury yield plus seven-tenths of one percentage point. Each NEO is vested in the MidAmerican Energy Company Retirement Plan. At retirement, or other termination of employment, an amount equal to the vested balance then credited to the account is payable to the NEO in the form of a lump sum or an annuity.

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

Nonqualified Deferred Compensation

The following table sets forth certain information regarding the nonqualified deferred compensation plan accounts held by each of BHE's NEOs as of December 31, 2016:

Name	Executive contributions in 2016[1]	Registrant contributions in 2016	Aggregate earnings in 2016	Aggregate withdrawals/ distributions	Aggregate balance as of December 31, 2016
Gregory E. Abel	$ —	$ —	$ 197,944	$ (374,059)	$ 2,061,061
Patrick J. Goodman	—	—	142,535	—	1,624,365
Natalie L. Hocken	—	—	115,240	(71,828)	1,379,287

(1) Excludes the value of 10,041 shares of BHE common stock reserved for issuance to Mr. Abel. Mr. Abel deferred the right to receive the value of these shares pursuant to a legacy nonqualified deferred compensation plan.

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

The DCP allows participants to maintain three accounts based upon when they want to receive payments: retirement account, in-service account and education account. Both the retirement and in-service accounts can be distributed as lump sums or in up to 10 annual installments. The education account is distributed in four annual installments. If a participant leaves employment prior to retirement (age 55) all amounts in the participant's account will be paid out in a lump sum as soon as administratively practicable. Participants are 100% vested in their deferrals and any investment gains or losses recorded in their accounts.

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

Potential Payments Upon Termination

BHE has entered into employment agreements with Messrs. Abel and Goodman that provide for payments following termination of employment under various circumstances, which do not include change-in-control provisions. A termination of employment of either Messrs. Abel or Goodman will occur upon their respective resignation (with or without good reason), permanent disability, death, or termination by BHE with or without cause. The employment agreement for Mr. Abel also includes provisions specific to the calculation of his SERP benefit.

Ms. Hocken does not have an employment agreement. Where a NEO does not have an employment agreement, or in the event that the agreements for Messrs. Abel and Goodman do not address an issue, payments upon termination are determined by the applicable plan documents and BHE's general employment policies and practices as discussed below. The following discussion provides further detail on post-termination payments.

Gregory E. Abel

Mr. Abel's employment agreement entitles him to receive two years base salary continuation and payments in respect of average bonuses for the prior two years in the event BHE terminates his employment other than for cause. The payments are to be paid as a lump sum with no discount for present valuation.

In addition, if Mr. Abel's employment is terminated due to death, permanent disability or other than for cause, he is entitled to continuation of his senior executive employee benefits (or the economic equivalent thereof) for two years. If Mr. Abel resigns, BHE must pay him any accrued but unpaid base salary, unless he resigns for good reason, in which case he will receive the same benefits as if he were terminated other than for cause.

Payments made in accordance with the employment agreement are contingent on Mr. Abel complying with the confidentiality and post-employment restrictions described therein. The term of the agreement effectively expires on August 6, 2021, and is extended automatically for additional one year terms thereafter subject to Mr. Abel's election to decline renewal at least 365 days prior to the August 6 that is four years prior to the current expiration date (or by August 6, 2017, for the agreement not to extend to August 6, 2022).

The following table sets forth the estimated enhancements to payments pursuant to the termination scenarios indicated. Payments or benefits that are not enhanced in form or amount upon the occurrence of a particular termination scenario, including 401(k) and nonqualified deferred compensation account balances and those portions of life insurance benefits and cash balance pension amounts that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2016, and are payable as lump sums unless otherwise noted.

Termination Scenario	Cash Severance(1)	Incentive	Life Insurance(2)	Pension(3)	Benefits Continuation(4)	Excise and Other Taxes(5)
Retirement, Voluntary and Involuntary With Cause	$ —	$ —	$ —	$ 8,452,000	$ —	$ —
Involuntary Without Cause, Disability and Voluntary With Good Reason	28,500,000	—	—	8,452,000	85,491	—
Death	28,500,000	—	1,825,824	7,733,000	85,491	—

(1) The cash severance payments are determined in accordance with Mr. Abel's employment agreement.

(2) Life insurance benefits are equal to two times base salary, as of the preceding June 1, less the benefits otherwise payable in all other termination scenarios, which are equal to the total cash value of the policies less cumulative premiums paid by BHE.

(3) Pension values represent the excess of the present value of benefits payable under each termination scenario over the amount already reflected in the Pension Benefits Table. Mr. Abel's death scenario is based on a 100% joint and survivor with 15-year certain annuity commencing immediately. Mr. Abel's other termination scenarios are based on a 100% joint and survivor annuity commencing immediately.

(4) Includes health and welfare, life insurance and financial planning and tax preparation benefits for two years. The health and welfare benefit amounts are estimated using the rates BHE currently charges employees terminating employment but electing to continue their medical, dental and vision insurance after termination. These amounts are grossed-up for taxes and then reduced by the amount Mr. Abel would have paid if he had continued his employment. The life insurance benefit amounts are based on the cost of individual policies offering benefits equivalent to BHE's group coverage and are grossed-up for taxes. These amounts also assume benefit continuation for the entire two year period, with no offset by another employer. BHE will also continue to provide financial planning and tax preparation reimbursement, or the economic equivalent thereof, for two years or pay a lump sum cash amount to keep Mr. Abel in the same economic position on an after-tax basis. The amount included is based on an annual estimated cost using the most recent three-year average annual reimbursement. If it is determined that benefits paid with respect to the extension of medical and dental benefits to Mr. Abel would not be exempt from taxation under the Internal Revenue Code, BHE shall pay to Mr. Abel a lump sum cash payment following separation from service to allow him to obtain equivalent medical and dental benefits and which would put him in the same after-tax economic position.

(5) As provided in Mr. Abel's employment agreement, should it be deemed under Section 280G of the Internal Revenue Code that termination payments constitute excess parachute payments subject to an excise tax, BHE will gross up such payments to cover the excise tax and any additional taxes associated with such gross-up. Based on computations prescribed under Section 280G and related regulations, BHE does not believe that any of the termination scenarios are subject to any excise tax.

Patrick J. Goodman

Mr. Goodman's employment agreement entitles him to receive two years base salary continuation and payments in respect of average bonuses for the prior two years in the event BHE terminates his employment other than for cause. The payments are to be paid as a lump sum with no discount for present valuation.

In addition, if Mr. Goodman's employment is terminated due to death, permanent disability or other than for cause, he is entitled to continuation of his senior executive employee benefits (or the economic equivalent thereof) for one year. If Mr. Goodman resigns, BHE must pay him any accrued but unpaid base salary, unless he resigns for good reason, in which case he will receive the same benefits as if he were terminated other than for cause.

Payments made in accordance with the employment agreement are contingent on Mr. Goodman complying with the confidentiality and post-employment restrictions described therein. The term of the agreement expires on April 21, 2018, but is extended automatically for additional one year terms thereafter subject to Mr. Goodman's election to decline renewal at least 365 days prior to the then current expiration date or termination.

The following table sets forth the estimated enhancements to payments pursuant to the termination scenarios indicated. Payments or benefits that are not enhanced in form or amount upon the occurrence of a particular termination scenario, including 401(k) and nonqualified deferred compensation account balances and those portions of long-term incentive payments, life insurance benefits and cash balance pension amounts that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2016, and are payable as lump sums unless otherwise noted.

Termination Scenario	Cash Severance(1)	Incentive(2)	Life Insurance(3)	Pension(4)	Benefits Continuation(5)	Excise and Other Taxes(6)
Retirement and Voluntary	$ —	$ —	$ —	$ 2,077,000	$ —	$ —
Involuntary With Cause	—	—	—	—	—	—
Involuntary Without Cause and Voluntary With Good Reason	4,360,000	—	—	2,077,000	24,239	—
Death	4,360,000	1,747,885	892,388	2,892,000	24,239	—
Disability	4,360,000	1,747,885	—	3,534,000	24,239	—

(1) The cash severance payments are determined in accordance with Mr. Goodman's employment agreement.

(2) Amounts represent the unvested portion of Mr. Goodman's LTIP account, which becomes 100% vested upon his death or disability.

(3) Life insurance benefits are equal to two times base salary, as of the preceding June 1, less the benefits otherwise payable in all other termination scenarios, which are equal to the total cash value of the policies less cumulative premiums paid by BHE.

(4) Pension values represent the excess of the present value of benefits payable under each termination scenario over the amount already reflected in the Pension Benefits Table. Mr. Goodman's voluntary termination, retirement, involuntary without cause, and change in control termination scenarios are based on a 66 2/3% joint and survivor annuity commencing at age 55 (reductions for termination prior to age 55 and commencement prior to age 65). Mr. Goodman's disability scenario is based on a 66 2/3% joint and survivor annuity commencing at age 55 (no reduction for termination prior to age 55, reduced for commencement prior to age 65). Mr. Goodman's death scenario is based on a 15-year certain only annuity commencing immediately (no reduction for termination prior to age 55 and commencement prior to age 65).

(5) Includes health and welfare, life insurance and financial planning and tax preparation benefits for one year. The health and welfare benefit amounts are estimated using the rates BHE currently charges employees terminating employment but electing to continue their medical, dental and vision insurance after termination. These amounts are grossed-up for taxes and then reduced by the amount Mr. Goodman would have paid if he had continued his employment. The life insurance benefit amounts are based on the cost of individual policies offering benefits equivalent to BHE's group coverage and are grossed-up for taxes. These amounts also assume benefit continuation for the entire one year period, with no offset by another employer. BHE will also continue to provide financial planning and tax preparation reimbursement, or the economic equivalent thereof, for one year or pay a lump sum cash amount to keep Mr. Goodman in the same economic position on an after-tax basis. The amount included is based on an annual estimated cost using the most recent three-year average annual reimbursement.

(6) As provided in Mr. Goodman's employment agreement, should it be deemed under Section 280G of the Internal Revenue Code that termination payments constitute excess parachute payments subject to an excise tax, BHE will gross up such payments to cover the excise tax and any additional taxes associated with such gross-up. Based on computations prescribed under Section 280G and related regulations, BHE does not believe that any of the termination scenarios are subject to any excise tax.

Natalie L. Hocken

The following table sets forth the estimated enhancements to payments pursuant to the termination scenarios indicated. Payments or benefits that are not enhanced in form or amount upon the occurrence of a particular termination scenario, including 401(k) and nonqualified deferred compensation account balances and those portions of long-term incentive payments and cash balance pension amounts that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2016, and are payable as lump sums unless otherwise noted.

Termination Scenario	Cash Severance	Incentive(1)	Life Insurance	Pension(2)	Benefits Continuation	Excise and Other Taxes
Retirement, Voluntary and Involuntary With or Without Cause	$ —	$ —	$ —	$ 6,000	$ —	$ —
Death and Disability	—	1,055,675	—	6,000	—	—

(1) Amounts represent the unvested portion of Ms. Hocken's LTIP account, which becomes 100% vested upon her death or disability.

(2) Pension values represent the excess of the present value of benefits payable under each termination scenario over the amount already reflected in the Pension Benefits Table.

Director Compensation

BHE's directors are not paid any fees for serving as directors. All directors are reimbursed for their expenses incurred in attending Board of Directors meetings.

Compensation Committee Interlocks and Insider Participation

Mr. Buffett is the Chairman of the Board of Directors and Chief Executive Officer of Berkshire Hathaway, BHE's majority owner. Mr. Scott is a former officer of BHE. Based on the standards of the New York Stock Exchange LLC, on which the common stock of BHE's majority owner, Berkshire Hathaway, is listed, BHE's Board of Directors has determined that Messrs. Buffett and Scott are not independent because of their ownership of BHE common stock. None of BHE's executive officers serves as a member of the compensation committee of any company that has an executive officer serving as a member of BHE's Board of Directors. None of BHE's executive officers serves as a member of the board of directors of any company that has an executive officer serving as a member of BHE's Compensation Committee. See also Berkshire Hathaway Energy's Item 13 in this Annual Report on Form 10-K.

PACIFICORP

Compensation Discussion and Analysis

Compensation Philosophy and Overall Objectives

Mr. Gregory E. Abel, PacifiCorp's Chairman of the Board of Directors and Chief Executive Officer, or Chairman and CEO, receives no direct compensation from PacifiCorp. PacifiCorp reimburses its indirect parent company, BHE, for the cost of Mr. Abel's time spent on matters supporting PacifiCorp, including compensation paid to him by BHE, pursuant to an intercompany administrative services agreement among BHE and its subsidiaries. Please refer to Berkshire Hathaway Energy's Item 11 in this Annual Report on Form 10-K for executive compensation and post-termination payment information for Mr. Abel.

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

How is Compensation Determined

PacifiCorp's compensation committee consists solely of Mr. Abel. Mr. Abel also serves as BHE's Chairman, President and Chief Executive Officer. Mr. Abel is responsible for the establishment and oversight of PacifiCorp's compensation policy and for approving compensation decisions for its NEOs such as approving base pay increases, incentive and performance awards, off-cycle pay changes, and participation in other employee benefit plans and programs.

PacifiCorp's criteria for assessing executive performance and determining compensation in any year is inherently subjective and is not based upon specific formulas or weighting of factors. PacifiCorp does not specifically use other companies as benchmarks when establishing its NEOs' compensation.

Discussion and Analysis of Specific Compensation Elements

Base Salary

PacifiCorp determines base salaries for all of its NEOs, other than Mr. Abel, by reviewing its overall performance, and each NEO's performance, the value each NEO brings to PacifiCorp and general labor market conditions. While base salary provides a base level of compensation intended to be competitive with the external market, the annual base salary adjustment for each NEO, other than Mr. Abel, is determined on a subjective basis after consideration of these factors and is not based on target percentiles or other formal criteria. All merit increases are approved by Mr. Abel and take effect in the last payroll period of each year. An increase or decrease in base salary may also result from a promotion or other significant change in a NEO's responsibilities during the year. For 2016, base salaries for all NEOs, other than Mr. Abel, increased on average by 2.3% effective December 26, 2015, reflecting merit increases.

Short-Term Incentive Compensation

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

Annual Incentive Plan

Under PacifiCorp's Annual Incentive Plan, or AIP, all NEOs, other than Mr. Abel, are eligible to earn an annual discretionary cash incentive award, which is determined on a subjective basis at Mr. Abel's sole discretion and is not based on a specific formula or cap. Mr. Abel considers a variety of factors in determining each NEO's annual incentive award including the NEO's performance, PacifiCorp's overall performance and each NEO's contribution to that overall performance. Mr. Abel evaluates performance using financial and non-financial objectives, including customer service, employee commitment and safety, environmental respect, regulatory integrity, operational excellence and financial strength, as well as the NEO's response to issues and opportunities that arise during the year. No factor was individually material to Mr. Abel's determination regarding the amounts paid to each NEO under the AIP for 2016. Approved awards are paid prior to year-end.

Performance Awards

In addition to the annual awards under the AIP, PacifiCorp may grant cash performance awards periodically during the year to one or more NEOs, other than Mr. Abel, to reward the accomplishment of significant non-recurring tasks or projects. These awards are discretionary and are approved by Mr. Abel. In December 2016, a cash performance award was granted to Messrs. Bird and Reiten and Ms. Crane in recognition of their outstanding efforts.

Long-Term Incentive Compensation

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

Long-Term Incentive Partnership Plan

The PacifiCorp Long-Term Incentive Partnership Plan, or LTIP, is designed to retain key employees and to align PacifiCorp's interests and the interests of the participating employees. All of PacifiCorp's NEOs, other than Mr. Abel, participate in the LTIP. The LTIP provides for annual discretionary awards based upon significant accomplishments by the individual participants and the achievement of the financial and non-financial objectives previously described. The goals are developed with the objective of being attainable with a sustained, focused and concerted effort and are determined and communicated by January of each plan year. The BHE Chairman and PacifiCorp's Presidents approve eligibility to participate in the LTIP and the amount of the incentive award. Awards are capped at 1.0 times base salary and finalized in the first quarter of the following year. The BHE Chairman and PacifiCorp's Presidents may grant a supplemental award to any participant for the award year separate from the incentive award, subject to the same terms and conditions as the incentive award. PacifiCorp's Presidents may participate in the LTIP but only the BHE Chairman shall make determinations regarding their participation and the value of their incentive award. These cash-based awards are subject to mandatory deferral and equal annual vesting over a four-year period starting in the performance year. Participants allocate the value of their deferral accounts among various investment alternatives. Gains or losses may be incurred based on investment performance. Participating NEOs may elect to defer all or a part of the award or receive payment in cash after the four-year mandatory deferral and vesting period. Vested balances (including any investment gains or losses thereon) of terminating participants are paid at the time of termination.

Deferred Compensation Plan

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

Potential Payments Upon Termination

PacifiCorp's NEOs, other than Mr. Abel, are not entitled to severance or enhanced benefits upon termination of employment or change in control. However, upon any termination of employment, PacifiCorp's other NEOs would be entitled to the vested balances in the LTIP, DCP and PacifiCorp's non-contributory defined benefit pension plan, or the Retirement Plan.

Compensation Committee Report

Mr. Abel, PacifiCorp's Chairman and CEO and sole member of PacifiCorp's compensation committee, has reviewed the Compensation Discussion and Analysis and, based on this review, has recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

Gregory E. Abel

Summary Compensation Table

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

Name and Principal Position	Year	Base Salary	Bonus [(1)]	Change in Pension Value and Nonqualified Deferred Compensation Earnings [(2)]	All Other Compensation [(3)]	Total [(4)]
Gregory E. Abel [(5)]	2016	$ —	$ —	$ —	$ —	$ —
Chairman and	2015	—	—	—	—	—
Chief Executive Officer	2014	—	—	—	—	—
Stefan A. Bird	2016	338,000	738,784	629	13,958	1,091,371
President and Chief Executive	2015	313,275	844,634	13,201	12,614	1,183,724
Officer, Pacific Power	2014	—	—	—	—	—
Cindy A. Crane	2016	338,000	758,248	35,752	15,841	1,147,841
President and Chief Executive	2015	324,028	758,656	8,589	13,429	1,104,702
Officer, Rocky Mountain Power	2014	224,538	580,950	79,542	73,838	958,868
R. Patrick Reiten	2016	344,007	1,058,240	—	26,809	1,429,056
President and Chief Executive	2015	330,000	898,935	—	25,864	1,254,799
Officer, PacifiCorp Transmission	2014	320,000	1,167,125	822	25,980	1,513,927
Nikki L. Kobliha	2016	203,900	143,004	9,728	29,585	386,217
Vice President, Chief Financial Officer, and Treasurer	2015	177,384	91,758	—	27,253	296,395
	2014	—	—	—	—	—

(1) Consists of annual cash incentive awards earned pursuant to the AIP for PacifiCorp's NEOs, performance awards for Messrs. Bird, Reiten and Crane in recognition of efforts to support PacifiCorp's objectives and the vesting of LTIP awards and associated vested earnings. The breakout for 2016 is as follows:

			LTIP		
	AIP	Performance Award	Vested Awards	Vested Earnings	Total
Stefan A. Bird	$ 304,000	$ 34,000	$ 378,722	$ 22,062	$ 400,784
Cindy A. Crane	304,000	34,000	318,484	101,764	420,248
R. Patrick Reiten	304,000	16,000	477,500	260,739	738,239
Nikki L. Kobliha	121,100	—	21,750	154	21,904

The ultimate payouts of LTIP awards are undeterminable as the amounts to be paid out may increase or decrease depending on investment performance. BHE's Chairman and PacifiCorp's Presidents establish the award categories for determining LTIP awards based on net income target goals or other criteria. In 2016, the gross award was subjectively determined at the discretion of the BHE Chairman and PacifiCorp Presidents based on the overall achievement of PacifiCorp's financial and non-financial objectives including customer service, employee commitment and safety, environmental respect, regulatory integrity, operational excellence and financial strength.

(2) Amounts are based upon the aggregate increase in the actuarial present value of all qualified and nonqualified defined benefit plans, which includes the Retirement Plan. Refer to the Pension Benefits table below for a discussion of the assumptions used in calculating these amounts. No participant in PacifiCorp's nonqualified deferred compensation plans earned "above market" or "preferential" earnings on amounts deferred. Negative amounts for the change in pension value not reported in the Summary Compensation Table are as follows: Mr. Reiten $(651).

(3) Amounts consist of PacifiCorp K Plus Employee Savings Plan, or 401(k) Plan, contributions PacifiCorp paid on behalf of the NEOs, except for Mr. Bird and Ms. Crane for whom PacifiCorp also includes an amount paid to her as a tax gross-up with respect to a personal benefit with a value less than $10,000.

(4) Any amounts voluntarily deferred by the NEO, if applicable, are included in the appropriate column in the Summary Compensation Table.

(5) Mr. Abel receives no direct compensation from PacifiCorp. PacifiCorp reimburses BHE for the cost of Mr. Abel's time spent on matters supporting PacifiCorp, including compensation paid to him by BHE, pursuant to an intercompany administrative services agreement among BHE and its subsidiaries. Please refer to Berkshire Hathaway Energy's Item 11 in this Annual Report on Form 10-K for executive compensation information for Mr. Abel.

(6) Mr. Reiten resigned as a director and officer of PacifiCorp effective December 31, 2016.

Pension Benefits

The following table sets forth certain information regarding the defined benefit pension plan accounts held by each of PacifiCorp's NEOs as of December 31, 2016:

Name	Plan name	Number of years of credited service		Present value of accumulated benefits (1)
Gregory E. Abel	n/a	n/a		n/a
Stefan A. Bird	Retirement	10 years	$	167,745
Cindy A. Crane	Retirement	21 years		433,558
R. Patrick Reiten	Retirement	2 years		16,124
Nikki L. Kobliha	Retirement	12 years		105,491

(1) Amounts are computed using assumptions, other than the expected retirement age, consistent with those used in preparing the related pension disclosures in the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K and are as of December 31, 2016, which is the measurement date for the plans. The expected retirement age assumption has been determined in accordance with Instruction 2 to Item 402(h)(2) of Regulation S-K. For the Retirement Plan calculations of the present value of accumulated benefits, the following assumptions were used: 50% lump sum payment; 35% joint and 100% survivor annuity; and 15% single life annuity. The present value assumptions used in calculating the present value of accumulated benefits for the Retirement Plan were as follows: a discount rate of 4.05%; an expected retirement age of 65; postretirement mortality using the RP-2014 gender specific tables, adjusted for BHE credibility weighted experience, translated to 2011 using MP-2014. 2012 rates were used for MP-2016 and generational mortality improvements from 2012 forward were based on the custom RPEC 2016 model; a lump sum interest rate of 4.05%; and lump sum mortality same as postretirement mortality; blended 50% male and 50% female.

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

The Retirement Plan was restated effective June 1, 2007 to change from a traditional final average pay formula as described above to a cash balance formula for non-union participants. Benefits under the final average pay formula were frozen as of May 31, 2007, and no future benefits will accrue under that formula for non-union participants. Under the cash balance formula, benefits are based on pay credits to each participant's account of 6.5% (5.0% for employees hired after June 30, 2006 and before January 1, 2008) of eligible compensation. Interest is also credited to each participant's account. Employees who were age 40 or older as of May 31, 2007 received certain additional transition pay credits for five years from the effective date of the Retirement Plan restatement.

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

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

In 2017, the Retirement Plan was frozen for the remainder of the non-union employees (which include Mr. Bird and Ms. Crane). Pay credits equivalent to those received in the Retirement Plan will be allocated into the K Plus Employee Savings Plan.

Nonqualified Deferred Compensation

The following table sets forth certain information regarding the nonqualified deferred compensation plan accounts held by each of PacifiCorp's NEOs as of December 31, 2016:

Name	Executive contributions in 2016 (1)	Registrant contributions in 2016	Aggregate earnings in 2016	Aggregate withdrawals/ distributions	Aggregate balance as of December 31, 2016 (2)
Gregory E. Abel	$ —	$ —	$ —	$ —	$ —
Stefan A. Bird	—	—	—	—	—
Cindy A. Crane	579,864	—	212,289	—	2,584,801
R. Patrick Reiten		—	125,416	(493,537)	836,789
Nikki L. Kobliha	—	—	—	—	—

(1) The executive contribution amount shown for Ms. Crane represents a deferral of $338,000 of her 2016 compensation and her 2012 LTIP award which was deferred in 2016. The $338,000 deferred compensation and $67,107 of the deferred LTIP award are included in the 2016 total compensation reported for her in the Summary Compensation Table and are not additional compensation. The remaining 2012 LTIP award was earned prior to 2016.

(2) The aggregate balance as of December 31, 2016 shown for Ms. Crane includes $35,397 of compensation previously reported in 2014 in the Summary Compensation Table.

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

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

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

Potential Payments Upon Termination

PacifiCorp's NEOs, other than Mr. Abel, are not generally entitled to severance or enhanced benefits upon termination of employment or change in control. Please refer to Berkshire Hathaway Energy's Item 11 in this Annual Report on Form 10-K for information about potential post-termination payments to Mr. Abel.

The following table sets forth the estimated enhancements to payments pursuant to the termination scenarios indicated for PacifiCorp's NEOs. Payments or benefits that are not enhanced in form or amount upon the occurrence of a particular termination scenario, which include 401(k) and nonqualified deferred compensation account balances and those portions of long-term incentive payments that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2016 and are payable as lump sums unless otherwise noted.

Termination Scenario	Incentive (1)	Pension (2)
Gregory E. Abel:		
Retirement, Voluntary and Involuntary With or Without Cause	$ —	$ —
Death and Disability	—	—
Stefan A. Bird:		
Retirement, Voluntary and Involuntary With or Without Cause	—	54,565
Death and Disability	673,062	54,565
Cindy A. Crane:		
Retirement, Voluntary and Involuntary With or Without Cause	—	24,904
Death and Disability	698,395	24,904
R. Patrick Reiten:		
Retirement, Voluntary and Involuntary With or Without Cause	—	3,782
Death and Disability	775,891	3,782
Nikki L. Kobliha:		
Retirement, Voluntary and Involuntary With or Without Cause	—	3,359
Death and Disability	43,480	3,359

(1) Amounts represent the unvested portion of each NEO's LTIP account, which becomes 100% vested upon death or disability.

(2) Pension values represent the excess of the present value of benefits payable under each termination scenario over the amount already reflected in the Pension Benefits table.

Director Compensation

PacifiCorp's directors do not receive additional compensation for service as directors of PacifiCorp. Compensation information for Messrs. Abel, Bird and Reiten and Ms. Crane for their services as executive officers of PacifiCorp is described above. Compensation information for Messrs. Anderson and Goodman and Ms. Hocken is described in Berkshire Hathaway Energy's Item 11 in this Annual Report on Form 10-K. Ms. Kelly is an executive officer at BHE, but not a named executive officer of BHE. Ms. Kelly resigned as a member of the board of directors of PacifiCorp effective December 31, 2016. Mr. Reiten resigned as a director and officer of PacifiCorp effective December 31, 2016. Mr. Douglas L. Anderson resigned as a member of the board of directors of PacifiCorp effective January 13, 2017.

Compensation Committee Interlocks and Insider Participation

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

MIDAMERICAN FUNDING, MIDAMERICAN ENERGY, NEVADA POWER AND SIERRA PACIFIC

Information required by Item 11 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

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

BERKSHIRE HATHAWAY ENERGY

Beneficial Ownership

BHE is a consolidated subsidiary of Berkshire Hathaway. The balance of BHE's common stock is owned by Mr. Scott (along with family members and related entities) and Mr. Abel. The following table sets forth certain information regarding beneficial ownership of BHE's shares of common stock held by each of its directors, executive officers and all of its directors and executive officers as a group as of February 17, 2017:

Name and Address of Beneficial Owner(1)	Number of Shares Beneficially Owned(2)	Percentage Of Class(2)
Berkshire Hathaway(3)	69,602,161	90.0%
Walter Scott, Jr.(4)	4,100,000	5.3%
Gregory E. Abel	740,961	1.0%
Natalie L. Hocken	—	—
Warren E. Buffett(3)(5)	—	—
Patrick J. Goodman	—	—
Marc D. Hamburg(3)(5)	—	—
All directors and executive officers as a group (6 persons)	4,840,961	6.3%

(1) Unless otherwise indicated, each address is c/o Berkshire Hathaway Energy Company at 666 Grand Avenue, 29th Floor, Des Moines, Iowa 50309.

(2) Includes shares of which the listed beneficial owner is deemed to have the right to acquire beneficial ownership under Rule 13d-3(d) under the Securities Exchange Act, including, among other things, shares which the listed beneficial owner has the right to acquire within 60 days.

(3) Such beneficial owner's address is 1440 Kiewit Plaza, Omaha, Nebraska 68131.

(4) Excludes 2,913,022 shares held by family members and family trusts and corporations, or Scott Family Interests, as to which Mr. Scott disclaims beneficial ownership. Mr. Scott's address is 1000 Kiewit Plaza, Omaha, Nebraska 68131.

(5) Excludes 69,602,161 shares of common stock held by Berkshire Hathaway as to which Messrs. Buffett and Hamburg disclaim beneficial ownership.

The following table sets forth certain information regarding beneficial ownership of Class A and Class B shares of Berkshire Hathaway's common stock held by each of BHE's directors, executive officers and all of its directors and executive officers as a group as of February 17, 2017:

Name and Address of Beneficial Owner(1)	Number of Shares Beneficially Owned(2)	Percentage Of Class(2)
Walter Scott, Jr.(3)(4)		
Class A	100	*
Class B	—	—
Gregory E. Abel(4)		
Class A	5	*
Class B	2,363	*
Natalie L. Hocken		
Class A	—	—
Class B	—	—
Warren E. Buffett(5)		
Class A	295,161	38.1%
Class B	79,345	*
Patrick J. Goodman		
Class A	5	*
Class B	786	*
Marc D. Hamburg(5)		
Class A	—	—
Class B	—	—
All directors and executive officers as a group (6 persons)		
Class A	295,271	38.1%
Class B	82,494	*

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

(1) Unless otherwise indicated, each address is c/o Berkshire Hathaway Energy Company at 666 Grand Avenue, 29th Floor, Des Moines, Iowa 50309.

(2) Includes shares of which the listed beneficial owner is deemed to have the right to acquire beneficial ownership under Rule 13d-3(d) under the Securities Exchange Act, including, among other things, shares which the listed beneficial owner has the right to acquire within 60 days.

(3) Does not include 10 Class A shares owned by Mr. Scott's wife. Mr. Scott's address is 1000 Kiewit Plaza, Omaha, Nebraska 68131.

(4) In accordance with a shareholders' agreement, as amended on December 7, 2005, based on an assumed value for BHE's common stock and the closing price of Berkshire Hathaway common stock on February 17, 2017, Mr. Scott and the Scott Family Interests and Mr. Abel would be entitled to exchange their shares of BHE common stock for either 15,255 and 1,612, respectively, shares of Berkshire Hathaway Class A stock or 22,881,664 and 2,417,563, respectively, shares of Berkshire Hathaway Class B stock. Assuming an exchange of all available BHE shares into either Berkshire Hathaway Class A shares or Berkshire Hathaway Class B shares, Mr. Scott and the Scott Family Interests would beneficially own 1.9% of the outstanding shares of Berkshire Hathaway Class A stock or 1.7% of the outstanding shares of Berkshire Hathaway Class B stock, and Mr. Abel would beneficially own less than 1% of the outstanding shares of either class of stock.

(5) Such beneficial owner's address is 1440 Kiewit Plaza, Omaha, Nebraska 68131.

Other Matters

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

PACIFICORP

Beneficial Ownership

PacifiCorp is a consolidated subsidiary of BHE. PacifiCorp's common stock is indirectly owned by BHE, 666 Grand Avenue, Suite 500, Des Moines, Iowa 50309-2580. BHE is a consolidated subsidiary of Berkshire Hathaway that, as of February 17, 2017, owns 90.0% of BHE's common stock. The balance of BHE's common stock is owned by Walter Scott, Jr. (along with family members and related entities), a member of BHE's Board of Directors, and Gregory E. Abel, PacifiCorp's Chairman and Chief Executive Officer.

None of PacifiCorp's executive officers or directors owns shares of its preferred stock. The following table sets forth certain information regarding the beneficial ownership of BHE's common stock and the Class A and Class B shares of Berkshire Hathaway common stock held by each of PacifiCorp's directors, executive officers and all of its directors and executive officers as a group as of February 17, 2017:

	BHE		Berkshire Hathaway			
	Common Stock		Class A Common Stock		Class B Common Stock	
Beneficial Owner	Number of Shares Beneficially Owned(1)	Percentage of Class(1)	Number of Shares Beneficially Owned(1)	Percentage of Class(1)	Number of Shares Beneficially Owned(1)	Percentage of Class(1)
Gregory E. Abel (2)	740,961	1.0%	5	*	2,363	*
Stefan A. Bird	—	—	—	—	—	—
Cindy A. Crane	—	—	—	—	—	—
Patrick J. Goodman	—	—	5	*	786	*
Natalie L. Hocken	—	—	—	—	—	—
Nikki L. Kobliha	—	—	—	—	—	—
All executive officers and directors as a group (6 persons)	740,961	1.0%	10	*	3,149	*

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

(1) Includes shares of which the listed beneficial owner is deemed to have the right to acquire beneficial ownership under Rule 13d-3(d) under the Securities Exchange Act, including, among other things, shares which the listed beneficial owner has the right to acquire within 60 days.

(2) In accordance with a shareholders' agreement, as amended on December 7, 2005, based on an assumed value for BHE's common stock and the closing price of Berkshire Hathaway common stock on February 17, 2017, Mr. Abel would be entitled to exchange his shares of BHE common stock for either 1,612 shares of Berkshire Hathaway Class A stock or 2,417,563 shares of Berkshire Hathaway Class B stock. Assuming an exchange of all available BHE shares into either Berkshire Hathaway Class A shares or Berkshire Hathaway Class B shares, Mr. Abel would beneficially own less than 1% of the outstanding shares of either class of stock.

Other Matters

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

MIDAMERICAN FUNDING, MIDAMERICAN ENERGY, NEVADA POWER AND SIERRA PACIFIC

Information required by Item 12 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

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

BERKSHIRE HATHAWAY ENERGY

Certain Relationships and Related Transactions

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

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

As of December 31, 2016 and 2015, certain Berkshire Hathaway subsidiaries held variable-rate junior subordinated debentures due from BHE totaling $0.9 billion and $2.9 billion, respectively. Principal repayments on these securities totaled $2.0 billion and $850 million during 2016 and 2015, respectively, and interest expense on these securities totaled $65 million and $104 million during 2016 and 2015, respectively.

Director Independence

Based on the standards of the New York Stock Exchange LLC, on which the common stock of BHE's majority owner, Berkshire Hathaway, is listed, BHE's Board of Directors has determined that none of its directors are considered independent because of their employment by Berkshire Hathaway or BHE or their ownership of BHE's common stock.

PACIFICORP

Certain Relationships and Related Transactions

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

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

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

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

Director Independence

Because PacifiCorp's common stock is indirectly, wholly owned by BHE and its Board of Directors consists of BHE and PacifiCorp employees, PacifiCorp is not required to have independent directors or audit, nominating or compensation committees consisting of independent directors.

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

MIDAMERICAN FUNDING, MIDAMERICAN ENERGY, NEVADA POWER AND SIERRA PACIFIC

Information required by Item 13 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

Item 14. Principal Accountant Fees and Services

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

	Berkshire Hathaway Energy	PacifiCorp	MidAmerican Funding	MidAmerican Energy	Nevada Power	Sierra Pacific
2016						
Audit fees(1)	$ 9.1	$ 1.5	$ 1.2	$ 1.1	$ 0.9	$ 1.1
Audit-related fees(2)	0.8	0.2	0.2	0.2	—	—
Tax fees(3)	0.1	—	—	—	—	—
Total	$ 10.0	$ 1.7	$ 1.4	$ 1.3	$ 0.9	$ 1.1
2015						
Audit fees(1)	$ 9.3	$ 1.7	$ 1.2	$ 1.1	$ 0.9	$ 0.9
Audit-related fees(2)	0.9	0.3	0.2	0.1	—	—
Tax fees(3)	0.1	—	—	—	—	—
Total	$ 10.3	$ 2.0	$ 1.4	$ 1.2	$ 0.9	$ 0.9

(1) Audit fees include fees for the audit of the consolidated financial statements and interim reviews of the quarterly financial statements for each Registrant, audit services provided in connection with required statutory audits of certain of BHE's subsidiaries and comfort letters, consents and other services related to SEC matters for each Registrant.

(2) Audit-related fees primarily include fees for assurance and related services for any other statutory or regulatory requirements, audits of certain employee benefit plans and consultations on various accounting and reporting matters.

(3) Tax fees include fees for services relating to tax compliance, tax planning and tax advice. These services include assistance regarding federal, state and international tax compliance, tax return preparation and tax audits.

The audit committee has considered whether the non-audit services provided to the Registrants by the Deloitte Entities impaired the independence of the Deloitte Entities and concluded that they did not. All of the services performed by the Deloitte Entities were pre-approved in accordance with the pre-approval policy adopted by the audit committee. The policy provides guidelines for the audit, audit-related, tax and other non-audit services that may be provided by the Deloitte Entities to the Registrants. The policy (a) identifies the guiding principles that must be considered by the audit committee in approving services to ensure that the Deloitte Entities' independence is not impaired; (b) describes the audit, audit-related and tax services that may be provided and the non-audit services that are prohibited; and (c) sets forth pre-approval requirements for all permitted services. Under the policy, requests to provide services that require specific approval by the audit committee will be submitted to the audit committee by both the Registrants' independent auditor and BHE's Chief Financial Officer. All requests for services to be provided by the independent auditor that do not require specific approval by the audit committee will be submitted to BHE's Chief Financial Officer and must include a detailed description of the services to be rendered. BHE's Chief Financial Officer will determine whether such services are included within the list of services that have received the general pre-approval of the audit committee. The audit committee will be informed on a timely basis of any such services rendered by the independent auditor.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements and Schedules

(i) Financial Statements

(ii) Financial Statement Schedules

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

(b) Exhibits

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

Schedule I

Berkshire Hathaway Energy Company
Parent Company Only
Condensed Balance Sheets
As of December 31,
(Amounts in millions)

	2016	2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 33	$ 23
Accounts receivable	21	16
Notes receivable - affiliate	105	—
Income tax receivable	—	167
Other current assets	2	2
Total current assets	161	208
Investments in subsidiaries	33,400	32,505
Other investments	1,338	1,389
Goodwill	1,221	1,221
Other assets	1,171	1,340
Total assets	$ 37,291	$ 36,663
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and other current liabilities	$ 357	$ 306
Notes payable - affiliate	194	—
Short-term debt	834	253
Current portion of BHE senior debt	400	—
Total current liabilities	1,785	559
BHE senior debt	7,418	7,814
BHE junior subordinated debentures	944	2,944
Notes payable - affiliate	1,859	1,985
Other long-term liabilities	942	946
Total liabilities	12,948	14,248
Equity:		
BHE shareholders' equity:		
Common stock - 115 shares authorized, no par value, 77 shares issued and outstanding	—	—
Additional paid-in capital	6,390	6,403
Retained earnings	19,448	16,906
Accumulated other comprehensive loss, net	(1,511)	(908)
Total BHE shareholders' equity	24,327	22,401
Noncontrolling interest	16	14
Total equity	24,343	22,415
Total liabilities and equity	$ 37,291	$ 36,663

The accompanying notes are an integral part of this financial statement schedule.

Berkshire Hathaway Energy Company
Parent Company Only (continued)
Condensed Statements of Operations
For the years ended December 31,
(Amounts in millions)

	2016	2015	2014
Operating costs and expenses:			
General and administration	$ 51	$ 58	$ 51
Depreciation and amortization	4	3	3
Total operating costs and expenses	55	61	54
Operating loss	(55)	(61)	(54)
Other income (expense):			
Interest expense	(527)	(556)	(476)
Other, net	37	14	4
Total other income (expense)	(490)	(542)	(472)
Loss before income tax benefit and equity income	(545)	(603)	(526)
Income tax benefit	(285)	(330)	(221)
Equity income	2,805	2,646	2,402
Net income	2,545	2,373	2,097
Net income attributable to noncontrolling interest	3	3	2
Net income attributable to BHE shareholders	$ 2,542	$ 2,370	$ 2,095

The accompanying notes are an integral part of this financial statement schedule.

Berkshire Hathaway Energy Company
Parent Company Only (continued)
Condensed Statements of Comprehensive Income
For the years ended December 31,
(Amounts in millions)

	2016	2015	2014
Net income	$ 2,545	$ 2,373	$ 2,097
Other comprehensive loss, net of tax	(603)	(414)	(397)
Comprehensive income	1,942	1,959	1,700
Comprehensive income attributable to noncontrolling interests	3	3	2
Comprehensive income attributable to BHE shareholders	$ 1,939	$ 1,956	$ 1,698

The accompanying notes are an integral part of this financial statement schedule.

Berkshire Hathaway Energy Company
Parent Company Only (continued)
Condensed Statements of Cash Flows
For the years ended December 31,
(Amounts in millions)

	2016	2015	2014
Cash flows from operating activities	$ 2,760	$ 2,528	$ 1,937
Cash flows from investing activities:			
Investments in subsidiaries	(1,080)	(1,506)	(4,937)
Purchases of investments	(24)	(36)	(56)
Proceeds from sale of investments	20	47	35
Notes receivable from affiliate, net	(307)	19	(55)
Other, net	(5)	(7)	(7)
Net cash flows from investing activities	(1,396)	(1,483)	(5,020)
Cash flows from financing activities:			
Proceeds from BHE senior debt	—	—	1,478
Proceeds from BHE junior subordinated debentures	—	—	1,500
Proceeds from issuance of BHE common stock	—	—	—
Repayments of BHE senior debt	—	—	(250)
Repayments of BHE subordinated debt	(2,000)	(850)	(300)
Common stock purchases	—	(36)	—
Net proceeds from (repayments of) short-term debt	581	(142)	395
Notes payable to affiliate, net	69	4	(30)
Other, net	(4)	(1)	1
Net cash flows from financing activities	(1,354)	(1,025)	2,794
Net change in cash and cash equivalents	10	20	(289)
Cash and cash equivalents at beginning of year	23	3	292
Cash and cash equivalents at end of year	$ 33	$ 23	$ 3

The accompanying notes are an integral part of this financial statement schedule.

BERKSHIRE HATHAWAY ENERGY COMPANY
NOTES TO CONDENSED FINANCIAL STATEMENTS

Basis of Presentation - The condensed financial information of BHE investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in subsidiaries are recorded in the Condensed Balance Sheets. The income from operations of subsidiaries is reported on a net basis as equity income in the Condensed Statements of Operations.

Other investments - BHE's investment in BYD Company Limited ("BYD") common stock is accounted for as an available-for-sale security with changes in fair value recognized in AOCI. As of December 31, 2016 and 2015, the fair value of BHE's investment in BYD common stock was $1,185 million and $1,238 million, respectively, which resulted in a unrealized gain of $953 million and $1,006 million as of December 31, 2016 and 2015, respectively.

Dividends and distributions from subsidiaries - Cash dividends paid to BHE by its subsidiaries for the years ended December 31, 2016, 2015 and 2014 were $3.0 billion, $3.0 billion and $2.3 billion, respectively. In January and February 2017, BHE received cash dividends from its subsidiaries totaling $160 million.

Guarantees and commitments - BHE has issued guarantees up to a maximum of $336 million in support of various obligations of consolidated subsidiaries and commitments to provide equity contributions in support of renewable tax equity investments totaling $288 million.

See the notes to the consolidated BHE financial statements in Part II, Item 8 for other disclosures regarding long-term obligations (Notes 8, 9 and 10) and shareholders' equity (Note 17).

BERKSHIRE HATHAWAY ENERGY COMPANY
CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE THREE YEARS ENDED DECEMBER 31, 2016
(Amounts in millions)

Column A	Column B	Column C		Column D	Column E
Description	Balance at Beginning of Year	Charged to Income	Acquisition Reserves	Deductions	Balance at End of Year
Reserves Deducted From Assets To Which They Apply:					
Reserve for uncollectible accounts receivable:					
Year ended 2016	$ 31	$ 39	$ —	$ (37)	$ 33
Year ended 2015	37	33	—	(39)	31
Year ended 2014	33	37	—	(33)	37
Reserves Not Deducted From Assets[1]:					
Year ended 2016	$ 13	$ 5	$ —	$ (5)	$ 13
Year ended 2015	11	7	—	(5)	13
Year ended 2014	9	12	—	(10)	11

The notes to the consolidated BHE financial statements are an integral part of this financial statement schedule.

(1) Reserves not deducted from assets relate primarily to estimated liabilities for losses retained by BHE for workers compensation, public liability and property damage claims.

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2016	**2015**
ASSETS		
Current assets:		
Receivables from affiliates	$ 2	$ 2
Investments in and advances to subsidiaries	6,718	6,144
Total assets	$ 6,720	$ 6,146
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities:		
Interest accrued and other current liabilities	$ 7	$ 7
Payable to affiliate	301	288
Long-term debt	326	326
Total liabilities	634	621
Member's equity:		
Paid-in capital	1,679	1,679
Retained earnings	4,407	3,876
Accumulated other comprehensive loss, net	—	(30)
Total member's equity	6,086	5,525
Total liabilities and member's equity	$ 6,720	$ 6,146

The accompanying notes are an integral part of this financial statement schedule.

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2016	**2015**	**2014**
Interest expense	$ 22	$ 22	$ 22
Loss before income taxes	(22)	(22)	(22)
Income tax benefit	(9)	(8)	(9)
Equity in undistributed earnings of subsidiaries	545	472	422
Net income	$ 532	$ 458	$ 409

The accompanying notes are an integral part of this financial statement schedule.

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2016	**2015**	**2014**
Net income	$ 532	$ 458	$ 409
Total other comprehensive income (loss), net of tax	3	(7)	(12)
Comprehensive income	$ 535	$ 451	$ 397

The accompanying notes are an integral part of this financial statement schedule.

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2016	**2015**	**2014**
Net cash flows from operating activities	$ (13)	$ (13)	$ (13)
Net cash flows from investing activities	—	—	—
Net cash flows from financing activities:			
Net change in amounts payable to subsidiary	13	13	13
Net cash flows from financing activities	13	13	13
Net change in cash and cash equivalents	—	—	—
Cash and cash equivalents at beginning of year	—	—	—
Cash and cash equivalents at end of year	$ —	$ —	$ —

The accompanying notes are an integral part of this financial statement schedule.

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
NOTES TO CONDENSED FINANCIAL STATEMENTS

Incorporated by reference are MidAmerican Funding, LLC and Subsidiaries Consolidated Statements of Changes in Equity for the three years ended December 31, 2016 in Part II, Item 8.

Basis of Presentation - The condensed financial information of MidAmerican Funding, LLC's ("MidAmerican Funding's") investments in subsidiaries is presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in and advances to subsidiaries are recorded on the Condensed Balance Sheets. The income from operations of the subsidiaries is reported on a net basis as equity in undistributed earnings of subsidiary companies on the Condensed Statements of Operations.

Payable to Affiliate - MHC, Inc. ("MHC") settles all obligations of MidAmerican Funding including primarily interest costs on, and repayments of, MidAmerican Funding's long-term debt. Net amounts paid by MHC on behalf of MidAmerican Funding totaled $13 million, $13 million and $13 million for the years 2016, 2015 and 2014, respectively.

See the notes to the consolidated MidAmerican Funding financial statements in Part II, Item 8 for other disclosures.

MHC INC.
PARENT COMPANY ONLY
CONDENSED BALANCE SHEETS
(Amounts in millions)

	As of December 31, 2016	As of December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1	$ —
Receivables from affiliates	1	1
Receivable from parent	301	288
Investments and nonregulated property, net	12	12
Goodwill	1,270	1,270
Investments in and advances to subsidiaries	5,181	4,724
Total assets	$ 6,766	$ 6,295
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Payables to affiliates	$ 44	$ 146
Deferred income taxes	4	5
Total liabilities	48	151
Shareholder's equity:		
Paid-in capital	2,430	2,430
Retained earnings	4,288	3,744
Accumulated other comprehensive loss, net	—	(30)
Total shareholder's equity	6,718	6,144
Total liabilities and shareholder's equity	$ 6,766	$ 6,295

The accompanying notes are an integral part of this financial statement schedule.

MHC INC.
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2016	**2015**	**2014**
Other income	$ 1	$ 1	$ 2
Income before income taxes	1	1	2
Income tax expense	—	—	1
Equity in undistributed earnings of subsidiaries	544	471	421
Net income	$ 545	$ 472	$ 422

The accompanying notes are an integral part of this financial statement schedule.

MHC INC.
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2016	**2015**	**2014**
Net income	$ 545	$ 472	$ 422
Total other comprehensive income (loss), net of tax	3	(7)	(12)
Comprehensive income	$ 548	$ 465	$ 410

The accompanying notes are an integral part of this financial statement schedule.

MHC INC.
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31, 2016	2015	2014
Net cash flows from operating activities	$ 1	$ 1	$ —
Net cash flows from investing activities:			
Dividend from subsidiary	—	16	—
Net change in amounts receivable from parent	(13)	(13)	(13)
Other	—	(1)	3
Net cash flows from investing activities	(13)	2	(10)
Net cash flows from financing activities:			
Capital expenditures	(1)	—	—
Net change in amounts payable to subsidiaries	5	(7)	10
Net change in note payable to Berkshire Hathaway Energy Company	9	3	1
Net cash flows from financing activities	13	(4)	11
Net change in cash and cash equivalents	1	(1)	1
Cash and cash equivalents at beginning of year	—	1	—
Cash and cash equivalents at end of year	$ 1	$ —	$ 1

The accompanying notes are an integral part of this financial statement schedule.

MHC INC.
PARENT COMPANY ONLY
NOTES TO CONDENSED FINANCIAL STATEMENTS

Incorporated by reference are MHC Inc. and Subsidiaries Consolidated Statements of Changes in Equity for the three years ended December 31, 2016, in Part IV, Item 15(c).

Basis of Presentation - The condensed financial information of MHC Inc.'s ("MHC's") investments in subsidiaries is presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in and advances to subsidiaries are recorded on the Condensed Balance Sheets. The income from operations of the subsidiaries is reported on a net basis as equity in undistributed earnings of subsidiary companies on the Condensed Statements of Operations.

Receivable from Parent - MHC settles all obligations of MidAmerican Funding, LLC ("MidAmerican Funding") including primarily interest costs on MidAmerican Funding's long-term debt. Net amounts paid by MHC on behalf of MidAmerican Funding totaled $13 million, $13 million and $13 million for the years 2016, 2015 and 2014, respectively.

Note Payable to Berkshire Hathaway Energy Company - On January 1, 2016, MidAmerican Energy Company transferred the assets and liabilities of its unregulated retail services business to a subsidiary of Berkshire Hathaway Energy Company ("BHE"). The transfer repaid $117 million of MHC's note payable to BHE. See Note 3 of MidAmerican Energy Company's Notes to Financial Statements in Part II, Item 8 for further discussion of the transfer.

See the notes to the consolidated MHC financial statements in Part IV, Item 15(c) for other disclosures.

MIDAMERICAN ENERGY COMPANY
VALUATION AND QUALIFYING ACCOUNTS
FOR THE THREE YEARS ENDED DECEMBER 31, 2016
(Amounts in millions)

Column A Description	Column B Balance at Beginning of Year	Column C Additions Charged to Income	Column D Deductions	Column E Balance at End of Year
Reserves Deducted From Assets To Which They Apply:				
Reserve for uncollectible accounts receivable:				
Year ended 2016	$ 6	$ 7	$ (6)	$ 7
Year ended 2015	$ 7	$ 7	$ (8)	$ 6
Year ended 2014	$ 10	$ 7	$ (10)	$ 7
Reserves Not Deducted From Assets[(1)]:				
Year ended 2016	$ 13	$ 5	$ (5)	$ 13
Year ended 2015	$ 11	$ 7	$ (5)	$ 13
Year ended 2014	$ 9	$ 12	$ (10)	$ 11

(1) Reserves not deducted from assets include estimated liabilities for losses retained by MidAmerican Energy for workers compensation, public liability and property damage claims.

SCHEDULE II

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
MHC INC. AND SUBSIDIARIES
CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE THREE YEARS ENDED DECEMBER 31, 2016
(Amounts in millions)

Column A Description	Column B Balance at Beginning of Year	Column C Additions Charged to Income	Column D Deductions	Column E Balance at End of Year
Reserves Deducted From Assets To Which They Apply:				
Reserve for uncollectible accounts receivable:				
Year ended 2016	$ 6	$ 7	$ (6)	$ 7
Year ended 2015	$ 7	$ 7	$ (8)	$ 6
Year ended 2014	$ 10	$ 7	$ (10)	$ 7
Reserves Not Deducted From Assets [(1)]:				
Year ended 2016	$ 13	$ 5	$ (5)	$ 13
Year ended 2015	$ 11	$ 7	$ (5)	$ 13
Year ended 2014	$ 9	$ 12	$ (10)	$ 11

(1) Reserves not deducted from assets include primarily estimated liabilities for losses retained by MidAmerican Funding and MHC for workers compensation, public liability and property damage claims.

Item 15(c) MHC Inc. Consolidated Financial Statements

The accompanying Consolidated Financial Statements of MHC Inc., the direct wholly owned subsidiary of MidAmerican Funding, are being provided pursuant to Rule 3-16 of the U. S. Securities and Exchange Commission's Regulation S-X. The purpose of these financial statements is to provide information about the assets and equity interests that collateralize MidAmerican Funding's long-term debt and that, upon the occurrence of any triggering event under the collateral agreement, would be available to satisfy the applicable debt obligations.

MHC Inc. and Subsidiaries

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
MHC Inc.
Des Moines, Iowa

We have audited the accompanying consolidated balance sheets of MHC Inc. and subsidiaries ("MHC") as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2016. Our audits also included MHC's financial statement schedules listed in the Index at Item 15(a)(ii). These financial statements and financial statement schedules are the responsibility of MHC's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States) and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. MHC is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of MHC's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of MHC Inc. and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

As discussed in Note 3 to the consolidated financial statements, MidAmerican Energy Company transferred its assets and liabilities of its unregulated retail services business to a subsidiary of its parent, Berkshire Hathaway Energy Company, on January 1, 2016.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 24, 2017

MHC INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31, 2016	As of December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 15	$ 103
Receivables, net	284	343
Income taxes receivable	9	104
Inventories	264	238
Other current assets	35	58
Total current assets	607	846
Property, plant and equipment, net	12,835	11,737
Goodwill	1,270	1,270
Regulatory assets	1,161	1,044
Investments and restricted cash and investments	655	636
Receivable from affiliate	301	288
Other assets	216	138
Total assets	$ 17,045	$ 15,959

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

MHC INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2016	**2015**
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 302	$ 426
Accrued interest	45	46
Accrued property, income and other taxes	138	125
Note payable to affiliate	31	139
Short-term debt	99	—
Current portion of long-term debt	250	34
Other current liabilities	159	166
Total current liabilities	1,024	936
Long-term debt	4,051	4,237
Deferred income taxes	3,568	3,056
Regulatory liabilities	883	831
Asset retirement obligations	510	488
Other long-term liabilities	291	267
Total liabilities	10,327	9,815
Commitments and contingencies (Note 15)		
Shareholder's equity:		
Common stock - no par value, 1,000 shares authorized, 1,000 shares issued and outstanding	—	—
Additional paid-in capital	2,430	2,430
Retained earnings	4,288	3,744
Accumulated other comprehensive loss, net	—	(30)
Total shareholder's equity	6,718	6,144
Total liabilities and shareholder's equity	$ 17,045	$ 15,959

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

MHC INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2016	**2015**	**2014**
Operating revenue:			
Regulated electric	$ 1,985	$ 1,837	$ 1,817
Regulated gas and other	646	678	1,027
Total operating revenue	2,631	2,515	2,844
Operating costs and expenses:			
Cost of fuel, energy and capacity	410	433	532
Cost of gas sold and other	371	407	738
Operations and maintenance	693	707	720
Depreciation and amortization	479	407	351
Property and other taxes	112	110	108
Total operating costs and expenses	2,065	2,064	2,449
Operating income	566	451	395
Other income and (expense):			
Interest expense	(196)	(184)	(175)
Allowance for borrowed funds	8	8	16
Allowance for equity funds	19	20	39
Other, net	18	20	18
Total other income and (expense)	(151)	(136)	(102)
Income before income tax benefit	415	315	293
Income tax benefit	(130)	(141)	(113)
Income from continuing operations	545	456	406
Discontinued operations (Note 3):			
Income from discontinued operations	—	22	28
Income tax expense	—	6	12
Income on discontinued operations	—	16	16
Net income	$ 545	$ 472	$ 422

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

MHC INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2016	2015	2014
Net income	$ 545	$ 472	$ 422
Other comprehensive income (loss), net of tax:			
Unrealized gains on available-for-sale securities, net of tax of $1, $- and $1	3	—	1
Unrealized losses on cash flow hedges, net of tax of $-, $(4) and $(10)	—	(7)	(13)
Total other comprehensive income (loss), net of tax	3	(7)	(12)
Comprehensive income	$ 548	$ 465	$ 410

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

MHC INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Amounts in millions)

	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Total Equity
Balance, December 31, 2013	$ 2,430	$ 2,850	$ (11)	$ 5,269
Net income	—	422	—	422
Other comprehensive loss	—	—	(12)	(12)
Balance, December 31, 2014	2,430	3,272	(23)	5,679
Net income	—	472	—	472
Other comprehensive loss	—	—	(7)	(7)
Balance, December 31, 2015	2,430	3,744	(30)	6,144
Net income	—	545	—	545
Other comprehensive income	—	—	3	3
Transfer to affiliate (Note 3)	—	—	27	27
Other equity transactions	—	(1)	—	(1)
Balance, December 31, 2016	$ 2,430	$ 4,288	$ —	$ 6,718

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

MHC INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2016	**2015**	**2014**
Cash flows from operating activities:			
Net income	$ 545	$ 472	$ 422
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	479	407	351
Deferred income taxes and amortization of investment tax credits	362	276	298
Changes in other assets and liabilities	47	49	47
Other, net	(92)	(70)	(49)
Changes in other operating assets and liabilities:			
Receivables, net	(61)	93	(2)
Inventories	(27)	(53)	44
Derivative collateral, net	5	33	(53)
Contributions to pension and other postretirement benefit plans, net	(6)	(8)	(2)
Accounts payable	39	(76)	30
Accrued property, income and other taxes, net	107	213	(253)
Other current assets and liabilities	8	12	—
Net cash flows from operating activities	1,406	1,348	833
Net cash flows from investing activities:			
Utility construction expenditures	(1,636)	(1,446)	(1,526)
Purchases of available-for-sale securities	(138)	(142)	(88)
Proceeds from sales of available-for-sale securities	158	135	80
Proceeds from sales of other investments	2	13	10
Other, net	(13)	(11)	(8)
Net cash flows from investing activities	(1,627)	(1,451)	(1,532)
Net cash flows from financing activities:			
Proceeds from long-term debt	62	649	840
Repayments of long-term debt	(38)	(426)	(356)
Net change in amounts receivable from/payable to affiliates	9	3	1
Net proceeds from (repayments of) short-term debt	99	(50)	50
Other, net	1	—	—
Net cash flows from financing activities	133	176	535
Net change in cash and cash equivalents	(88)	73	(164)
Cash and cash equivalents at beginning of year	103	30	194
Cash and cash equivalents at end of year	$ 15	$ 103	$ 30

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

MHC INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Company Organization

MHC Inc. ("MHC") is an Iowa corporation with MidAmerican Funding, LLC ("MidAmerican Funding") as its sole shareholder. MidAmerican Funding is an Iowa limited liability company with Berkshire Hathaway Energy Company ("BHE") as its sole member. BHE is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway"). MHC constitutes substantially all of MidAmerican Funding's assets, liabilities and business activities except those related to MidAmerican Funding's long-term debt securities. MHC conducts no business other than the ownership of its subsidiaries and related corporate services. MHC's principal subsidiary is MidAmerican Energy Company ("MidAmerican Energy"), a public utility with electric and natural gas operations. Direct wholly owned nonregulated subsidiaries of MHC are Midwest Capital Group, Inc. and MEC Construction Services Co.

(2) Summary of Significant Accounting Policies

In addition to the following significant accounting policies, refer to Note 2 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K for significant accounting policies of MHC.

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of MHC and its subsidiaries in which it held a controlling financial interest as of the date of the financial statement. Intercompany accounts and transactions have been eliminated, other than those between rate-regulated operations. MHC has evaluated subsequent events through February 24, 2017, which is the date the Consolidated Financial Statements were issued.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired when MidAmerican Funding purchased MHC. MHC evaluates goodwill for impairment at least annually and completed its annual review as of October 31. When evaluating goodwill for impairment, MHC estimates the fair value of the reporting unit. If the carrying amount of a reporting unit, including goodwill, exceeds the estimated fair value, then the identifiable assets, including identifiable intangible assets, and liabilities of the reporting unit are estimated at fair value as of the current testing date. The excess of the estimated fair value of the reporting unit over the current estimated fair value of net assets establishes the implied value of goodwill. The excess of the recorded goodwill over the implied goodwill value is charged to earnings as an impairment loss. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. MHC uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings and regulatory asset value; and an appropriate discount rate. In estimating future cash flows, MHC incorporates current market information, as well as historical factors. As such, the determination of fair value incorporates significant unobservable inputs. During 2016, 2015 and 2014, MHC did not record any goodwill impairments.

(3) Discontinued Operations

Refer to Note 3 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K. The transfer of MidAmerican Energy's unregulated retail services business to a subsidiary of BHE repaid $117 million of MHC's note payable to BHE.

(4) Property, Plant and Equipment, Net

Refer to Note 4 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K. In addition to MidAmerican Energy's property, plant and equipment, net, MHC had gross nonregulated property of $22 million as of December 31, 2016 and 2015, related accumulated depreciation and amortization of $9 million and $8 million as of December 31, 2016 and 2015, and construction work-in-progress of $1 million as of December 31, 2016, which consisted primarily of a corporate aircraft owned by MHC.

(5) Jointly Owned Utility Facilities

Refer to Note 5 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(6) Regulatory Matters

Refer to Note 6 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(7) Investments and Restricted Cash and Investments

Refer to Note 7 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K. In addition to MidAmerican Energy's investments and restricted cash and investments, MHC had corporate-owned life insurance policies in a Rabbi trust owned by MHC with a total cash surrender value of $2 million as of December 31, 2016 and 2015.

(8) Short-Term Debt and Credit Facilities

Refer to Note 8 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K. In addition to MidAmerican Energy's credit facilities, MHC has a $4 million unsecured credit facility, which expires in June 2017 and has a variable interest rate based on LIBOR plus a spread. As of December 31, 2016 and 2015, there were no borrowings outstanding under this credit facility. As of December 31, 2016, MHC was in compliance with the covenants of its credit facility.

(9) Long-Term Debt

Refer to Note 9 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(10) Income Taxes

MHC's income tax benefit from continuing operations consists of the following for the years ended December 31 (in millions):

	2016	2015	2014
Current:			
Federal	$ (478)	$ (411)	$ (407)
State	(14)	(6)	(3)
	(492)	(417)	(410)
Deferred:			
Federal	367	282	296
State	(4)	(5)	2
	363	277	298
Investment tax credits	(1)	(1)	(1)
Total	$ (130)	$ (141)	$ (113)

A reconciliation of the federal statutory income tax rate to MHC's effective income tax rate applicable to income before income tax benefit from continuing operations is as follows for the years ended December 31:

	2016	2015	2014
Federal statutory income tax rate	35 %	35 %	35 %
Income tax credits	(60)	(67)	(63)
State income tax, net of federal income tax benefit	(3)	(2)	—
Effects of ratemaking	(3)	(12)	(9)
Other, net	—	1	(2)
Effective income tax rate	(31)%	(45)%	(39)%

Income tax credits relate primarily to production tax credits earned by MidAmerican Energy's wind-powered generating facilities. 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.

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

	2016	2015
Deferred income tax assets:		
Regulatory liabilities	$ 333	$ 327
Derivative contracts	—	—
Asset retirement obligations	230	214
Employee benefits	66	66
Other	82	97
Total deferred income tax assets	711	704
Deferred income tax liabilities:		
Depreciable property	(3,767)	(3,326)
Regulatory assets	(471)	(418)
Other	(41)	(16)
Total deferred income tax liabilities	(4,279)	(3,760)
Net deferred income tax liability	$ (3,568)	$ (3,056)

As of December 31, 2016, MHC has available $25 million of state tax carryforwards, principally related to $549 million of net operating losses, that expire at various intervals between 2017 and 2035.

The United States Internal Revenue Service has closed its examination of BHE's income tax returns through December 31, 2009, including components related to MHC. In addition, state jurisdictions have closed their examinations of MidAmerican Energy's income tax returns for Iowa through December 31, 2012, for Illinois through December 31, 2008, and for other jurisdictions through December 31, 2009.

A reconciliation of the beginning and ending balances of MHC's net unrecognized tax benefits is as follows for the years ended December 31 (in millions):

	2016	2015
Beginning balance	$ 10	$ 26
Additions based on tax positions related to the current year	—	4
Additions for tax positions of prior years	10	46
Reductions based on tax positions related to the current year	(2)	(6)
Reductions for tax positions of prior years	(8)	(46)
Statute of limitations	—	(5)
Settlements	—	(6)
Interest and penalties	—	(3)
Ending balance	$ 10	$ 10

As of December 31, 2016, MHC had unrecognized tax benefits totaling $30 million that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect MHC's effective income tax rate.

(11) Employee Benefit Plans

Refer to Note 11 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K for additional information regarding MHC's pension, supplemental retirement and postretirement benefit plans.

Pension and postretirement costs allocated by MHC to its parent and other affiliates in each of the years ended December 31, were as follows (in millions):

	2016	2015	2014
Pension costs	$ 4	$ 4	$ 4
Other postretirement costs	(1)	(2)	(2)

(12) Asset Retirement Obligations

Refer to Note 12 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(13) Risk Management and Hedging Activities

Refer to Note 13 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(14) Fair Value Measurements

Refer to Note 14 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(15) Commitments and Contingencies

Refer to Note 15 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

Legal Matters

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

(16) Components of Accumulated Other Comprehensive Loss, Net

Refer to Note 16 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(17) Other Income and (Expense) - Other, Net

Other, net, as shown on the Consolidated Statements of Operations, includes the following other income (expense) items for the years ended December 31 (in millions):

	2016	2015	2014
Corporate-owned life insurance income	$ 8	$ 4	$ 8
Gain on redemption of auction rate securities	5	—	—
Gains on sales of assets and other investments	3	13	—
Leveraged leases	—	1	5
Other, net	2	2	5
Total	$ 18	$ 20	$ 18

MidAmerican Funding recognized a $13 million pre-tax gain on the sale of an investment in a generating facility lease in 2015.

(18) Supplemental Cash Flow Information

The summary of supplemental cash flow information as of and for the years ending December 31 is as follows (in millions):

	2016	2015	2014
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 181	$ 154	$ 144
Income taxes received, net	$ 600	$ 621	$ 143
Supplemental disclosure of non-cash investing and financing transactions:			
Accounts payable related to utility plant additions	$ 131	$ 249	$ 128
Transfer of assets and liabilities to affiliate (note 3)	$ 90	$ —	$ —

(19) Related Party Transactions

The companies identified as affiliates of MHC are Berkshire Hathaway and its subsidiaries, including BHE and its subsidiaries. The basis for the following transactions is provided for in service agreements between MHC and the affiliates.

MHC is reimbursed for charges incurred on behalf of its affiliates. The majority of these reimbursed expenses are for allocated general costs, such as insurance and building rent, and for employee wages, benefits and costs for corporate functions, such as information technology, human resources, treasury, legal and accounting. The amount of such reimbursements was $35 million, $35 million and $37 million for 2016, 2015 and 2014, respectively.

MHC reimbursed BHE in the amount of $6 million, $7 million and $8 million in 2016, 2015 and 2014, respectively, for its share of corporate expenses.

MidAmerican Energy purchases natural gas transportation and storage capacity services from Northern Natural Gas Company, a wholly owned subsidiary of BHE, and coal transportation services from BNSF Railway Company, a wholly-owned subsidiary of Berkshire Hathaway, in the normal course of business at either tariffed or market prices. These purchases totaled $135 million, $165 million and $144 million in 2016, 2015 and 2014, respectively.

MHC has a $300 million revolving credit arrangement carrying interest at the 30-day LIBOR rate plus a spread to borrow from BHE. Outstanding balances are unsecured and due on demand. The outstanding balance was $31 million at an interest rate of 0.885% as of December 31, 2016, and $139 million at an interest rate of 0.494% as of December 31, 2015, and is reflected as note payable to affiliate on the Consolidated Balance Sheet.

BHE has a $100 million revolving credit arrangement carrying interest at the 30-day LIBOR rate plus a spread to borrow from MHC. Outstanding balances are unsecured and due on demand. There were no borrowings outstanding throughout 2016 and 2015.

MHC settles all obligations of MidAmerican Funding including primarily interest costs on MidAmerican Funding's long-term debt. Net amounts paid by MHC on behalf of MidAmerican Funding totaled $13 million for 2016, 2015 and 2014.

MHC had accounts receivable from affiliates of $306 million and $292 million as of December 31, 2016 and 2015, respectively, that are reflected in receivables, net and receivable from affiliate on the Consolidated Balance Sheets. MHC also had accounts payable to affiliates of $12 million as of December 31, 2016 and 2015, that are included in accounts payable on the Consolidated Balance Sheets.

MHC is party to a tax-sharing agreement and is part of the Berkshire Hathaway United States federal income tax return. For current federal and state income taxes, MHC had a payable to BHE of $7 million as of December 31, 2016, and a receivable from BHE of $102 million as of December 31, 2015. MHC received net cash receipts for federal and state income taxes from BHE totaling $600 million, $621 million and $144 million for the years ended December 31, 2016, 2015 and 2014, respectively.

MHC recognizes the full amount of the funded status for its pension and postretirement plans, and amounts attributable to MHC's affiliates that have not previously been recognized through income are recognized as an intercompany balance with such affiliates. MHC adjusts these balances when changes to the funded status of the respective plans are recognized and does not intend to settle the balances currently. Amounts receivable from affiliates attributable to the funded status of employee benefit plans totaled $12 million and $10 million as of December 31, 2016 and 2015, respectively, and similar amounts payable to affiliates totaled $36 million and $29 million, as of December 31, 2016 and 2015, respectively. See Note 11 for further information pertaining to pension and postretirement accounting.

(20) Segment Information

MHC has identified two reportable operating segments: regulated electric and regulated gas. The previously reported nonregulated energy segment consisted substantially of MidAmerican Energy's unregulated retail services business, which was transferred to a subsidiary of BHE and is excluded from the information below related to the statements of operations for all periods presented. The regulated electric segment derives most of its revenue from regulated retail sales of electricity to residential, commercial, and industrial customers and from wholesale sales. The regulated gas segment derives most of its revenue from regulated retail sales of natural gas to residential, commercial, and industrial customers and also obtains revenue by transporting gas owned by others through its distribution system. Pricing for regulated electric and regulated gas sales are established separately by regulatory agencies; therefore, management also reviews each segment separately to make decisions regarding allocation of resources and in evaluating performance. Common operating costs, interest income, interest expense and income tax expense are allocated to each segment based on certain factors, which primarily relate to the nature of the cost. "Other" in the tables below consists principally of the nonregulated subsidiaries of MHC not engaged in the energy business. Refer to Note 10 for a discussion of items affecting income tax (benefit) expense for the regulated electric and gas operating segments.

The following tables provide information on a reportable segment basis (in millions):

	Years Ended December 31,		
	2016	2015	2014
Operating revenue:			
Regulated electric	$ 1,985	$ 1,837	$ 1,817
Regulated gas	637	661	996
Other	9	17	31
Total operating revenue	$ 2,631	$ 2,515	$ 2,844
Depreciation and amortization:			
Regulated electric	$ 436	$ 366	$ 312
Regulated gas	43	41	39
Total depreciation and amortization	$ 479	$ 407	$ 351
Operating income:			
Regulated electric	$ 497	$ 385	$ 319
Regulated gas	68	64	75
Other	1	2	1
Total operating income	$ 566	$ 451	$ 395
Interest expense:			
Regulated electric	$ 178	$ 166	$ 157
Regulated gas	18	17	17
Other	—	1	1
Total interest expense	$ 196	$ 184	$ 175
Income tax (benefit) expense from continuing operations:			
Regulated electric	$ (156)	$ (163)	$ (138)
Regulated gas	22	16	22
Other	4	6	3
Total income tax (benefit) expense from continuing operations	$ (130)	$ (141)	$ (113)
Net income:			
Regulated electric	$ 512	$ 413	$ 361
Regulated gas	32	33	40
Other	1	10	5
Income from continuing operations	545	456	406
Income on discontinued operations	—	16	16
Net income	$ 545	$ 472	$ 422
Utility construction expenditures:			
Regulated electric	$ 1,564	$ 1,365	$ 1,429
Regulated gas	72	81	97
Total utility construction expenditures	$ 1,636	$ 1,446	$ 1,526

	As of December 31,		
	2016	2015	2014
Total assets:			
Regulated electric	$ 15,304	$ 14,161	$ 13,041
Regulated gas	1,424	1,330	1,296
Other	317	468	457
Total assets	$ 17,045	$ 15,959	$ 14,794

Goodwill by reportable segment as of December 31, 2016 and 2015 was as follows (in millions):

Regulated electric	$ 1,191
Regulated gas	79
Total	$ 1,270

(21) Subsequent Events

Refer to Note 21 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

SIGNATURES

BERKSHIRE HATHAWAY ENERGY COMPANY

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on this 24th day of February 2017.

BERKSHIRE HATHAWAY ENERGY COMPANY

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

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

Signature	Title	Date
/s/ Gregory E. Abel* Gregory E. Abel	Chairman, President and Chief Executive Officer (principal executive officer)	February 24, 2017
/s/ Patrick J. Goodman* Patrick J. Goodman	Executive Vice President and Chief Financial Officer (principal financial and accounting officer)	February 24, 2017
/s/ Walter Scott, Jr.* Walter Scott, Jr.	Director	February 24, 2017
/s/ Marc D. Hamburg* Marc D. Hamburg	Director	February 24, 2017
/s/ Warren E. Buffett* Warren E. Buffett	Director	February 24, 2017
*By: /s/ Natalie L. Hocken Natalie L. Hocken	Attorney-in-Fact	February 24, 2017

SIGNATURES

PACIFICORP

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on this 24th day of February 2017.

PACIFICORP

/s/ Nikki L. Kobliha

Nikki L. Kobliha
Director, Vice President, Chief Financial Officer, and Treasurer
(principal financial and accounting officer)

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

Signature	Title	Date
/s/ Gregory E. Abel Gregory E. Abel	Chairman of the Board of Directors and Chief Executive Officer (principal executive officer)	February 24, 2017
/s/ Nikki L. Kobliha Nikki L. Kobliha	Director, Vice President, Chief Financial Officer, and Treasurer (principal financial and accounting officer)	February 24, 2017
/s/ Stefan A. Bird Stefan A. Bird	Director	February 24, 2017
/s/ Cindy A. Crane Cindy A. Crane	Director	February 24, 2017
/s/ Patrick J. Goodman Patrick J. Goodman	Director	February 24, 2017
/s/ Natalie L. Hocken Natalie L. Hocken	Director	February 24, 2017

SIGNATURES

MIDAMERICAN ENERGY COMPANY

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on this 24th day of February 2017.

MIDAMERICAN ENERGY COMPANY

/s/ William J. Fehrman
William J. Fehrman
President and Chief Executive Officer
(principal executive officer)

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

Signatures	Title	Date
/s/William J. Fehrman William J. Fehrman	President, Chief Executive Officer and Director (principal executive officer)	February 24, 2017
/s/Thomas B. Specketer Thomas B. Specketer	Vice President, Chief Financial Officer and Director (principal financial and accounting officer)	February 24, 2017
/s/Robert B. Berntsen Robert B. Berntsen	Director	February 24, 2017

SIGNATURES

MIDAMERICAN FUNDING, LLC

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on this 24th day of February 2017.

MIDAMERICAN FUNDING, LLC

/s/ William J. Fehrman
William J Fehrman
President
(principal executive officer)

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

Signatures	Title	Date
/s/William J. Fehrman William J. Fehrman	President and Manager (principal executive officer)	February 24, 2017
/s/Thomas B. Specketer Thomas B. Specketer	Vice President and Controller (principal financial and accounting officer)	February 24, 2017
/s/Patrick J. Goodman Patrick J. Goodman	Manager	February 24, 2017
/s/Sandra Hatfield Clubb Sandra Hatfield Clubb	Manager	February 24, 2017
/s/Natalie L. Hocken Natalie L. Hocken	Manager	February 24, 2017

SIGNATURES

NEVADA POWER COMPANY

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on this 24th day of February 2017.

NEVADA POWER COMPANY

/s/ Paul J. Caudill

Paul J. Caudill
President and Chief Executive Officer
(principal executive officer)

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

Signature	Title	Date
/s/ Paul J. Caudill Paul J. Caudill	President and Chief Executive Officer (principal executive officer)	February 24, 2017
/s/ E. Kevin Bethel E. Kevin Bethel	Senior Vice President, Chief Financial Officer and Director (principal financial and accounting officer)	February 24, 2017
/s/ Douglas A. Cannon Douglas A. Cannon	Director	February 24, 2017
/s/ Patrick S. Egan Patrick S. Egan	Director	February 24, 2017
/s/ Kevin C. Geraghty Kevin C. Geraghty	Director	February 24, 2017
/s/ Francis P. Gonzales Francis P. Gonzales	Director	February 24, 2017
/s/ John C. Owens John C. Owens	Director	February 24, 2017
/s/ Shawn M. Elicegui Shawn M. Elicegui	Director	February 24, 2017

SIGNATURES

SIERRA PACIFIC POWER COMPANY

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on this 24th day of February 2017.

SIERRA PACIFIC POWER COMPANY

/s/ Paul J. Caudill
Paul J. Caudill
President and Chief Executive Officer
(principal executive officer)

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

Signature	Title	Date
/s/ Paul J. Caudill Paul J. Caudill	President and Chief Executive Officer (principal executive officer)	February 24, 2017
/s/ E. Kevin Bethel E. Kevin Bethel	Senior Vice President, Chief Financial Officer and Director (principal financial and accounting officer)	February 24, 2017
/s/ Douglas A. Cannon Douglas A. Cannon	Director	February 24, 2017
/s/ Patrick S. Egan Patrick S. Egan	Director	February 24, 2017
/s/ Kevin C. Geraghty Kevin C. Geraghty	Director	February 24, 2017
/s/ Francis P. Gonzales Francis P. Gonzales	Director	February 24, 2017
/s/ John C. Owens John C. Owens	Director	February 24, 2017
/s/ Shawn M. Elicegui Shawn M. Elicegui	Director	February 24, 2017

SUPPLEMENTAL INFORMATION TO BE FURNISHED WITH REPORTS FILED PURSUANT TO SECTION 15(D) OF THE ACT BY REGISTRANTS WHICH HAVE NOT REGISTERED SECURITIES PURSUANT TO SECTION 12 OF THE ACT

No annual report to security holders covering each respective Registrant's last fiscal year or proxy material has been sent to security holders.

EXHIBIT INDEX

BERKSHIRE HATHAWAY ENERGY

3.1	Second Amended and Restated Articles of Incorporation of MidAmerican Energy Holdings Company effective March 2, 2006 (incorporated by reference to Exhibit 3.1 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2005).
3.2	Articles of Amendment to the Second Amended and Restated Articles of Incorporation of MidAmerican Energy Holdings Company effective April 30, 2014 (incorporated by reference to Exhibit 3.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2014).
3.3	Amended and Restated Bylaws of Berkshire Hathaway Energy Company (incorporated by reference to Exhibit 3.2 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2005).
4.1	Shareholders Agreement, dated as of March 14, 2000 (incorporated by reference to Exhibit 4.19 to the Berkshire Hathaway Energy Company Registration Statement No. 333-101699 dated December 6, 2002).
4.2	Amendment No. 1 to Shareholders Agreement, dated December 7, 2005 (incorporated by reference to Exhibit 4.17 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2005).
4.3	Indenture, dated as of November 12, 2014, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the Junior Subordinated Debentures due 2044 (including form of junior subordinated debenture) (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated December 1, 2014).
4.4	Indenture, dated as of October 4, 2002, by and between MidAmerican Energy Holdings Company and The Bank of New York, Trustee (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Registration Statement No. 333-101699 dated December 6, 2002).
4.5	Fourth Supplemental Indenture, dated as of March 24, 2006, by and between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., Trustee, relating to the 6.125% Senior Bonds due 2036 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated March 28, 2006).
4.6	Fifth Supplemental Indenture, dated as of May 11, 2007, by and between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., Trustee, relating to the 5.95% Senior Bonds due 2037 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated May 11, 2007).
4.7	Sixth Supplemental Indenture, dated as of August 28, 2007, by and between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., Trustee, relating to the 6.50% Senior Bonds due 2037 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated August 28, 2007).
4.8	Seventh Supplemental Indenture, dated as of March 28, 2008, by and between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., as Trustee, relating to the 5.75% Senior Notes due 2018 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated March 28, 2008).
4.9	Ninth Supplemental Indenture, dated as of November 8, 2013, by and between MidAmerican Energy Holdings Company and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 1.100% Senior Notes due 2017, the 2.000% Senior Notes due 2018, the 3.750% Senior Notes due 2023 and the 5.150% Senior Notes due 2043 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated November 8, 2013).
4.10	Tenth Supplemental Indenture, dated as December 4, 2014, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 2.40% Senior Notes due 2020, the 3.50% Senior Notes due 2025 and the 4.50% Senior Notes due 2045 (incorporated by reference to Exhibit 4.8 to the Berkshire Hathaway Energy Company Registration Statement No. 333-200928 dated December 12, 2014).

Exhibit No.	Description
4.11	Indenture, dated as of October 15, 1997, by and between MidAmerican Energy Holdings Company and IBJ Schroder Bank & Trust Company, Trustee (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated October 23, 1997).
4.12	Form of Second Supplemental Indenture, dated as of September 22, 1998 by and between MidAmerican Energy Holdings Company and IBJ Schroder Bank & Trust Company, Trustee, relating to the 8.48% Senior Notes in the principal amount of $475,000,000 due 2028 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated September 17, 1998).
4.13	Indenture, dated May 1, 2000, between NV Energy, Inc. (under its former name, Sierra Pacific Resources) and The Bank of New York, relating to the issuance of debt securities (incorporated by reference to Exhibit 4.1 to the NV Energy, Inc. Current Report on Form 8-K dated May 22, 2000).
4.14	Form of Officers' Certificate establishing the terms of NV Energy, Inc.'s 6.25% Senior Notes due 2020 (incorporated by reference to Exhibit 4.1 to the NV Energy, Inc. Current Report on Form 8-K dated November 19, 2010).
4.15	Trust Deed, dated December 15, 1997 among CE Electric UK Funding Company, AMBAC Insurance UK Limited and The Law Debenture Trust Corporation, p.l.c., Trustee (incorporated by reference to Exhibit 99.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated March 30, 2004).
4.16	Insurance and Indemnity Agreement, dated December 15, 1997 by and between CE Electric UK Funding Company and AMBAC Insurance UK Limited (incorporated by reference to Exhibit 99.2 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated March 30, 2004).
4.17	Supplemental Agreement to Insurance and Indemnity Agreement, dated September 19, 2001, by and between CE Electric UK Funding Company and AMBAC Insurance UK Limited (incorporated by reference to Exhibit 99.3 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated March 30, 2004).
4.18	Trust Indenture, dated as of September 10, 1999, by and between Cordova Funding Corporation and Chase Manhattan Bank and Trust Company, National Association, Trustee, relating to the $225,000,000 in principal amount of the 8.75% Senior Secured Bonds due 2019 (incorporated by reference to Exhibit 10.71 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.19	Trust Deed, dated as of February 4, 1998 among Yorkshire Power Finance Limited, Yorkshire Power Group Limited and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 7.25% Guaranteed Bonds due 2028 (incorporated by reference to Exhibit 10.74 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.20	First Supplemental Trust Deed, dated as of October 1, 2001, among Yorkshire Power Finance Limited, Yorkshire Power Group Limited and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 7.25% Guaranteed Bonds due 2028 (incorporated by reference to Exhibit 10.75 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.21	Third Supplemental Trust Deed, dated as of October 1, 2001, among Yorkshire Electricity Distribution plc, Yorkshire Electricity Group plc and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 9.25% Bonds due 2020 (incorporated by reference to Exhibit 10.76 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.22	First Supplemental Trust Deed, dated as of September 27, 2001, among Northern Electric Finance plc, Northern Electric plc, Northern Electric Distribution Limited and The Law Debenture Trust Corporation p.l.c., Trustee, relating to the £100,000,000 in principal amount of the 8.875% Guaranteed Bonds due 2020 (incorporated by reference to Exhibit 10.81 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.23	Trust Deed, dated as of January 17, 1995, by and between Yorkshire Electricity Group plc and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 9 1/4% Bonds due 2020 (incorporated by reference to Exhibit 10.83 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).

Exhibit No.	Description
4.24	Master Trust Deed, dated as of October 16, 1995, by and between Northern Electric Finance plc, Northern Electric plc and The Law Debenture Trust Corporation p.l.c., Trustee, relating to the £100,000,000 in principal amount of the 8.875% Guaranteed Bonds due 2020 (incorporated by reference to Exhibit 10.70 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2004).
4.25	Trust Deed dated May 5, 2005 among Northern Electric Finance plc, Northern Electric Distribution Limited, Ambac Assurance UK Limited and HSBC Trustee (C.I.) Limited (incorporated by reference to Exhibit 99.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.26	Reimbursement and Indemnity Agreement, dated May 5, 2005 among Northern Electric Finance plc, Northern Electric Distribution Limited and Ambac Assurance UK Limited (incorporated by reference to Exhibit 99.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.27	Trust Deed, dated May 5, 2005 among Yorkshire Electricity Distribution plc, Ambac Assurance UK Limited and HSBC Trustee (C.I.) Limited (incorporated by reference to Exhibit 99.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.28	Reimbursement and Indemnity Agreement, dated May 5, 2005 between Yorkshire Electricity Distribution plc and Ambac Assurance UK Limited (incorporated by reference to Exhibit 99.4 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.29	Supplemental Trust Deed, dated May 5, 2005 among CE Electric UK Funding Company, Ambac Assurance UK Limited and The Law Debenture Trust Corporation plc (incorporated by reference to Exhibit 99.5 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.30	Second Supplemental Agreement to Insurance and Indemnity Agreement, dated May 5, 2005 by and between CE Electric UK Funding Company and Ambac Assurance UK Limited (incorporated by reference to Exhibit 99.6 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.31	£119,000,000 Finance Contract, dated July 2, 2010, by and between Northern Electric Distribution Limited and the European Investment Bank (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2010).
4.32	Guarantee and Indemnity Agreement, dated July 2, 2010, by and between CE Electric UK Funding Company and the European Investment Bank (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2010).
4.33	£151,000,000 Finance Contract, dated July 2, 2010, by and between Yorkshire Electricity Distribution plc and the European Investment Bank (incorporated by reference to Exhibit 4.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2010).
4.34	Guarantee and Indemnity Agreement, dated July 2, 2010, by and between CE Electric UK Funding Company and the European Investment Bank (incorporated by reference to Exhibit 4.4 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2010).
4.35	Trust Deed, dated as of July 5, 2012, among Northern Powergrid (Yorkshire) plc and HSBC Corporate Trustee Company (UK) Limited, relating to the £150,000,000 in principal amount of the 4.375% Bonds due 2032 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2012).
4.36	Trust Deed, dated as of April 1, 2015, among Northern Powergrid (Yorkshire) plc and HSBC Corporate Trustee Company (UK) Limited, relating to the £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).
4.37	£120,000,000 Finance Contract, dated December 2, 2015, by and between Northern Powergrid (Northeast) Ltd and the European Investment Bank (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).

Exhibit No.	Description
4.38	Guarantee and Indemnity Agreement, dated December 8, 2015, by and between Northern Powergrid Holdings Company and the European Investment Bank (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
4.39	£130,000,000 Finance Contract, dated December 2, 2015, by and between Northern Powergrid (Yorkshire) plc and the European Investment Bank (incorporated by reference to Exhibit 4.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
4.40	Guarantee and Indemnity Agreement, dated December 8, 2015, by and between Northern Powergrid Holdings Company and the European Investment Bank (incorporated by reference to Exhibit 4.4 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
4.41	Deed of Amendment and Consent, dated March 1, 2016, by and between Northern Powergrid Holdings Company, Northern Powergrid (Yorkshire) plc and the European Investment Bank (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, 2016).
4.42	Fiscal Agency Agreement, dated as of July 15, 2008, by and between Northern Natural Gas Company and The Bank New York Mellon Trust Company, National Association, Fiscal Agent, relating to the $200,000,000 in principal amount of the 5.75% Senior Notes due 2018 (incorporated by reference to Exhibit 4.32 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2008).
4.43	Fiscal Agency Agreement, dated as of April 20, 2011, by and between Northern Natural Gas Company and The Bank of New York Mellon Trust Company, N.A., Fiscal Agent, relating to the $200,000,000 in principal amount of the 4.25% Senior Notes due 2021 (incorporated by reference to Exhibit 4.27 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2011).
4.44	Fiscal Agency Agreement, dated February 12, 2007, by and between Northern Natural Gas Company and The Bank of New York Trust Company, N.A., Fiscal Agent, relating to the $150,000,000 in principal amount of the 5.80% Senior Bonds due 2037 (incorporated by reference to Exhibit 99.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated February 12, 2007).
4.45	Fiscal Agency Agreement, dated August 27, 2012, by and between Northern Natural Gas Company and The Bank of New York Mellon Trust Company, N.A., Fiscal Agent, relating to the $250,000,000 in principal amount of the 4.10% Senior Bonds due 2042 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2012).
4.46	Trust Indenture, dated as of August 13, 2001, among Kern River Funding Corporation, Kern River Gas Transmission Company and JP Morgan Chase Bank, Trustee (incorporated by reference to Exhibit 10.48 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2003).
4.47	Third Supplemental Indenture, dated as of May 1, 2003, among Kern River Funding Corporation, Kern River Gas Transmission Company and JPMorgan Chase Bank, Trustee, relating to the $836,000,000 in principal amount of the 4.893% Senior Notes due 2018 (incorporated by reference to Exhibit 10.49 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2003).
4.48	Master Trust Indenture, dated November 21, 2005, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.94 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.49	Third Supplemental Indenture, dated December 15, 2010, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.96 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).

Exhibit No.	Description
4.50	Series 12-1 Supplemental Indenture, dated June 5, 2012, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.97 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.51	Series 13-1 Supplemental Indenture, dated April 9, 2013, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.98 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.52	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 amount 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).
4.53	2016 Supplemental Indenture, dated December 9, 2016, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada.
4.54	Amended and Restated Master Trust Indenture, dated April 28, 2003, by and between AltaLink, L.P., AltaLink Management Ltd. and BMO Trust Company (incorporated by reference to Exhibit 4.99 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.55	Seventh Supplemental Indenture, dated April 28, 2003, by and between AltaLink, L.P., AltaLink Management Ltd. and BMO Trust Company (incorporated by reference to Exhibit 4.100 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.56	Ninth Supplemental Indenture, dated May 9, 2006, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.101 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.57	Tenth Supplemental Indenture, dated May 21, 2008, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.102 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.58	Twelfth Supplemental Indenture, dated August 18, 2010, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.103 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.59	Sixteenth Supplemental Indenture, dated November 15, 2012, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.104 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.60	Seventeenth Supplemental Indenture, dated May 22, 2013, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.105 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.61	Eighteenth Supplemental Indenture, dated October 24, 2014, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.106 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.62	Nineteenth Supplemental Indenture, dated October 24, 2014, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.107 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).

Exhibit No.	Description
4.63	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 amount 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).
4.64	Indenture, dated as of February 24, 2012, by and between Topaz Solar Farms LLC and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the $850,000,000 in principal amount of the 5.75% Series A Senior Secured Notes due 2039 (incorporated by reference to Exhibit 4.56 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2011).
4.65	First Supplemental Indenture, dated as of April 15, 2013, between Topaz Solar Farms LLC, as Issuer, and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the $250,000,000 in principal amount of the 4.875% Series B Senior Secured Notes due 2039 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2013).
4.66	Indenture, dated as of June 27, 2013, between Solar Star Funding, LLC, as Issuer, and Wells Fargo Bank, National Association, as Trustee, relating to the $1,000,000,000 in principal amount of the 5.375% Series A Senior Secured Notes due 2035 (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2013).
4.67	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 amount 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).
4.68	Indenture, dated as of March 2, 1999, by and between CE Generation, LLC and Chase Manhattan Bank and Trust Company, National Association (incorporated by reference to Exhibit 4.1 to the CE Generation, LLC Registration Statement No. 333-89521 dated October 22, 1999).
4.69	First Supplemental Indenture, dated as of February 4, 2000, by and between CE Generation, LLC and Chase Manhattan Bank and Trust Company, National Association (incorporated by reference to Exhibit 4.2 to the CE Generation, LLC Registration Statement No. 333-89521 dated October 22, 1999).
4.70	Second Supplemental Indenture, dated as of March 6, 2000, by and between CE Generation, LLC and Chase Manhattan Bank and Trust Company, National Association (incorporated by reference to Exhibit 4.89 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.71	Indenture, dated July 21, 1995, by and between Salton Sea Funding Corporation and Chase Manhattan Bank and Trust Company, National Association (incorporated by reference to Exhibit 4.1(a) to the Salton Sea Funding Corporation Registration Statement No. 333-95538 dated January 10, 1996).
4.72	Fourth Supplemental Indenture, dated October 13, 1998, by and between Salton Sea Funding Corporation and Chase Manhattan Bank and Trust Company, National Association (incorporated by reference to Exhibit 4.1(e) to the Salton Sea Funding Corporation Annual Report on Form 10-K/A for the year ended December 31, 1998).
4.73	Fifth Supplemental Indenture, dated February 16, 1999, by and between Salton Sea Funding Corporation and Chase Manhattan Bank and Trust Company, National Association (incorporated by reference to Exhibit 4.1(f) to the Salton Sea Funding Corporation Registration Statement No. 333-79581 dated June 29, 1999).
4.74	Sixth Supplemental Indenture, dated June 29, 1999, by and between Salton Sea Funding Corporation and Chase Manhattan Bank and Trust Company, National Association (incorporated by reference to Exhibit 4.1(g) to the Salton Sea Funding Corporation Registration Statement No. 333-79581 dated June 29, 1999).

Exhibit No.	Description
10.1	$2,000,000,000 Credit Agreement, dated as of June 30, 2016, among Berkshire Hathaway Energy Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, MUFG Union Bank, N.A., as Administrative Agent, and the LC Issuing Banks (incorporated by reference to Exhibit 10.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
10.2	Amended and Restated £150,000,000 Facility Agreement, dated April 30, 2015, among Northern Powergrid Holdings Company, as Guarantor and Borrower, Northern Powergrid (Yorkshire) plc and Northern Powergrid (Northeast) Limited as Borrowers, and Abbey National Treasury Services plc, Lloyds Bank plc and The Royal Bank of Scotland plc, as Original Lenders (incorporated by reference to Exhibit 10.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
10.3	Amended and Restated Credit Agreement, dated as of July 30, 2015, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, The Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
10.4	First Amending Agreement to Amended and Restated Credit Agreement, dated as of November 20, 2015, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, The Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.4 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
10.5	Second Amending Agreement to Amended and Restated Credit Agreement, dated as of December 14, 2015, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, The Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.5 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
10.6	Third Amending Agreement to Amended and Restated Credit Agreement, dated as of July 8, 2016, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, The Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.6 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
10.7	Fourth Amending Agreement to Amended and Restated Credit Agreement, dated as of December 15, 2016, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, The Royal Bank of Canada, as administrative agent, and Lenders.
10.8	Credit Agreement, dated as of December 9, 2016, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, The Royal Bank of Canada, as administrative agent, and Lenders.
10.9	Fourth Amended and Restated Credit Agreement, dated as of December 17, 2015, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.8 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
10.10	First Amending Agreement to Fourth Amended and Restated Credit Agreement, dated as of December 15, 2016, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders.
10.11	Third Amended and Restated Credit Agreement, dated as of December 17, 2015, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.7 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
10.12	First Amending Agreement to Third Amended and Restated Credit Agreement, dated as of December 15, 2016, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders.
10.13*	Summary of Key Terms of Compensation Arrangements with Berkshire Hathaway Energy Company Named Executive Officers and Directors.

Exhibit No.	Description
10.14*	Amended and Restated Employment Agreement, dated February 25, 2008, by and between MidAmerican Energy Holdings Company and Gregory E. Abel (incorporated by reference to Exhibit 10.3 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2007).
10.15*	Amended and Restated Employment Agreement, dated February 25, 2008, by and between MidAmerican Energy Holdings Company and Patrick J. Goodman (incorporated by reference to Exhibit 10.5 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2007).
10.16*	CalEnergy Company, Inc. Voluntary Deferred Compensation Plan, effective December 1, 1997, First Amendment, dated as of August 17, 1999, and Second Amendment effective March 14, 2000 (incorporated by reference to Exhibit 10.50 to the MidAmerican Energy Holdings Company Registration Statement No. 333-101699 dated December 6, 2002).
10.17*	Berkshire Hathaway Energy Company Executive Voluntary Deferred Compensation Plan restated effective as of January 1, 2007 (incorporated by reference to Exhibit 10.9 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2007).
10.18*	MidAmerican Energy Company First Amended and Restated Supplemental Retirement Plan for Designated Officers dated as of May 10, 1999 amended on February 25, 2008 to be effective as of January 1, 2005 (incorporated by reference to Exhibit 10.10 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2007).
10.19*	Berkshire Hathaway Energy Company Long-Term Incentive Partnership Plan as Amended and Restated January 1, 2014 (incorporated by reference to Exhibit 10.9 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
14.1	Berkshire Hathaway Energy Company Code of Ethics For Chief Executive Officer, Chief Financial Officer and Other Covered Officers (incorporated by reference to Exhibit 14.1 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2015).
21.1	Subsidiaries of the Registrant.
23.1	Consent of Deloitte & Touche LLP.
24.1	Power of Attorney.
31.1	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
PACIFICORP	
3.4	Third Restated Articles of Incorporation of PacifiCorp (incorporated by reference to Exhibit (3)a to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 1996).
3.5	Bylaws of PacifiCorp, as amended May 23, 2005 (incorporated by reference to Exhibit 3.2 to the PacifiCorp Annual Report on Form 10-K for the year ended March 31, 2005).
10.20*	Summary of Key Terms of Compensation Arrangements with PacifiCorp's Named Executive Officers and Directors.
10.21*	PacifiCorp Executive Voluntary Deferred Compensation Plan (incorporated by reference to Exhibit 10.3 to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 2007).
10.22*	Supplemental Executive Retirement Plan (incorporated by reference to Exhibit 10.7 to the PacifiCorp Annual Report on Form 10-K for the year ended March 31, 2005).
10.23*	Amendment No. 10 to PacifiCorp Supplemental Executive Retirement Plan dated June 2, 2006 (incorporated by reference to Exhibit 10.5 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).

Exhibit No.	Description
10.24*	Amendment No. 11 to PacifiCorp Supplemental Executive Retirement Plan dated June 2, 2006 (incorporated by reference to Exhibit 10.6 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.25*	Amendment No. 1 to the PacifiCorp Executive Voluntary Deferred Compensation Plan dated October 28, 2008 (incorporated by reference to Exhibit 10.10 to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 2009).
10.26*	Amendment No. 2 to the PacifiCorp Executive Voluntary Deferred Compensation Plan dated October 16, 2012 (incorporated by reference to Exhibit 10.11 to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 2012).
10.27*	PacifiCorp Long-Term Incentive Partnership Plan effective January 1, 2014 (incorporated by reference to Exhibit 10.10 to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 2014).
12.1	Statements of Computation of Ratio of Earnings to Fixed Charges.
12.2	Statements of Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends.
14.2	Code of Ethics (incorporated by reference to Exhibit 14.1 to the PacifiCorp Transition Report on Form 10-K for the nine-month period ended December 31, 2006).
23.2	Consent of Deloitte & Touche LLP.
31.3	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.4	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.3	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.4	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit No.	Description

BERKSHIRE HATHAWAY ENERGY AND PACIFICORP

4.75 Mortgage and Deed of Trust dated as of January 9, 1989, between PacifiCorp and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, incorporated by reference to Exhibit 4-E to the PacifiCorp Form 8-B, as supplemented and modified by 28 Supplemental Indentures, each incorporated by reference, as follows:

Exhibit Number	PacifiCorp File Type	File Date
(4)(b)	SE	November 2, 1989
(4)(a)	8-K	January 9, 1990
4(a)	8-K	September 11, 1991
4(a)	8-K	January 7, 1992
4(a)	10-Q	Quarter ended March 31, 1992
4(a)	10-Q	Quarter ended September 30, 1992
4(a)	8-K	April 1, 1993
4(a)	10-Q	Quarter ended September 30, 1993
(4)b	10-Q	Quarter ended June 30, 1994
(4)b	10-K	Year ended December 31, 1994
(4)b	10-K	Year ended December 31, 1995
(4)b	10-K	Year ended December 31, 1996
(4)b	10-K	Year ended December 31, 1998
99(a)	8-K	November 21, 2001
4.1	10-Q	Quarter ended June 30, 2003
99	8-K	September 8, 2003
4	8-K	August 24, 2004
4	8-K	June 13, 2005
4.2	8-K	August 14, 2006
4	8-K	March 14, 2007
4.1	8-K	October 3, 2007
4.1	8-K	July 17, 2008
4.1	8-K	January 8, 2009
4.1	8-K	May 12, 2011
4.1	8-K	January 6, 2012
4.1	8-K	June 6, 2013
4.1	8-K	March 13, 2014
4.1	8-K	June 19, 2015

10.28 $400,000,000 Credit Agreement, dated as of June 30, 2016, among PacifiCorp, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, JPMorgan Chase Bank, N.A., as Administrative Agent, and the LC Issuing Banks (incorporated by reference to Exhibit 10.9 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).

10.29 $600,000,000 Credit Agreement, dated as of March 27, 2013, among PacifiCorp, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, JPMorgan Chase Bank, N.A., as Administrative Agent and Swingline Lender, and the LC Issuing Banks (incorporated by reference to Exhibit 10.1 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended March 31, 2013).

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

Exhibit No.	Description
MIDAMERICAN ENERGY	
3.6	Restated Articles of Incorporation of MidAmerican Energy Company, as amended October 27, 1998. (incorporated by reference to Exhibit 3.3 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 1998).
3.7	Restated Bylaws of MidAmerican Energy Company, as amended July 24, 1996. (incorporated by reference to Exhibit 3.1 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 1996).
14.3	Code of Ethics for Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. (incorporated by reference to Exhibit 14.1 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2003).
23.3	Consent of Deloitte & Touche LLP.
31.5	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.6	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.5	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.6	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
MIDAMERICAN FUNDING	
3.8	Articles of Organization of MidAmerican Funding, LLC (incorporated by reference to Exhibit 3.1 to the MidAmerican Funding, LLC Registration Statement No. 333-90553 dated November 8, 1999).
3.9	Operating Agreement of MidAmerican Funding, LLC (incorporated by reference to Exhibit 3.2 to the MidAmerican Funding, LLC Registration Statement No. 333-90553 dated November 8, 1999).
3.10	Amendment No. 1 to the Operating Agreement of MidAmerican Funding, LLC dated as of February 9, 2010 (incorporated by reference to Exhibit 3.3 to the MidAmerican Funding, LLC Annual Report on Form 10-K for the year ended December 31, 2010).
14.4	Code of Ethics for Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer (incorporated by reference to Exhibit 14.2 to the MidAmerican Funding, LLC Annual Report on Form 10-K for the year ended December 31, 2003).
31.7	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.8	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.7	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.8	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
BERKSHIRE HATHAWAY ENERGY, MIDAMERICAN ENERGY AND MIDAMERICAN FUNDING	
4.76	Form of Indenture, by and between MidAmerican Energy Company and The Bank of New York, Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Registration Statement No. 333-59760 dated January 31, 2002).
4.77	First Supplemental Indenture, dated as of February 8, 2002, by and between MidAmerican Energy Company and The Bank of New York, Trustee (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2004).
4.78	Fourth Supplemental Indenture, dated November 1, 2005, by and between MidAmerican Energy Company and The Bank of New York Trust Company, NA, Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2005).
4.79	Indenture, dated as of October 1, 2006, by and between MidAmerican Energy Company and The Bank of New York Trust Company, N.A., Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).

Exhibit No.	Description
4.80	First Supplemental Indenture, dated as of October 6, 2006, by and between MidAmerican Energy Company and The Bank of New York Trust Company, N.A., Trustee relating to the 5.80% Notes due 2036 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
4.81	Second Supplemental Indenture, dated June 29, 2007, by and between MidAmerican Energy Company and The Bank of New York Trust Company, N.A., Trustee relating to the 5.95% Notes due 2017 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated June 29, 2007).
4.82	Third Supplemental Indenture, dated March 25, 2008, by and between MidAmerican Energy Company and The Bank of New York Trust Company, Trustee, relating to the 5.30% Notes due 2018 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated March 25, 2008).
4.83	Indenture, dated as of September 9, 2013, between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated September 13, 2013).
4.84	First Supplemental Indenture, dated as of September 19, 2013, between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated September 19, 2013).
4.85	Specimen of 2.40% First Mortgage Bonds due 2019 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated September 19, 2013).
4.86	Specimen of 3.70% First Mortgage Bonds due 2023 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated September 19, 2013).
4.87	Specimen of 4.80% First Mortgage Bonds due 2043 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated September 19, 2013).
4.88	Amendment No. 1 to the First Supplemental Indenture, dated as of April 3, 2014, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated April 3, 2014).
4.89	Second Supplemental Indenture, dated as of April 3, 2014, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated April 3, 2014).
4.90	Specimen of 3.50% First Mortgage Bonds due 2024 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated April 3, 2014).
4.91	Specimen of 4.40% First Mortgage Bonds due 2044 (incorporated by reference to Exhibit 4.5 to the MidAmerican Energy Company Current Report on Form 8-K dated April 3, 2014).
4.92	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 the 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).
4.93	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 the 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).
4.94	Specimen of 3.50% First Mortgage Bonds due 2024 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2015).
4.95	Specimen of 4.25% First Mortgage Bonds due 2046 (incorporated by reference to Exhibit 4.5 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2015).

Exhibit No.	Description
4.96	Fourth Supplemental Indenture, dated as of December 8, 2016, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013.
4.97	Fifth Supplemental Indenture, dated as of February 1, 2017, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the 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 February 1, 2017).
4.98	Specimen of 3.10% First Mortgage Bonds due 2027 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated February 1, 2017).
4.99	Specimen of 3.95% First Mortgage Bonds due 2047 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated February 1, 2017).
4.100	Mortgage, Security Agreement, Fixture Filing and Financing Statement, dated as of September 9, 2013, from MidAmerican Energy Company to The Bank of New York Mellon Trust Company, N.A., as collateral trustee (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated September 13, 2013).
4.101	Intercreditor and Collateral Trust Agreement, dated as of September 9, 2013, among MidAmerican Energy Company, The Bank of New York Mellon Trust Company, N.A., as trustee, and The Bank of New York Mellon Trust Company, N.A., as collateral trustee (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated September 13, 2013).
4.102	Form of Indenture, between MidAmerican Energy Company and the Trustee, (Senior Unsecured Debt Securities) (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Registration Statement No. 333-192077 dated November 4, 2013).
4.103	Form of Indenture, between MidAmerican Energy Company and the Trustee, (Subordinated Unsecured Debt Securities) (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Registration Statement No. 333-192077 dated November 4, 2013).
10.30	$600,000,000 Credit Agreement, dated as of March 27, 2013, among MidAmerican Energy Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, JPMorgan Chase Bank, N.A., as Administrative Agent and Swingline Lender, and the LC Issuing Banks (incorporated by reference to Exhibit 10.1 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2013).

BERKSHIRE HATHAWAY ENERGY AND MIDAMERICAN FUNDING

4.104	Indenture and First Supplemental Indenture, dated March 11, 1999, by and between MidAmerican Funding, LLC and IBJ Whitehall Bank & Trust Company, Trustee, relating to the $325 million Senior Bonds (incorporated by reference to Exhibits 4.1 and 4.2 to the MidAmerican Funding, LLC Registration Statement No. 333-905333 dated November 8, 1999).

NEVADA POWER

3.11	Restated Articles of Incorporation of Nevada Power Company, dated July 28, 1999 (incorporated by reference to Exhibit 3(B) to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 1999).
3.12	Amended and Restated By-Laws of Nevada Power Company dated July 28, 1999 (incorporated by reference to Exhibit 3(C) to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 1999).
10.31	Transmission Use and Capacity Exchange Agreement between Nevada Power Company, Sierra Pacific Power Company and Great Basin Transmission, LLC dated August 20, 2010 (incorporated by reference to Exhibit 10.1 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2010).

Exhibit No.	Description
10.32	Financing Agreement between Clark County, Nevada and Nevada Power Company, dated August 1, 2006 (relating to Clark County, Nevada $39,500,000 Pollution Control Refund Revenue Bonds Series 2006) (incorporated by reference to Exhibit 10.1 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
10.33	Financing Agreement between Coconino County, Arizona Pollution Control Corporation and Nevada Power Company, dated August 1, 2006 (relating to Coconino County, Arizona $13,000,000 Pollution Control Corporation Refunding Revenue Bonds Series 2006B) (incorporated by reference to Exhibit 10.3 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
10.34	Financing Agreement between Coconino County, Arizona Pollution Control Corporation and Nevada Power Company, dated August 1, 2006 (relating to Coconino County, Arizona $40,000,000 Pollution Control Corporation Refunding Revenue Bonds Series 2006A) (incorporated by reference to Exhibit 10.2 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
12.3	Computation of Ratios of Earnings to Fixed Charges.
14.5	Code of Ethics for Chief Executive Officer, Chief Financial Officer and Other Covered Officers (incorporated by reference to Exhibit 14.1 to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 2013).
23.4	Consent of Deloitte & Touche LLP.
31.9	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.10	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.9	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.10	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

BERKSHIRE HATHAWAY ENERGY AND NEVADA POWER

4.105	General and Refunding Mortgage Indenture, dated May 1, 2001, between Nevada Power Company and The Bank of New York, as Trustee (incorporated by reference to Exhibit 4.1(a) to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
4.106	First Supplemental Indenture, dated as of May 1, 2001 (incorporated by reference to Exhibit 4.1(b) to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
4.107	Second Supplemental Indenture, dated as of October 1, 2001 (incorporated by reference to Exhibit 4(A) to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 2001).
4.108	Officer's Certificate establishing the terms of Nevada Power Company's 6.650% General and Refunding Mortgage Notes, Series N, due 2036 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Form 10-Q for the quarter ended March 31, 2006).
4.109	Officer's Certificate establishing the terms of Nevada Power Company's 6.50% General and Refunding Mortgage Notes, Series O, due 2018 (incorporated by reference to Exhibit 4.7 to the Nevada Power Company Registration Statement No. 333-134801 dated June 7, 2006).
4.110	Officer's Certificate establishing the terms of Nevada Power Company's 6.750% General and Refunding Mortgage Notes, Series R, due 2037 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated June 27, 2007).
4.111	Officer's Certificate establishing the terms of Nevada Power Company's 6.50% General and Refunding Mortgage Notes, Series S, due 2018 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated July 28, 2008).
4.112	Officer's Certificate establishing the terms of Nevada Power Company d/b/a NV Energy's 7.125% General and Refunding Mortgage Notes, Series V, due 2019 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated February 26, 2009).

Exhibit No.	Description
4.113	Officer's Certificate establishing the terms of Nevada Power Company d/b/a NV Energy's 5.375% General and Refunding Mortgage Notes, Series X, due 2040 (incorporated by reference to Exhibit 4.1 to Nevada Power Company Current Report on Form 8-K dated September 10, 2010).
4.114	Officer's Certificate establishing the terms of Nevada Power Company d/b/a NV Energy's 5.45% General and Refunding Mortgage Notes, Series Y, due 2041 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated May 10, 2011).
10.35	$400,000,000 Amended and Restated Credit Agreement, dated as of June 27, 2014, among Nevada Power Company, as Borrower, the Initial Lenders, Wells Fargo Bank, National Association, as Administrative Agent and Swingline Lender, and the LC Issuing Banks (incorporated by reference to Exhibit 10.1 to the Nevada Power Company Current Report on Form 8-K dated June 27, 2014).
SIERRA PACIFIC	
3.13	Restated Articles of Incorporation of Sierra Pacific Power Company, dated October 25, 2006 (incorporated by reference to Exhibit 3.1 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for quarter ended September 30, 2006).
3.14	By-Laws of Sierra Pacific Power Company, as amended through November 13, 1996 (incorporated by reference to Exhibit (3)(A) to the Sierra Pacific Power Company Annual Report on Form 10-K for the year ended December 31, 1996).
10.36	Transmission Use and Capacity Exchange Agreement between Nevada Power Company, Sierra Pacific Power Company and Great Basin Transmission, LLC dated August 20, 2010 (incorporated by reference to Exhibit 10.1 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2010).
10.37	Financing Agreement dated May 1, 2016 between Washoe County, Nevada and Sierra Pacific Power Company (relating to Washoe County, Nevada's $80,000,000 Water Facilities Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2016C, 2016D and 2016E (incorporated by reference to Exhibit 4.1 to the Sierra Pacific Power Company Current Report on Form 8-K dated May 24, 2016).
10.38	Financing Agreement dated May 1, 2016 between Washoe County, Nevada and Sierra Pacific Power Company (relating to Washoe County, Nevada's $213,930,000 Gas Facilities Refunding Revenue Bonds, Gas and Water Facilities Refunding Revenue Bonds and Water Facilities Refunding Revenue Bonds (Sierra Pacific Power Company Projects) Series 2016A, 2016B, 2016F and 2016G (incorporated by reference to Exhibit 4.2 to the Sierra Pacific Power Company Current Report on Form 8-K dated May 24, 2016).
10.39	Financing Agreement dated May 1, 2016 between Humboldt County, Nevada and Sierra Pacific Power Company (relating to Humboldt County, Nevada's $49,750,000 Pollution Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2016A and 2016B (incorporated by reference to Exhibit 4.3 to the Sierra Pacific Power Company Current Report on Form 8-K dated May 24, 2016).
12.4	Computation of Ratios of Earnings to Fixed Charges.
14.6	Code of Ethics for Chief Executive Officer, Chief Financial Officer and Other Covered Officers (incorporated by reference to Exhibit 14.1 to the Sierra Pacific Power Company Annual Report on Form 10-K for the year ended December 31, 2013).
31.11	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.12	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.11	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.12	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit No.	Description
	BERKSHIRE HATHAWAY ENERGY AND SIERRA PACIFIC
4.115	General and Refunding Mortgage Indenture, dated as of May 1, 2001, between Sierra Pacific Power Company and The Bank of New York, as Trustee (incorporated by reference to Exhibit 4.2(a) to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
4.116	Second Supplemental Indenture, dated as of October 30, 2006, to subject additional properties of Sierra Pacific Power Company located in the State of California to the lien of the General and Refunding Mortgage Indenture and to correct defects in the original Indenture (incorporated by reference to Exhibit 4(A) to the Sierra Pacific Power Company Annual Report on Form 10-K for the year ended December 31, 2006).
4.117	Officer's Certificate establishing the terms of Sierra Pacific Power Company's 6.750% General and Refunding Mortgage Notes, Series P, due 2037 (incorporated by reference to Exhibit 4.2 to the Sierra Pacific Power Company Current Report on Form 8-K dated June 27, 2007).
4.118	Officer’s Certificate establishing the terms of Sierra Pacific Power Company's 3.375% General and Refunding Mortgage Notes, Series T, due 2023 (incorporated by reference to Exhibit 4.1 to the Sierra Pacific Power Company Current Report on Form 8-K dated August 14, 2013).
4.119	Officer's Certificate establishing the terms of Sierra Pacific Power Company's 2.60% General and Refunding Mortgage Notes, Series U, due 2026 (incorporated by reference to Exhibit 4.1 to the Sierra Pacific Power Company Current Report on Form 8-K dated April 15, 2016).
4.120	Officer’s Certificate establishing the terms of Sierra Pacific Power Company’s General and Refunding Mortgage Notes, Series V (Nos. V-1, V-2 and V-3) (incorporated by reference to Exhibit 4.4 to the Sierra Pacific Power Company Current Report on Form 8-K dated May 24, 2016).
10.40	$250,000,000 Amended and Restated Credit Agreement, dated as of June 27, 2014, among Sierra Pacific Power Company, as Borrower, the Initial Lenders, Wells Fargo Bank, National Association, as Administrative Agent and Swingline Lender, and the LC Issuing Banks (incorporated by reference to Exhibit 10.1 to the Sierra Pacific Power Company Current Report on Form 8-K dated June 27, 2014).
	ALL REGISTRANTS
101	The following financial information from each respective Registrant's Annual Report on Form 10-K for the year ended December 31, 2016 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.

* Management contract or compensatory plan.

Pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K, each Registrant has not filed as an exhibit to this Form 10-K certain instruments with respect to long-term debt not registered in which the total amount of securities authorized thereunder does not exceed 10% of the total assets of the respective Registrant. Each Registrant hereby agrees to furnish a copy of any such instrument to the Commission upon request.

EXHIBIT 12.1

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

	Years Ended December 31,				
	2016	2015	2014	2013	2012
Earnings Available for Fixed Charges:					
Income from continuing operations before income tax expense	$ 1,103	$ 1,023	$ 1,007	$ 979	$ 734
Fixed charges	385	384	384	385	385
Total earnings available for fixed charges	$ 1,488	$ 1,407	$ 1,391	$ 1,364	$ 1,119
Fixed Charges:					
Interest expense	$ 380	$ 379	$ 379	$ 379	$ 380
Estimated interest portion of rentals charged to expense	5	5	5	6	5
Total fixed charges	$ 385	$ 384	$ 384	$ 385	$ 385
Ratio of Earnings to Fixed Charges	3.9x	3.7x	3.6x	3.5x	2.9x

EXHIBIT 12.2

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

	Years Ended December 31,				
	2016	2015	2014	2013	2012
Earnings Available for Fixed Charges:					
Income from continuing operations before income tax expense	$ 1,103	$ 1,023	$ 1,007	$ 979	$ 734
Fixed charges	385	384	384	385	385
Total earnings available for fixed charges	$ 1,488	$ 1,407	$ 1,391	$ 1,364	$ 1,119
Fixed Charges and Preferred Stock Dividends:					
Interest expense	$ 380	$ 379	$ 379	$ 379	$ 380
Estimated interest portion of rentals charged to expense	5	5	5	6	5
Total fixed charges	385	384	384	385	385
Preferred stock dividends [1]	—	—	—	2	3
Total fixed charges and preferred stock dividends	$ 385	$ 384	$ 384	$ 387	$ 388
Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends	3.9x	3.7x	3.6x	3.5x	2.9x

(1) Represents actual preferred stock dividends grossed up for income taxes.

NEVADA POWER COMPANY
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars in millions)

	Years Ended December 31,				
	2016	**2015**	**2014**	**2013**	**2012**
Earnings available for fixed charges:					
Net income	$ 279	$ 288	$ 227	$ 145	$ 258
Add (deduct):					
Income tax expense	146	162	130	94	138
Fixed charges	185	190	211	220	220
Capitalized interest (allowance for borrowed funds used during construction)	(4)	(3)	(1)	(6)	(5)
	327	349	340	308	353
Total earnings available for fixed charges	$ 606	$ 637	$ 567	$ 453	$ 611
Fixed charges -					
Interest expense	185	190	211	220	220
Total fixed charges	$ 185	$ 190	$ 211	$ 220	$ 220
Ratio of earnings to fixed charges	3.3x	3.4x	2.7x	2.1x	2.8x

EXHIBIT 12.4

SIERRA PACIFIC POWER COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
(Dollars in Millions)

	Years Ended December 31,				
	2016	**2015**	**2014**	**2013**	**2012**
Earnings available for fixed charges:					
Net income	$ 84	$ 83	$ 87	$ 55	$ 84
Add (deduct):					
Income tax expense	49	47	47	33	40
Fixed charges	56	61	63	62	66
Capitalized interest (allowance for borrowed funds used during construction)	(4)	(2)	(2)	(2)	(2)
	101	106	108	93	104
Total earnings available for fixed charges	$ 185	$ 189	$ 195	$ 148	$ 188
Fixed charges -					
Interest expense	56	61	63	62	66
Total fixed charges	$ 56	$ 61	$ 63	$ 62	$ 66
Ratio of earnings to fixed charges	3.3x	3.1x	3.1x	2.4x	2.8x

EXHIBIT 21.1

BERKSHIRE HATHAWAY ENERGY COMPANY
SUBSIDIARIES AND JOINT VENTURES

Pursuant to Item 601(b)(21)(ii) of Regulation S-K, we have omitted certain subsidiaries (all of which, when considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary as of the end of our last fiscal year).

PPW Holdings LLC	Delaware
PacifiCorp	Oregon
MidAmerican Funding, LLC	Iowa
MHC Inc.	Iowa
MidAmerican Energy Company	Iowa
NVE Holdings, LLC	Delaware
NV Energy, Inc.	Nevada
Nevada Power Company d/b/a NV Energy	Nevada
Sierra Pacific Power Company d/b/a NV Energy	Nevada
Northern Powergrid Holdings Company	England
Northern Powergrid U.K. Holdings	England
Northern Powergrid Limited	England
Northern Electric plc.	England
Northern Powergrid (Northeast) Limited	England
Yorkshire Power Group Limited	England
Yorkshire Electricity Group plc.	England
Northern Powergrid (Yorkshire) plc.	England
NNGC Acquisition, LLC	Delaware
Northern Natural Gas Company	Delaware
KR Holding, LLC	Delaware
Kern River Gas Transmission Company	Texas
BHE Canada, LLC	Delaware
BHE Canada Holdings Corporation	Alberta
BHE AltaLink Ltd.	Canada
AltaLink Holdings, L.P.	Canada
AltaLink Investments, L.P.	Canada
AltaLink, L.P.	Canada
BHE U.S. Transmission, LLC	Delaware
BHE Renewables, LLC	Delaware
HomeServices of America, Inc.	Delaware

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-214946 on Form S-8 of our report dated February 24, 2017, relating to the consolidated financial statements and financial statement schedules of Berkshire Hathaway Energy Company and subsidiaries, appearing in this Annual Report on Form 10-K of Berkshire Hathaway Energy Company for the year ended December 31, 2016.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 24, 2017

EXHIBIT 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-207687 on Form S-3 of our report dated February 24, 2017, relating to the consolidated financial statements of PacifiCorp and subsidiaries appearing in this Annual Report on Form 10-K of PacifiCorp for the year ended December 31, 2016.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 24, 2017

EXHIBIT 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-206980 on Form S-3 of our report dated February 24, 2017, relating to the financial statements and financial statement schedule of MidAmerican Energy Company (which report expresses an unqualified opinion and includes an emphasis of a matter paragraph relating to MidAmerican Energy Company transferring its assets and liabilities of its unregulated retail services business to a subsidiary of its parent, Berkshire Hathaway Energy Company on January 1, 2016), appearing in this Annual Report on Form 10-K of MidAmerican Energy Company for the year ended December 31, 2016.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 24, 2017

EXHIBIT 23.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-213897 on Form S-3 of our report dated February 24, 2017 relating to the consolidated financial statements of Nevada Power Company and subsidiaries appearing in this Annual Report on Form 10-K of Nevada Power Company for the year ended December 31, 2016.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 24, 2017

EXHIBIT 24.1

POWER OF ATTORNEY

The undersigned, a member of the Board of Directors or an officer of BERKSHIRE HATHAWAY ENERGY COMPANY, an Iowa corporation (the "Company"), hereby constitutes and appoints Natalie L. Hocken and Paul J. Leighton and each of them, as his/her true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for and in his/her stead, in any and all capacities, to sign on his/her behalf the Company's Annual Report on Form 10-K for the fiscal year ending December 31, 2016 and to execute any amendments thereto and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission and applicable stock exchanges, with the full power and authority to do and perform each and every act and thing necessary or advisable to all intents and purposes as he/she might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent, or his/her substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Executed as of February 24, 2017

/s/ Gregory E. Abel
GREGORY E. ABEL

/s/ Warren E. Buffett
WARREN E. BUFFETT

/s/ Walter Scott, Jr.
WALTER SCOTT, JR.

/s/ Patrick J. Goodman
PATRICK J. GOODMAN

/s/ Marc D. Hamburg
MARC D. HAMBURG

EXHIBIT 31.1

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

I, Gregory E. Abel, certify that:

1. I have reviewed this Annual Report on Form 10-K of 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: February 24, 2017

/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 Annual Report on Form 10-K 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: February 24, 2017

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

EXHIBIT 31.3

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

I, Gregory E. Abel, certify that:

1. I have reviewed this Annual Report on Form 10-K of PacifiCorp;

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

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

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

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

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

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

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

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

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

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

Date: February 24, 2017

/s/ Gregory E. Abel
Gregory E. Abel
Chairman of the Board of Directors and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.4

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

I, Nikki L. Kobliha, certify that:

1. I have reviewed this Annual Report on Form 10-K of PacifiCorp;

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

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

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

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

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

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

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

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

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

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

Date: February 24, 2017

/s/ Nikki L. Kobliha
Nikki L. Kobliha
Director, Vice President, Chief Financial Officer, and Treasurer
(principal financial officer)

EXHIBIT 31.5

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

I, William J. Fehrman, certify that:

1. I have reviewed this annual report on Form 10-K of MidAmerican 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 controls over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

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

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

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

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

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

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

Date: February 24, 2017

/s/ William J. Fehrman
William J. Fehrman
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.6

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

I, Thomas B. Specketer, certify that:

1. I have reviewed this annual report on Form 10-K of MidAmerican 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 controls over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

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

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

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

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

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

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

Date: February 24, 2017

/s/ Thomas B. Specketer
Thomas B. Specketer
Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 31.7

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

I, William J. Fehrman, certify that:

1. I have reviewed this annual report on Form 10-K of MidAmerican Funding, LLC;

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 controls over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

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

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

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

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

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

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

Date: February 24, 2017

/s/ William J. Fehrman
William J. Fehrman
President
(principal executive officer)

EXHIBIT 31.8

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

I, Thomas B. Specketer, certify that:

1. I have reviewed this annual report on Form 10-K of MidAmerican Funding, LLC;

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 controls over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

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

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

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

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

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

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

Date: February 24, 2017

/s/ Thomas B. Specketer
Thomas B. Specketer
Vice President and Controller
(principal financial officer)

EXHIBIT 31.9

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

I, Paul J. Caudill, certify that:

1. I have reviewed this Annual Report on Form 10-K of Nevada Power Company (dba NV Energy);

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

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

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

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

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

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

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

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

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

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

Date: February 24, 2017

/s/ Paul J. Caudill
Paul J. Caudill
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.10

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

I, E. Kevin Bethel, certify that:

1. I have reviewed this Annual Report on Form 10-K of Nevada Power Company (dba NV Energy);

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

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

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

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

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

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

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

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

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

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

Date: February 24, 2017

/s/ E. Kevin Bethel
E. Kevin Bethel
Senior Vice President, Chief Financial Officer and Director
(principal financial officer)

EXHIBIT 31.11

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

I, Paul J. Caudill, certify that:

1. I have reviewed this Annual Report on Form 10-K of Sierra Pacific Power Company (dba NV Energy);

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

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

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

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

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

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

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

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

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

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

Date: February 24, 2017

/s/ Paul J. Caudill
Paul J. Caudill
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.12

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

I, E. Kevin Bethel, certify that:

1. I have reviewed this Annual Report on Form 10-K of Sierra Pacific Power Company (dba NV Energy);

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

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

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

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

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

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

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

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

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

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

Date: February 24, 2017

/s/ E. Kevin Bethel
E. Kevin Bethel
Senior Vice President, Chief Financial Officer and Director
(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 Annual Report on Form 10-K of the Company for the annual period ended December 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

Date: February 24, 2017

/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 Annual Report on Form 10-K of the Company for the annual period ended December 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

Date: February 24, 2017

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

EXHIBIT 32.3

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

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

(1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o (d)); and

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

Date: February 24, 2017

/s/ Gregory E. Abel
Gregory E. Abel
Chairman of the Board of Directors and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.4

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

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

(1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o (d)); and

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

Date: February 24, 2017

/s/ Nikki L. Kobliha
Nikki L. Kobliha
Director, Vice President, Chief Financial Officer, and Treasurer
(principal financial officer)

EXHIBIT 32.5

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

I, William J. Fehrman, President of MidAmerican 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 Annual Report on Form 10-K of the Company for the annual period ended December 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o (d)); and

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

Date: February 24, 2017

/s/ William J. Fehrman
William J. Fehrman
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.6

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

I, Thomas B. Specketer, Vice President and Chief Financial Officer of MidAmerican 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 Annual Report on Form 10-K of the Company for the annual period ended December 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o (d)); and

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

Date: February 24, 2017

/s/ Thomas B. Specketer
Thomas B. Specketer
Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 32.7

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

I, William J. Fehrman, President of MidAmerican Funding, LLC (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o (d)); and

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

Date: February 24, 2017

/s/ William J. Fehrman
William J. Fehrman
President
(principal executive officer)

EXHIBIT 32.8

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

I, Thomas B. Specketer, Vice President and Controller of MidAmerican Funding, LLC (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o (d)); and

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

Date: February 24, 2017

/s/ Thomas B. Specketer
Thomas B. Specketer
Vice President and Controller
(principal financial officer)

EXHIBIT 32.9

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

I, Paul J. Caudill, President of Nevada Power Company (dba NV Energy), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of Nevada Power Company for the annual period ended December 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

Date: February 24, 2017

/s/ Paul J. Caudill
Paul J. Caudill
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.10

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

I, E. Kevin Bethel, Chief Financial Officer of Nevada Power Company (dba NV Energy), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of Nevada Power Company for the annual period ended December 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

Date: February 24, 2017

/s/ E. Kevin Bethel
E. Kevin Bethel
Senior Vice President, Chief Financial Officer and Director
(principal financial officer)

EXHIBIT 32.11

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

I, Paul J. Caudill, President of Sierra Pacific Power Company (dba NV Energy), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of Sierra Pacific Power Company for the annual period ended December 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

Date: February 24, 2017

/s/ Paul J. Caudill
Paul J. Caudill
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.12

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

I, E. Kevin Bethel, Chief Financial Officer of Sierra Pacific Power Company (dba NV Energy), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of Sierra Pacific Power Company for the annual period ended December 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

Date: February 24, 2017

/s/ E. Kevin Bethel
E. Kevin Bethel
Senior Vice President, Chief Financial Officer and Director
(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 year ended December 31, 2016 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 as no reportable events occurred at those locations during the year ended December 31, 2016. There were no mining-related fatalities during the year ended December 31, 2016. 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 year ended December 31, 2016.

	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
Bridger (surface)	5	—	—	—	—	$ 12	5	3	4
Bridger (underground)	37	—	—	—	—	74	4	9	10
Wyodak Coal Crushing Facility	1	—	—	—	—	—	—	—	—

(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, two contests of citations or orders under Subpart B and one labor-related complaint under Subpart E of the Federal Mine Safety and Health Review Commission's procedural rules. The pending legal actions are not exclusive to citations, notices, orders and penalties assessed by MSHA during the reporting period.