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, 2014

or

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

For the transition period from _____ to _____

Commission File Number	Exact name of registrant as specified in its charter; State or other jurisdiction of incorporation or organization	IRS Employer Identification No.
000-52378	**NEVADA POWER COMPANY** **(A Nevada Corporation)** **6226 West Sahara Avenue** **Las Vegas, Nevada 89146** **702-402-5000**	**88-0420104**

Securities registered pursuant to Section 12(b) of the Act: None
Securities registered pursuant to Section 12(g) of the Act:
Common Stock, $1.00 stated value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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

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

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

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

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

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

All shares of outstanding common stock of Nevada Power Company are held by its parent company, NV Energy, Inc., which is an indirect, wholly owned subsidiary of Berkshire Hathaway Energy Company. As of January 31, 2015, 1,000 shares of common stock, $1.00 stated value, were outstanding.

Nevada Power Company meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing portions of this Form 10-K with the reduced disclosure format specified in General Instruction I(2) of Form 10-K.

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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 Items 9 through 9B, and Part III - Items 10 and 14, the following terms have the definitions indicated.

Nevada Power Company and Related Entities

Company	Nevada Power Company and its subsidiaries
BHE	Berkshire Hathaway Energy Company
NV Energy	NV Energy, Inc.
Berkshire Hathaway	Berkshire Hathaway Inc.
Sierra Pacific	Sierra Pacific Power Company, an electric and natural gas utility wholly owned by NV Energy
Clark Generating Station	1,103-megawatt generating facility in Nevada
Goodsprings	5-megawatt waste heat recovery facility in Nevada
Harry Allen Generating Station	628-megawatt generating facility in Nevada
Higgins Generating Station	530-megawatt generating facility in Nevada
Lenzie Generating Station	1,102-megawatt generating facility in Nevada
Las Vegas Generating Station	272-megawatt generating facility in Nevada
Navajo Generating Station	2,250-megawatt generating facility in Arizona
Nellis Generating Station	15-megawatt generating facility under construction in Nevada
ON Line	500-kilovolt transmission line connecting the Company and Sierra Pacific
Reid Gardner Generating Station	257-megawatt generating facility in Nevada
Silverhawk Generating Station	520-megawatt generating facility in Nevada
Sun Peak Generating Station	210-megawatt generating facility in Nevada

Certain Industry Terms

AFUDC	Allowance for Funds Used During Construction
California ISO	California Independent System Operator Corporation
Dth	Decatherms
EEIR	Energy Efficiency Implementation Rate
EIM	Energy Imbalance Market
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gases
GWh	Gigawatt Hours
IRP	Integrated Resource Plan
kV	Kilovolt
MATS	Mercury and Air Toxics Standards
MW	Megawatts
MWh	Megawatt Hours
NERC	North American Electric Reliability Corporation
PUCN	Public Utilities Commission of Nevada
RPS	Renewable Portfolio Standard
SEC	United States Securities and Exchange Commission
SIP	State Implementation Plan

Forward-Looking Statements

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

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

- other business or investment considerations that may be disclosed from time to time in the Company's filings with the SEC or in other publicly disseminated written documents.

Further details of the potential risks and uncertainties affecting the Company are described in Item 1A and other discussions contained in this Form 10-K. The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing factors should not be construed as exclusive.

PART I

Item 1. Business

General

The Company 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. Generating, transmitting, distributing and selling electricity are the principal business operations of the Company, which is over a service territory covering approximately 4,500 square miles. The Company also 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. The Company is subject to comprehensive state and federal regulation. Regulated electric utility operation is the Company's only segment. Principal industries served by the Company include gaming, recreation, warehousing, manufacturing and government. In addition to retail sales, the Company sells electricity to other utilities, municipalities and energy marketing companies on a wholesale basis. The Company is a wholly owned subsidiary of NV Energy, a holding company that also owns Sierra Pacific and certain other subsidiaries. NV Energy is an indirect wholly owned subsidiary of 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.

On December 19, 2013, the merger contemplated by the Agreement and Plan of Merger dated May 29, 2013 among BHE, Silver Merger Sub, Inc. ("Merger Sub"), BHE's wholly owned subsidiary, and NV Energy, whereby Merger Sub was merged into NV Energy and NV Energy became an indirect wholly owned subsidiary of BHE ("BHE Merger") was completed.

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

Operations

The Company delivers electricity to customers in Nevada. The Company owns or has contracts for coal, natural gas, water, wind, solar and geothermal 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, the 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 Company's distribution system.

The Company's primary goal is to provide safe, reliable electricity to its customers at a reasonable cost. In return, the Company expects that all prudently incurred costs to provide such service will be included as allowable costs for ratemaking purposes and that it will be allowed an opportunity to earn a reasonable return on its investments.

The Company's regulated electric operation is conducted under numerous nonexclusive franchise agreements, revocable permits and licenses obtained from federal, state and local authorities. The expiration of these franchise agreements range from 2020 through 2032. In addition, the Company operates under certificates of public convenience and necessity as regulated by the PUCN, and as such the Company has 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 Company an opportunity to recover their costs of providing services and to earn a reasonable return on their investment.

The Company seeks to manage growth in its customer demand through the construction and purchase of cost-effective, environmentally prudent and efficient sources of electricity supply and through energy efficiency programs. The Company and Sierra Pacific constructed a 500-kV transmission line to connect the two companies. The ON Line transmission line was placed in-service on December 31, 2013. The Company has announced plans to join the EIM in October 2015. The Company and the California ISO will extend the scope of the existing EIM, which is expected to reduce costs to serve customers through more efficient dispatch of a larger and more diverse pool of resources, more effectively integrate renewables and enhance reliability through improved situational awareness and responsiveness.

Employees

As of December 31, 2014, the Company had approximately 1,400 employees, of which approximately 700 were covered by a collective bargaining agreement with the International Brotherhood of Electrical Workers.

Customers

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

	2014		2013		2012	
GWh sold:						
Residential	8,923	42%	9,012	42%	9,098	42%
Commercial	4,489	21	4,426	21	4,500	21
Industrial	7,486	36	7,533	36	7,666	36
Other	211	1	212	1	217	1
Total retail	21,109	100	21,183	100	21,481	100
Wholesale	20	—	36	—	61	—
Total GWh sold	21,129	100%	21,219	100%	21,542	100%
Average number of retail customers (in thousands):						
Residential	770	88%	754	88%	746	88%
Commercial	102	12	103	12	101	12
Industrial	2	—	2	—	2	—
Total	874	100%	859	100%	849	100%

In addition to the variations in weather from year to year, fluctuations in economic conditions within the service territory and elsewhere can impact customer usage, particularly for gaming 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 Company's electric business that are principally related to the use of electricity for air conditioning and the related effects of weather. Typically, 45-50% of the Company's regulated electric revenue is reported in the months of June, July, August and September.

The annual hourly peak customer demand on the Company's electric system 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 1, 2014, the Company's retail customer usage of electricity caused an hourly peak demand of 5,572 MW on the Company's electric distribution system, which is 282 MW less than the record hourly peak demand of 5,854 MW set July 2, 2013.

Generating Facilities and Fuel Supply

The Company is required to have resources available to continuously meet its customer needs. The percentage of the Company'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. The Company evaluates these factors continuously in order to facilitate economical dispatch of its generating facilities. When factors for one energy source are less favorable, the Company must place more reliance on other energy sources. As long as the Company's purchases are deemed prudent by the PUCN, through its annual prudency review, the Company is permitted to recover the cost of fuel and purchased power. The Company also has the ability to reset quarterly base tariff rates based on the last twelve months fuel costs and purchased power and to reset quarterly deferred energy annual adjustments.

In response to these energy supply challenges, the Company has adopted an approach to managing the energy supply function that has three primary elements. The first element is a set of management guidelines for procuring and optimizing the supply portfolio that is consistent with the requirements of a load serving entity with a full requirements obligation. 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 Company will pursue a process of ongoing regulatory involvement and acknowledgment of the resource portfolio management plans.

The Company has entered into multiple long-term power purchase contracts (three or more years) with suppliers that generate electricity utilizing natural gas and renewable resources with a total nameplate capacity of 2,009 MW and contract termination dates ranging from 2017 to 2040. Included in these contracts are 814 MW of nameplate capacity of renewable energy, of which 178 MW of nameplate capacity are under development or construction and not currently available.

The Company manages certain risks relating to its 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 "General Regulation" in Item 1 of this Form 10-K for a discussion of energy cost recovery by jurisdiction and Item 7A in this Form 10-K for a discussion of commodity price risk and derivative contracts.

The Company has ownership interests in a diverse portfolio of generating facilities. The following table presents certain information regarding the Company's owned generating facilities as of December 31, 2014:

Generating Facility	Location	Energy Source	Installed	Facility Net Capacity (MW)[1]	Net Owned Capacity (MW)[1]
COAL:					
Reid Gardner Unit No.4[2]	Moapa, NV	Coal	1983	257	257
Navajo Unit No. 1, 2 and 3[2]	Page, AZ	Coal	1974-1976	2,250	255
				2,507	512
NATURAL GAS:					
Clark	Las Vegas, NV	Natural gas	1973-2008	1,103	1,103
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	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	1991	210	210
				4,365	4,235
OTHER:					
Goodsprings	Goodsprings, NV	Waste heat	2010	5	5
Total available generating capacity				6,877	4,752
PROJECTS UNDER CONSTRUCTION					
Nellis	Las Vegas, NV	Solar		15	15
				6,892	4,767

(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 under specified conditions. Net Owned Capacity indicates the Company's ownership of Facility Net Capacity.

(2) The Company currently anticipates retiring Reid Gardner Unit No. 4 in December 2017 and Navajo Unit Nos. 1, 2 and 3 in 2019. Reid Gardner Unit Nos. 1, 2 and 3 were retired in December 2014. Refer to "Environmental Laws and Regulations" in Item 7 of this Form 10-K for further discussion.

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

	2014	2013	2012
Natural gas	56%	65%	65%
Coal	20	13	9
Total energy generated	76	78	74
Energy purchased - short-term contracts and other	1	3	5
Energy purchased - long-term contracts (renewable)[1]	10	10	14
Energy purchased - long-term contracts (non-renewable)	13	9	7
	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.

Natural Gas

To secure natural gas supplies for the generating facilities the Company either owns or has under long-term contract (tolling arrangements), the Company contracts for firm winter, summer, and annual natural gas supplies with numerous domestic suppliers. In 2014, natural gas supply net purchases averaged 269,438 Dth per day, with the winter period contracts averaging 226,919 Dth per day and the summer period contracts averaging 307,298 Dth per day. The Company believes supplies from these sources are presently adequate and available to meet its needs.

The Company contracts for firm natural gas pipeline capacity to transport natural gas from production areas to its service territory through direct interconnects to the pipeline systems of two interstate natural gas pipeline systems, including Kern River Gas Transmission Company, an affiliated company.

Coal

The Company has no coal commitments for Reid Gardner Unit No. 4 for 2015 or beyond and will rely on spot market solicitations for any coal supplies needed during 2015.The coal supply plan has the overall goal of eliminating its coal pile by the end of 2017. The rail transportation service contract between the Company and Union Pacific Railroad Company expired December 31, 2014. This contract contained a volume shortfall provision, which was accrued as of December 31, 2014, and payment is due in May 2015. The Navajo Generating Station, jointly owned by the Company along with five other entities and operated by Salt River Project, has a coal sales agreement that extends through 2019. The Company manages their coal supplies based on anticipated needs and through various arrangements including spot purchases and long- and short-term contracts. The Company regularly monitors the western coal market for opportunities to enhance its coal supply portfolios.

Transmission and Distribution

The Company'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. The Company's transmission system, together with contractual rights on other transmission systems, enables the Company to integrate and access generation resources to meet its customer load requirements. The Company's transmission and distribution systems included approximately 2,000 miles of transmission lines, 24,000 miles of distribution lines and 200 substations as of December 31, 2014.

On December 31, 2013, the Company, along with Sierra Pacific, completed construction and placed in-service ON Line, a 231 mile, 500-kV transmission line connecting the Company's and Sierra Pacific's service territories. ON Line has enabled the Company and Sierra Pacific to optimize their generation assets by enhancing their transmission capabilities. 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 will enhance the Company's and Sierra Pacific's ability to manage and optimize their generating facilities. ON Line provides between 600 and 800 MW of transfer capability between northern and southern Nevada. ON Line was a joint project between the Company, Sierra Pacific and Great Basin Transmission, LLC. With the completion of ON Line, the parties completed construction of a 500-kV interconnection between the Robinson Summit substation on the Sierra Pacific system and the Harry Allen substation on the Company's system. The Company and Sierra Pacific 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 for a term of 41 years. The Company's and Sierra Pacific's share of their 25% interest in ON Line and the long-term transmission use agreement is split at 95% and 5%, respectively.

Energy Imbalance Market

The Company has announced plans to join the EIM in October 2015. The EIM is expected to reduce costs to serve customers through more efficient dispatch of a larger and more diverse pool of resources, more effectively integrate renewables and enhance reliability through improved situational awareness and responsiveness. In today's environment, utilities in the Western United States outside the EIM footprint rely upon a combination of automated and manual dispatch within the hour to balance generation and load to maintain reliable supply and have limited capability to transact within the hour outside their own borders. In contrast, the EIM expands the real-time component of the California ISO to optimize and balance electricity supply and demand every five minutes across the EIM footprint. 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 transmission grid network, meteorological and load forecast information that it uses to optimize dispatch instructions. The EIM is voluntary and available to all balancing authorities in the Western United States. Benefits to customers are expected to increase with renewable resource expansion as more entities join the EIM bringing incremental diversity. The PUCN's final order approving the merger between BHE and NV Energy stipulated that the Company would obtain PUCN authorization prior to participating in an EIM. In April 2014, the Company filed an application to amend its portfolio optimization procedures contained in the PUCN-approved energy supply plan to include EIM starting October 2015. The amendment reflects the Company's participation in the EIM that is being established by the California ISO.

The filing requested the PUCN to determine that the amended energy supply plan balances the objectives of minimizing the cost of supply and retail price volatility, maximizes the reliability of supply over the remaining term of the plan, optimizes the value of the overall supply portfolio of the Company for the benefit of bundled retail customers and does not contain any features or mechanisms that the PUCN finds would impair the restoration or the creditworthiness of the Company. The PUCN issued an order in August 2014 finding that it is in the public interest to grant the application and that NV Energy met the merger stipulation requirement to obtain PUCN approval prior to participating in an EIM. In April 2014, the California ISO filed the Implementation Agreement entered into by the Company and the California ISO. The Implementation Agreement provides the mechanism by which the Company will compensate the California ISO for its share of the costs to upgrade systems, software licenses and other configuration activities. The Implementation Agreement was approved by the FERC in June 2014.

Future Generation

The Company files IRPs every three years, and as necessary, may file amendments to its 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 the Company's customers. Projects approved through the IRP process still remain subject to review by the PUCN. The Company is scheduled to file a triennial IRP before July 1, 2015.

The energy supply function at the Company is responsible for the operation of the Company's owned generation, the procurement of all fuels and purchased power and optimization of resources (e.g., physical and economic dispatch).

There is the potential for continued price volatility in the Company's service territory, particularly during peak periods. Too great 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 Company faces load obligation uncertainty due to the potential for customer switching. Some counterparties in these areas have significant credit difficulties, representing credit risk to the Company. Finally, the Company's 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 Company provides a comprehensive set of energy efficiency, demand response and conservation programs to its 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 engineering audits and information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, the Company 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. Energy efficiency program costs are recovered through annual rates set by the PUCN, and adjusted based on the Company's annual filing to recover current program costs and any over or under collections from the prior filing, subject to prudence review. During 2014, the Company spent $40 million on energy efficiency programs resulting in an estimated 145,937 MWh of electric energy savings and an estimated 37 MW of electric peak load management.

General Regulation

The Company is subject to comprehensive governmental regulation, which significantly influences its operating environment, prices charged to customers, capital structure, costs and, ultimately, its ability to recover costs. In addition to the following discussion, refer to "Regulatory Matters" in Item 7 of this Form 10-K.

State Regulation

Historically, the PUCN has established retail electric rates on a cost-of-service basis, which are designed to allow the utility an opportunity to recover what the PUCN 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, the 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. The PUCN may, as a result of a statutorily mandated general rate proceeding, adjust rates 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. The PUCN typically has 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. The utility and such parties may also enter into stipulations regarding changes to rates, though such stipulations are subject to PUCN approval.

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

The Company generally has an exclusive right to serve retail customers within its service territory, and in turn, has an obligation to provide service to those customers. Certain classes of customers may choose to purchase all or a portion of their energy from alternative energy suppliers, and retail customers can generate all or a portion of their own energy. 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 Company, the departure must not burden the Company 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. In November 2014, one retail electric customer filed a letter of intent and the application is pending with the PUCN in the Company's service territory. Also, the Company is evaluating how best to integrate distributed generation resources into its 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.

Nevada statutes require the Company to file electric general rate cases at least once every three years with the PUCN. The Company is also subject to a two-part fuel and purchased power adjustment mechanism. The Company makes quarterly filings to reset Base Tariff Energy Rates ("BTER"), based on the last 12 months 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. During required annual Deferred Energy Accounting Adjustment ("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 subsequent quarterly BTER rate change. Additionally, 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 Company received approval from the PUCN and files quarterly adjustments to the DEAA rate to clear amounts deferred into the balancing account. The Company also files annually for the recovery of lost revenue that is attributable to the measurable and verifiable effects associated with the implementation of efficiency and conservation programs approved by the PUCN, as well as, the implementation costs of energy efficiency programs.

Joint Application of the Company and Sierra Pacific

The Company and Sierra Pacific became physically interconnected for the first time on January 1, 2014 and are presently joint dispatching generation facilities pursuant to an interim joint dispatch agreement approved by the FERC. In October 2014, the Company and Sierra Pacific filed a motion for renewal of the interim joint dispatch agreement to extend the agreement through December 2015 and received acceptance from the FERC in November 2014. The Company and Sierra Pacific are presently seeking PUCN approval of a long-term joint dispatch agreement, which will be filed with the FERC in time to go into effect on January 1, 2016.

Federal Regulation

The FERC is an independent agency with broad authority to implement provisions of the Federal Power Act, 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; and other matters. The FERC also has the enforcement authority to assess civil penalties of up to $1 million per day per violation of rules, regulations and orders issued under the Federal Power Act. The Company has implemented programs and procedures that facilitate and monitor compliance with the FERC's regulations described below.

Wholesale Electricity and Capacity

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

The Company's authority to sell electricity in wholesale electricity markets at market-based rates is subject to triennial reviews conducted by the FERC. During such reviews, the Company must demonstrate a lack of market power over sales of wholesale electricity and electric generation capacity in its market area. The Company's most recent triennial filing was made in July 2013 and approved by the FERC in April 2014. Under the FERC's market-based rules, the Company 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.

Transmission

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

FERC Reliability Standards

The FERC has established an extensive number of mandatory reliability standards developed by the NERC and the Western Electricity Coordinating Council ("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.

Environmental Laws and Regulations

The Company 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 the Company's 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 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 the Company is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. The Company believes it is in material compliance with all applicable laws and regulations.

Refer to "Environmental Laws and Regulations" in Item 7 of this Form 10-K for additional information regarding environmental laws and regulations and "Liquidity and Capital Resources" for the Company's forecasted environmental-related capital expenditures.

Item 1A. Risk Factors

We are 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 us, should be made before making an investment decision. Additional risks and uncertainties not presently known or which we currently deem immaterial may also impair our business operations.

We are subject to operating uncertainties and events beyond our control that impact the costs to operate, maintain, repair and replace utility systems, which could adversely affect our consolidated financial results.

The operation of complex utility systems that are spread over large geographic areas involves many operating uncertainties and events beyond our control. These potential events include the breakdown or failure of our thermal and other electricity generating facilities and related equipment, 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; terrorist activities or military or other actions, including cyberattacks; fuel shortages or interruptions; unavailability of critical equipment, materials and supplies; weather-related impacts; performance below expected levels of output, capacity or efficiency; operator error; design, construction or manufacturing defects; and catastrophic events such as severe storms, floods, fires, earthquakes, explosions, landslides, wars, terrorism and embargoes. A catastrophic event might result in injury or loss of life, extensive property damage or environmental or natural resource damages. Any of these events or other operational events could significantly reduce or eliminate our revenue or significantly increase our expenses. For example, if we cannot operate our generating facilities at full capacity due to damage caused by a catastrophic event, our revenue could decrease and our expenses could increase due to the need to obtain energy from more expensive sources. Further, we self-insure many risks, and current and future insurance coverage may not be sufficient to replace lost revenue or cover repair and replacement costs. The scope, cost and availability of our insurance coverage may change, including the portion that is self-insured. Any reduction of our revenue or increase in our expenses resulting from the risks described above, could adversely affect our consolidated financial results.

We are subject to extensive federal, state and local legislation and regulation, including numerous environmental, health, safety, reliability and other laws and regulations that affect our operations and costs. These laws and regulations are complex, dynamic and subject to new interpretations or change. In addition, new laws and regulations are continually being proposed and enacted that impose new or revised requirements or standards on our business.

We are required to comply with numerous federal, state and local laws and regulations as described in Item 1 of this Form 10-K that have broad application to our business and limit our 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; setting rates charged to customers; establishing capital structures and issuing debt or equity securities; transacting with affiliates; and paying dividends or similar distributions. These laws and regulations are followed in developing our 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 Nevada Division of Environmental Protection, the Clark County Department of Air Quality and the PUCN.

Compliance with applicable laws and regulations generally requires us 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, we could be required to shut down some facilities or materially alter their operations. Further, we may not be able to obtain or maintain all required environmental or other regulatory approvals and permits for our 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 us from operating our facilities, developing or favorably locating new facilities or expanding existing facilities. If we fail to comply with any environmental or other regulatory requirements, we may be subject to penalties and fines or other sanctions, including changes to the way our electricity generating facilities are operated that may adversely impact generation. The costs of complying with laws and regulations could adversely affect our consolidated financial results. Not being able to operate existing facilities or develop new generating facilities to meet customer electricity needs could require us to increase our purchases of electricity on the wholesale market, which could increase market and price risks and adversely affect our 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 our service territory; new environmental requirements, including the implementation of 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 our service territory as a result of condemnation or takeover by municipalities or other governmental entities, particularly where we lack the exclusive right to serve our customers; the ability to recover our costs on a timely basis, if at all; or a negative impact on our 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 our business.

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. We 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 we determine their impact on us at this time; however, any one of these could adversely affect our consolidated financial results through higher capital expenditures and operating costs or restrict or otherwise cause an adverse change in how we operate our business. To the extent that we are not allowed by our 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 our consolidated financial results. Additionally, even if such costs are recoverable in rates, if they are substantial and result in rates increasing to levels that substantially reduce customer demand, this could have a material adverse effect on our consolidated financial results.

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

State Rate Proceedings

Rates are established for our 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 us to ensure system reliability. Decisions are subject to judicial appeal, potentially leading to further uncertainty associated with the approval proceedings.

Retail rates in Nevada are based in part upon the state regulatory commission's determination of total utility costs. 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. Furthermore, the PUCN generally sets rates based on a test year established in accordance with the PUCN's policies. The test year data adopted may create a lag between the incurrence of a cost and its recovery in rates. The PUCN 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 standards. Additionally, the PUCN establishes the allowed rate of return we will be given an opportunity to earn on our sources of capital. While rate regulation is premised on providing a fair opportunity to earn a reasonable rate of return on invested capital, the PUCN does not guarantee that we will be able to realize a reasonable rate of return.

FERC Jurisdiction

The FERC authorizes cost-based rates associated with transmission services provided by our transmission facilities. Under the Federal Power Act, we may voluntarily file, or may be obligated to file, for changes, including general rate changes, to our 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 we sell electricity at wholesale 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 our ability to sell electricity at market-based rates, which could adversely affect our consolidated financial results. The FERC also maintains rules concerning standards of conduct, affiliate restrictions, interlocking directorates and cross-subsidization. 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 transmission grid and generation system. We 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.

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

We actively pursue, develop and construct new or expanded facilities. We expect that we will incur substantial annual capital expenditures over the next several years. Such expenditures include and may include in the future, among others, construction and other costs for new electricity generating facilities, electric transmission or distribution projects, environmental control and compliance 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 our suppliers, customers and contractors. Certain of our 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 rates we are able to charge our 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 our consolidated financial results.

Furthermore, we depend upon both internal and external sources of liquidity to provide working capital and to fund capital requirements. If we are unable to obtain funding from internal and external sources, we may need to postpone or cancel planned capital expenditures.

Failure to construct our planned projects could limit opportunities for growth, increase operating costs and adversely affect the reliability of electricity service to our customers. For example, if we are not able to expand our existing portfolio of generating facilities, we may be required to enter into long-term wholesale electricity purchase contracts or purchase wholesale electricity at more volatile and potentially higher prices in the spot markets to serve retail loads.

A significant sustained decrease in demand for electricity in the markets served by us would decrease our operating revenue, could impact our planned capital expenditures and could adversely affect our consolidated financial results.

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

- a depression, recession or other adverse economic condition that results in a lower level of economic activity or reduced spending by consumers on electricity;
- an increase in the market price of electricity or a decrease in the price of other competing forms of energy;
- efforts by customers, legislators and regulators to reduce the consumption of electricity generated or distributed by us through various conservation, energy efficiency and distributed generation measures and programs;
- higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of fuel sources for electricity generation or that limit the use of 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; and
- sustained mild weather that reduces heating or cooling needs.

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

In the markets in which we operate, demand for electricity peaks during the summer months when cooling needs are higher. Market prices for electricity also generally peak at that time. Further, extreme weather conditions, such as heat waves and floods could cause these seasonal fluctuations to be more pronounced.

As a result, our overall consolidated financial results may fluctuate substantially on a seasonal and quarterly basis. We have historically provided less service, and consequently earned less income, when weather conditions are mild. Unusually mild weather in the future may adversely affect our consolidated financial results through lower revenue or margins. Conversely, unusually extreme weather conditions could increase our costs to provide services and could adversely affect our consolidated financial results. The extent of fluctuation in our consolidated financial results may change depending on a number of factors related to our regulatory environment and contractual agreements, including our ability to recover energy costs and terms of our wholesale sale contracts.

We are subject to market risk associated with the wholesale energy markets, which could adversely affect our consolidated financial results.

In general, our primary market risk is adverse fluctuations in the market price of wholesale electricity and fuel, including natural gas and coal, which is compounded by volumetric changes affecting the availability of or demand for electricity and fuel. 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, we purchase electricity and fuel in the open market as part of our normal operating business. If market prices rise, especially in a time when larger than expected volumes must be purchased at market prices, we may incur significantly greater expense than anticipated. Likewise, if electricity market prices decline in a period when we are a net seller of electricity in the wholesale market, we could earn less revenue. Although we have energy cost adjustment mechanisms under applicable law, the risks associated with changes in market prices may not be fully mitigated.

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

Our long-term debt is rated investment grade by various rating agencies. We cannot assure that our long-term debt will continue to be rated investment grade in the future. Although none of our outstanding debt has rating-downgrade triggers that would accelerate a repayment obligation, a credit rating downgrade would increase our borrowing costs and commitment fees on our revolving credit agreements and other financing arrangements, perhaps significantly. In addition, we would likely be required to pay a higher interest rate in future financings, and the potential pool of investors and funding sources would likely decrease. Further, access to the commercial paper market could be significantly limited, resulting in higher interest costs.

Most of our large wholesale customers, suppliers and counterparties require us to have sufficient creditworthiness in order to enter into transactions, particularly in the wholesale energy markets. If our credit ratings were to decline, especially below investment grade, 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 us. Such amounts may be material and may adversely affect our liquidity and cash flows.

Potential terrorist activities and the impact of military or other actions, including cyberattacks, could adversely affect our 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 our operations to increased risks. Additionally, the United States government has issued warnings that energy assets, specifically pipeline, transmission and other electric utility infrastructure, are potential targets for terrorist attacks, including cyberattacks. Cyberattacks could adversely affect our ability to operate our facilities, information technology and business systems, or compromise confidential customer and employee information. Political, economic, social or financial market instability or damage to or interference with our operating assets or the assets of our 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 us in ways that cannot be predicted at this time. Any of these risks could materially affect our consolidated financial results. Furthermore, instability in the financial markets as a result of terrorism, sustained or significant cyberattacks, or war could also materially adversely affect our ability to raise capital.

We are subject to counterparty credit risk, which could adversely affect our consolidated financial results.

We are 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 we conduct business could impair the ability of these counterparties to meet their payment obligations. We depend on these counterparties to remit payments on a timely basis. We continue to monitor the creditworthiness of our 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 our wholesale suppliers' or customers' financial condition deteriorates or they otherwise become unable to pay, it could have a significant adverse impact on our liquidity and our consolidated financial results.

We are subject to counterparty performance risk, which could adversely affect our consolidated financial results.

We are subject to counterparty performance risk related to performance of contractual obligations by wholesale suppliers, customers and contractors. We rely 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 us to incur additional expenses to meet customer needs. In addition, when these contracts terminate, we may be unable to purchase the commodities on terms equivalent to the terms of current contracts.

We rely on wholesale customers to take delivery of the energy they have committed to purchase. Failure of customers to take delivery may require us to find other customers to take the energy at lower prices than the original customers committed to pay. If our wholesale customers are unable to fulfill their obligations, there may be a significant adverse impact on our consolidated financial results.

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

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

Poor performance of plan and fund investments and other factors impacting NV Energy's pension and other postretirement benefit plans in which we participate could unfavorably impact our consolidated financial results.

Costs of providing NV Energy's defined benefit pension and other postretirement benefit plans depend upon a number of factors, including the rates of return on plan assets, the level and nature of benefits provided, discount rates, mortality assumptions, the interest rates used to measure required minimum funding levels, changes in benefit design, tax deductibility and funding limits, changes in laws and government regulation and NV Energy's required or voluntary contributions made to the plans. Certain of NV Energy'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, we will likely be required to make cash contributions to fund these plans in the future. NV Energy's pension and other postretirement benefit 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. Such cash funding obligations, which are also impacted by the other factors described above, could have a material impact on our liquidity by reducing available cash.

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

Disruptions in the financial markets could affect our ability to obtain debt financing, draw upon or renew existing credit facilities, and have other adverse effects on us. Significant dislocations and liquidity disruptions in the United States 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 our ability to access funds on favorable terms or at all. If we are unable to access the bank and debt markets to meet liquidity and capital expenditure needs, it may adversely affect the timing and amount of our capital expenditures and our consolidated financial results.

We are involved in a variety of legal proceedings, the outcomes of which are uncertain and could adversely affect our consolidated financial results.

We are, and in the future may become, a party to a variety of legal proceedings. Litigation is subject to many uncertainties, and we cannot predict the outcome of individual matters with certainty. It is possible that the final resolution of some of the matters in which we are involved could result in additional material payments substantially in excess of established reserves or in terms that could require that we 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 our ability to take certain desired actions or the denial of needed permits, licenses or regulatory authority to conduct our business, including the siting or permitting of facilities. Any of these outcomes could have a material adverse effect on our consolidated financial results.

The ownership and operation of power generating facilities and transmission lines on federal or Native American lands could result in uncertainty related to continued leaseholds, easements and rights-of-way, which could have a significant impact on our business.

Certain portions of the Company's generating facilities and transmission lines that carry power from these facilities are located on federal or Native American lands pursuant to leases, easements or rights-of-way that are effective for specified periods. The Company is currently unable to predict the outcome of discussions with the federal government, the appropriate Native American tribes, the tribes' governing bodies, or the United States Bureau of Indian Affairs with respect to future arrangements for these leases, easements and rights-of-way, or grants of additional land rights for future Company projects.

BHE could exercise control over us in a manner that would benefit BHE to the detriment of our creditors.

BHE, through its subsidiary, owns all of our common stock and has control over all decisions requiring shareholder approval, including the election of our directors. In circumstances involving a conflict of interest between BHE and our creditors, BHE could exercise its control in a manner that would benefit BHE to the detriment of our creditors.

Our business operations and financial results could be adversely affected by our inability to realize, or delay in realizing, anticipated benefits or regulatory commitments relating to the BHE Merger.

The BHE Merger may cause an interruption of, or loss of momentum in, the usual activities of our business. The diversion of management's attention, changes in personnel and business methods, and any delays or difficulties encountered in connection with the integration of our operations could adversely affect our business and financial results and could impair our ability to realize the anticipated benefits of the transaction, or to meet regulatory commitments relating to the transaction.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

The Company's properties consist of the physical assets necessary to support its electricity business, which include electric generation, transmission and distribution facilities. In addition to these physical assets, the Company has rights-of-way and water rights that enable the Company to utilize its facilities. It is the opinion of the Company's management that the principal depreciable properties owned by the Company are in good operating condition and are well maintained. Substantially all of the Company's property in Nevada is subject to the lien of the Company's General and Refunding Mortgage Indenture filed as an Exhibit to this Form 10-K. For additional information regarding the Company's properties, refer to Item 1 of this Form 10-K and Notes 4 and 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

The right to construct and operate the Company's transmission and distribution facilities across certain property was obtained in most circumstances through negotiations and, where necessary, through the exercise of the power of eminent domain. The Company continues to have the power of eminent domain in Nevada, but it does not have the power of eminent domain with respect to governmental or Native American tribal lands.

With respect to real property, each of the facilities fall into two basic categories: (1) parcels that are owned in fee, such as certain of the Company's electricity generating facilities and substations; and (2) parcels where the interest derives from leases, easements, rights-of-way, permits, franchises or licenses from landowners or governmental authorities, or from prescription, permitting the use of such land for the construction, operation and maintenance of the generation and transmission and distribution facilities. Subject to litigation or claims disclosed in Note 16 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K, the Company believes that it has satisfactory title or interest to all of the real property making up its respective facilities in all material respects.

Item 3. Legal Proceedings

The Company is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. The Company does not believe that such normal and routine litigation will have a material 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. Refer to Note 16 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for information regarding legal proceedings.

Item 4. Mine Safety Disclosures

None.

PART II

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

All of the Company's common stock is held by its parent company, NV Energy, which is an indirect, wholly owned subsidiary of BHE.

The Company declared and paid dividends to NV Energy of $230 million in 2014 and $178 million in 2013.

Item 6. Selected Financial Data

The following tables set 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 historical consolidated financial data has been derived from the Company's audited historical Consolidated Financial Statements and notes thereto (in millions).

	Years Ended December 31,				
	2014	**2013**	**2012**	**2011**	**2010**
Consolidated Statement of Operations Data:					
Operating revenue	$ 2,337	$ 2,092	$ 2,145	$ 2,054	$ 2,252
Operating income	541	435	602	444	467
Net income	227	145	258	133	186

	As of December 31,				
	2014	**2013**	**2012**	**2011**	**2010**
Consolidated Balance Sheet Data:					
Total assets	$ 8,935	$ 8,835	$ 8,641	$ 8,443	$ 8,302
Long-term debt, including current maturities	3,576	3,577	3,337	3,460	3,578
Shareholder's equity	2,888	2,890	2,922	2,849	2,761

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

General

The Company'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. The Company 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 the Company. 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 the Company.

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

Results of Operations

Net income for the year ended December 31, 2014 was $227 million, an increase of $82 million, or 57% compared to 2013. Net income increased primarily due to $52 million in merger-related expense in 2013; $31 million of impairment charges in 2013 for certain assets not in rates; lower costs associated with major outages, planned maintenance and other generating costs; a one-time bill credit of $15 million to retail customers recorded in 2013 in connection with the BHE Merger; and disallowance by the PUCN of energy efficiency implementation revenues in 2013 due to the Company earning in excess of its authorized rate of return in 2012; partially offset by $29 million of impairment charges in 2014 for certain assets not in rates and regulatory amortizations.

Net income for the year ended December 31, 2013 was $145 million, a decrease of $113 million, or 44% compared to 2012. Net income decreased primarily due to $52 million in merger-related expense in 2013, $31 million of impairment charges in 2013 for certain assets not in rates, a one-time bill credit of $15 million to retail customers in 2013 in connection with the BHE Merger, costs associated with litigation, disallowance by the PUCN of energy efficiency implementation revenues in 2013 due to the Company earning in excess of its authorized rate of return in 2012, decrease in revenue due to usage and lower energy efficiency implementation revenue.

Operating revenue and cost of fuel, energy and capacity are key drivers of the Company's results of operations as they encompass retail and wholesale electricity revenue and the direct costs associated with providing electricity to customers. The Company believes that a discussion of gross margin, representing operating revenue less cost of fuel, energy and capacity, is therefore meaningful. A comparison of the Company's key operating results is as follows:

A comparison of key results related to gross margin for the years ended December 31 is as follows:

	2014	2013	Change		2013	2012	Change	
Gross margin (in millions):								
Operating revenue	$ 2,337	$ 2,092	$ 245	12 %	$ 2,092	$ 2,145	$ (53)	(2)%
Cost of fuel, energy and capacity	1,076	835	241	29	835	813	22	3
Gross margin	$ 1,261	$ 1,257	$ 4	—	$ 1,257	$ 1,332	$ (75)	(6)
GWh sold:								
Residential	8,923	9,012	(89)	(1)%	9,012	9,098	(86)	(1)%
Commercial	4,489	4,426	63	1	4,426	4,500	(74)	(2)
Industrial	7,486	7,533	(47)	(1)	7,533	7,666	(133)	(2)
Other	211	212	(1)	—	212	217	(5)	—
Total retail	21,109	21,183	(74)	—	21,183	21,481	(298)	(1)
Wholesale	20	36	(16)	(44)	36	61	(25)	(41)
Total GWh sold	21,129	21,219	(90)	—	21,219	21,542	(323)	(1)
Average number of retail customers (in thousands):								
Residential	770	754	16	2 %	754	746	8	1 %
Commercial	102	103	(1)	(1)	103	101	2	2
Industrial	2	2	—	—	2	2	—	—
Total	874	859	15	2	859	849	10	1
Average revenue per MWh:								
Retail	$ 108.90	$ 97.62	$ 11.28	12 %	$ 97.62	$ 98.11	$ (0.49)	— %
Heating degree days	1,306	1,887	(581)	(31)%	1,887	1,659	228	14 %
Cooling degree days	3,970	3,766	204	5 %	3,766	4,032	(266)	(7)%
Sources of energy (GWh)(1):								
Coal	4,422	2,900	1,522	52 %	2,900	2,059	841	41 %
Natural gas	12,590	14,360	(1,770)	(12)	14,360	14,423	(63)	—
Other	15	33	(18)	(55)	33	13	20	154
Total energy generated	17,027	17,293	(266)	(2)	17,293	16,495	798	5
Energy purchased	5,424	4,748	676	14	4,748	5,806	(1,058)	(18)
Total	22,451	22,041	410	2	22,041	22,301	(260)	(1)
Average cost of energy per MWh:								
Energy generated(2)	$ 36.68	$ 21.82	$ 14.86	68 %	$ 21.82	$ 20.60	$ 1.22	6 %
Energy purchased	$ 83.27	$ 96.42	$ (13.15)	(14)%	$ 96.42	$ 81.42	$ 15.00	18 %

(1) GWh amounts are net of energy used by the related generating facilities.

(2) The average cost per MWh of energy generated includes the cost of fuel and deferrals associated with the generating facilities and does not include other costs.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

Gross margin increased $4 million for 2014 compared to 2013 primarily due to:

- $15 million due to a one-time bill credit to retail customers in connection with the BHE Merger in 2013;
- $13 million due to customer growth;
- $11 million in transmission revenue primarily due to ON Line being placed in-service in December 2013; and

The increase was partially offset by:

- $18 million in lower residential customer usage in 2014 and
- $14 million in lower energy efficiency program rate revenue, which is offset in operating and maintenance expense.

Operating and maintenance decreased $50 million, or 11%, for 2014 compared to 2013 primarily due to $31 million of impairment charges in 2013 for certain assets not in rates; lower costs associated with major outages, planned maintenance and other generating costs; energy efficiency program costs, which are fully recovered in operating revenue; an $11 million disallowance by the PUCN of energy efficiency implementation revenues in 2013 due to the Company earning in excess of its authorized rate of return in 2012 (including carrying charges); and compensation costs. The decrease is partially offset by $29 million of impairment charges in 2014 for certain assets not in rates and regulatory amortizations.

Depreciation and amortization decreased $3 million, or 1%, for 2014 compared to 2013 primarily due to regulatory amortizations.

Property and other taxes increased $3 million, or 8%, for 2014 compared to 2013 primarily due to an increase in franchise taxes and an increase in property tax assessed value.

The Company incurred costs totaling $52 million in 2013 related to the BHE Merger, consisting of amounts payable under NV Energy's accelerated vesting and stock compensation under NV Energy's long-term incentive plan of $18 million; change in control policy of $15 million; investment banker fees paid by NV Energy of $15 million and legal and other expenses.

Other income (expense) is favorable $12 million, or 6%, for 2014 compared to 2013 as a result of using cash on hand to repay existing debt in July and December 2013, $8 million gain on sale of property and stock, higher net interest earned on regulatory items and lower amortization of debt expenses, partially offset by lower allowance for debt and equity funds used during construction due to assets placed in-service, including ON Line being placed in-service December 2013.

Income tax expense increased $36 million, or 38%, for 2014 compared to 2013 due to higher income before income tax expense. The effective tax rate was 36% in 2014 and 39% for 2013. The decrease in the effective tax rate is due to the effects of certain non-deductible merger related costs in 2013.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Gross margin decreased $75 million, or 6%, for 2013 compared to 2012 primarily due to:

- $46 million in lower energy efficiency program rate revenues, which is offset in operating and maintenance expense;
- $18 million in lower usage, primarily due to a decrease in cooling degree days during the summer;
- $15 million one-time bill credit to retail customers in connection with the BHE Merger in 2013; and
- $10 million in lower energy efficiency implementation revenue.

The decrease in gross margin was partially offset by:

- $8 million due to customer growth.

Operating and maintenance increased $32 million, or 8%, for 2013 compared to 2012 primarily due to $31 million of impairment charges related to the recovery of certain assets not in rates, an increase in costs associated with litigation, disallowance by the PUCN of energy efficiency implementation revenues due to the Company earning in excess of its authorized rate of return in 2012 (including carrying charges), increased maintenance and regulatory expenses and canceled projects written-off. This increase was partially offset by decreased energy efficiency program costs of $46 million, which are fully recovered in operating revenue.

Depreciation and amortization increased $7 million, or 3%, for 2013 compared to 2012 primarily due to higher plant in-service and software amortizations.

The Company incurred costs totaling $52 million in 2013 related to the BHE Merger, consisting of amounts payable under NV Energy's accelerated vesting and stock compensation under NV Energy's long-term incentive plan of $18 million; change in control policy of $15 million; investment banker fees paid by NV Energy of $15 million and legal and other expenses.

Other income (expense) decreased $10 million, or 5%, for 2013 compared to 2012 primarily due to a decrease in interest expense.

Income tax expense decreased $44 million, or 32%, for 2013 compared to 2012 due to lower income before income tax expense. The effective tax rate was 39% for 2013 and 35% for 2012. The increase in the effective tax rate is due to the effects of certain non-deductible merger related costs and adjustments due to finalization of the tax audit in 2012.

Liquidity and Capital Resources

As of December 31, 2014, the Company's total net liquidity was $620 million as follows (in millions):

Cash and cash equivalents	$	220
Credit facilities[1]		400
Less:		
Short-term debt		—
Letters of credit and tax exempt bond support		—
Net credit facilities		400
Total net liquidity	$	620
Credit facilities:		
Maturity dates		March 2018
Largest single bank commitment as a % of total credit facilities		12.5%

(1) Refer to Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding the Company's credit facility.

In January 2015, the Company issued a notice of redemption to the bondholders for its $250 million, 5.875% Series L General and Refunding Mortgage Securities and redeemed the aggregate principal amount outstanding of $250 million at 100% of the principal amount plus accrued interest with the use of cash on hand and short-term borrowings of $75 million.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2014 and 2013 were $704 million and $548 million, respectively. The change was primarily due to lower deferred energy refunded to customers, higher collections for energy costs, lower payments for merger costs and lower compensation payments, partially offset by lower collections from customers for conservation and renewable programs, payment in 2014 of the bill credit to customers as a result of the BHE merger, and higher coal purchases and generation inventory resulting from the acquisition of natural gas fueled generating facilities.

Net cash flows from operating activities for the years ended December 31, 2013 and 2012 were $548 million and $702 million, respectively. The change was primarily due to lower collections of energy costs resulting from higher fuel costs, lower collection of energy efficiency program rate costs, timing of payments for energy and lower customer usage, partially offset by lower coal purchases and lower spending on renewable energy programs.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2014 and 2013 were $(371) million and $(216) million, respectively. The change was primarily due to the acquisition of the Las Vegas and Sun Peak Generating Stations.

Net cash flows from investing activities for the years ended December 31, 2013 and 2012 were $(216) million and $(245) million, respectively. The change was primarily due to lower capital expenditures at the Goodsprings, Reid Gardner, Lenzie and Harry Allen Generating Stations, partially offset by the payment of $48 million related to the terminated co-ownership arrangement with California Department of Water Resources for Unit 4 of the Reid Gardner Generating Station.

Financing Activities

Net cash flows from financing activities for the years ended December 31, 2014 and 2013 were $(239) million and $(407) million, respectively. The change was primarily due to lower repayments of long-term debt, partially offset by higher dividends paid to NV Energy.

Net cash flows from financing activities for the years ended December 31, 2013 and 2012 were $(407) million and $(322) million, respectively. The change was primarily due to higher proceeds from the issuance of long-term debt and lower repayments of long-term debt. Repayments consisted of the following:

- In July 2013, the Company repaid the aggregate principal amount outstanding of $98 million Clark County Industrial Development Refunding Revenue Bonds, Series 2000A at 100% of the principal amount plus accrued interest with the use of cash on hand.
- In November 2013, the Company repaid the aggregate principal amount outstanding of $125 million 7.375% Series U General and Refunding Mortgage Securities at 100.7% of the principal amount plus accrued interest with the use of cash on hand.

Ability to Issue Debt

The Company's ability to issue debt is primarily impacted by its financing authority from the PUCN. As of December 31, 2014, the Company has financing authority from the PUCN consisting of the ability to: (1) issue additional long-term debt securities of up to $725 million; (2) refinance up to $423 million of long-term debt securities; and (3) maintain a revolving credit facility of up to $1.3 billion. The Company's revolving credit facility contains a financial maintenance covenant which the Company was in compliance with as of December 31, 2014. In addition, certain financing agreements contain covenants which are currently suspended as the Company's senior secured debt is rated investment grade. However, if the Company's senior secured debt ratings fall below investment grade by either Moody's Investor Service or Standard & Poor's, the Company would be subject to limitations under these covenants.

Ability to Issue General and Refunding Mortgage Securities

To the extent the Company 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, the Company'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 the Company's indenture.

The Company's indenture creates a lien on substantially all of the Company's properties in Nevada. As of December 31, 2014, $3.5 billion of the Company's assets were pledged. The Company had the capacity to issue $2.2 billion of additional general and refunding mortgage securities as of December 31, 2014 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. The Company also has the ability to release property from the lien of the Company's indenture on the basis of net property additions, cash or retired bonds. To the extent the Company releases property from the lien of the Company's indenture, it will reduce the amount of securities issuable under the indenture.

Future Uses of Cash

Capital Expenditures

The Company has significant future capital requirements. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, changes in environmental and other rules and regulations; impacts to customers' rates; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital. Prudently incurred expenditures for compliance-related items such as pollution control technologies, replacement generation and associated operating costs are generally incorporated into the Company'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		
	2012	2013	2014	2015	2016	2017
Generation development	$ 90	$ 81	$ 201	$ 161	$ 148	$ 732
Distribution	68	57	107	117	96	100
Transmission system investment	41	50	19	33	23	8
Other	46	45	44	47	19	23
Total	$ 245	$ 233	$ 371	$ 358	$ 286	$ 863

The Company estimates that it will spend approximately $1.5 billion on capital projects over the next three years, excluding non-cash equity AFUDC and other non-cash items.

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, 2014 (in millions):

	Payments Due by Periods				
	2015	2016 - 2017	2018 - 2019	2020 and After	Total
Long-term debt	$ 250	$ 210	$ 1,323	$ 1,291	$ 3,074
Interest payments on long-term debt(1)	184	335	248	1,405	2,172
Capital leases, including interest(2),(3)	14	24	25	72	135
ON Line financial lease, including interest(2)	44	88	87	857	1,076
Fuel and capacity contract commitments(1)	607	810	579	3,058	5,054
Fuel and capacity contract commitments (not commercially operable)(1)	65	159	169	1,883	2,276
Construction commitments(1)	42	—	—	—	42
Operating leases and easements(1)	9	13	14	52	88
Asset retirement obligations	14	17	25	53	109
Maintenance, service and other contracts(1)	39	76	74	161	350
Total contractual cash obligations	$ 1,268	$ 1,732	$ 2,544	$ 8,832	$ 14,376

(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.

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 7) and uncertain tax positions (Note 12), which have not been included in the above table because the amount and timing of the cash payments are not certain. Additionally, refer to Note 16 for equity commitments related to solar projects currently under construction. 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

The Company is subject to comprehensive regulation. In addition to the discussion contained herein regarding regulatory matters, refer to Item 1 of this Form 10-K for further discussion regarding the Company's general regulatory framework.

State Regulatory Matters

The PUCN's final order approving the BHE Merger stipulated that the Company will not seek recovery of any lost revenue for calendar year 2014 in an amount that exceeds 50% of the lost revenue that the Company could otherwise request. In February 2014, the Company filed an application with the PUCN to reset the EEIR and energy efficiency program rates. In June 2014, the PUCN accepted a stipulation to adjust the EEIR, as of July 1, 2014, to collect 50% of the estimated lost revenue that the Company would otherwise be allowed to recover for the 2014 calendar year. The EEIR was effective from July through December 2014 and will reset on January 1, 2015 and remain in effect through September 2015. To the extent the Company's earned rate of return exceeds the rate of return used to set base general rates, the Company is required to refund to customers EEIR revenue collected. As a result, the Company has deferred recognition of EEIR revenue collected and has recorded a liability of $11 million, which is included in current regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2014.

General Rate Case

In May 2014, the Company filed a general rate case with the PUCN. In July 2014, the Company made its certification filing, which requested incremental annual revenue relief in the amount of $38 million, or an average price increase of 2%. In October 2014, the Company reached a settlement agreement with certain parties agreeing to a zero increase in the revenue requirement. In October 2014, the PUCN issued an order in the general rate case filing that accepted the settlement. The order provides for increases in the fixed-monthly service charge for customers with a corresponding decrease in the base tariff general rate effective January 1, 2015. As a result of the order, the Company recorded $15 million in asset impairments related to property, plant and equipment and $5 million of regulatory asset impairments, which are included in operating and maintenance on the Consolidated Statements of Operations for the year ended December 31, 2014. Additionally, the Company recorded a $5 million gain in other, net on the Consolidated Statement of Operations for the year ended December 31, 2014 related to the disposition of property. In October 2014, a party filed a petition for reconsideration of the PUCN order. In November 2014, the PUCN granted the petition for reconsideration and reaffirmed the order issued in October 2014.

Emissions Reduction and Capacity Replacement Plan

In May 2014, the Company filed its Emissions Reduction Capacity Replacement Plan ("ERCR Plan") in compliance with Senate Bill No. 123 ("SB 123") enacted by the 2013 Nevada Legislature. The filing proposed, among other items, the retirement of Reid Gardner Generating Station units 1, 2 and 3 in 2014 and unit 4 in 2017; the elimination of the Company's ownership interest in Navajo Generating Station in 2019; and a plan to replace the generating capacity being retired, as required by SB 123. The ERCR Plan includes the issuance of requests for proposals for 300 MW of renewable energy to be issued between 2014 and 2016; the acquisition of a 272-MW natural gas co-generating facility in 2014; the acquisition of a 210-MW natural gas peaking facility in 2014; the construction of a 15-MW solar photovoltaic facility expected to be placed in-service in 2015; and the construction of a 200-MW solar photovoltaic facility expected to be placed in-service in 2016. In the second quarter of 2014, the Company executed various contractual agreements to fulfill the proposed ERCR Plan, which are subject to the PUCN approval. The PUCN issued an order dated October 28, 2014 removing the 200-MW solar photovoltaic facility proposed by the Company from the ERCR Plan but accepting the remaining requests. The Company filed a petition for reconsideration, but in December 2014, the PUCN upheld the original order from October 2014 with respect to material matters. In December 2014, the Company filed its acceptance of the modifications to the ERCR Plan.

Advanced Metering Infrastructure

In October 2014, the PUCN issued an order directing the Company to provide information relating to failures in certain remote disconnect/reconnect electric meters the Company has installed after media reports were published that electric meter failures may have resulted in fire events. The Company completed an internal review in response to this and other federal, state and local inquiries relating to these events. The information compiled and submitted indicates that no fire has resulted from the remote disconnect/reconnect electric meters. Additionally, in October 2014, the Nevada State Fire Marshal issued a report concluding that the incidents of electric arcing fires continue to decrease in Nevada and at this time there is no statewide fire problem related to the replacement of electric meters. In December 2014, the Company filed the requested information with the PUCN. Management cannot assess or predict the outcome of these inquires at this time.

Federal Regulatory Matters

2013 FERC Transmission Rate Case

In May 2013, the Company, along with Sierra Pacific, filed an application with the FERC to establish single system transmission and ancillary service rates. The combined filing requested incremental rate relief of $17 million annually to be effective January 1, 2014. In August 2013, the FERC granted the companies' request for a rate effective date of January 1, 2014 subject to refund, and set the case for hearing or settlement discussions. On January 1, 2014, the Company implemented the filed rates in this case subject to refund as set forth in the FERC's order.

In September 2014, the Company, along with Sierra Pacific, filed an unopposed settlement offer with the FERC on behalf of NV Energy and the intervening parties providing rate relief of $4 million. The settlement offer would resolve all outstanding issues related to this case. In addition, a preliminary order from the administrative law judge granting the motion for interim rate relief was issued, which authorizes the Company to institute the interim rates effective September 1, 2014, and begin billing transmission customers under the settlement rates for service provided on and after that date. In January 2015, the FERC approved the settlement and refunds will be processed in 2015. As of December 31, 2014, the Company accrued $7 million for amounts subject to rate refund, which is included in other current liabilities on the Consolidated Balance Sheets.

Environmental Laws and Regulations

The Company 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 the Company's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by the EPA and various state and local agencies. The Company believes it is in material compliance with all applicable laws and regulations, although many are subject to interpretation that may ultimately be resolved by the courts. Refer to "Liquidity and Capital Resources" for discussion of the Company's forecasted environmental-related capital expenditures.

Senate Bill 123 Compliance

In June 2013, SB 123 was signed into law. Among other things, SB 123 and regulations thereunder require the Company to file with the PUCN an emission reduction and capacity replacement plan by May 1, 2014. The plan must provide 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 must set 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 the Company. Given the PUCN may recommend and/or approve variations to the Company's resource plans relative to requirements under SB 123, the specific impacts of SB 123 on the Company cannot be determined. Refer Item 7 "Regulatory Matters" of this Form 10-K for additional information regarding SB 123.

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 Company's operations are described below.

National Ambient Air Quality Standards

Under the authority of the Clean Air Act, the EPA sets minimum national ambient air quality standards for six principal pollutants, consisting of carbon monoxide, lead, nitrogen 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.

In November 2014, the EPA released a new proposal to strengthen the national ambient air quality standard for ground level ozone from the current level of 75 parts per billion to a level between 65 and 70 parts per billion. Review or revision is required to be complete by October 2015. Until the standards' review or revision is complete, the EPA is proceeding with implementation of the 2008 ozone standards. In December 2012, the EPA approved Nevada's request to redesignate 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 the Company's Clark, Sun Peak, Las Vegas, Lenzie, Silverhawk, Harry Allen, Higgins, Goodsprings and Reid Gardner generating facilities. However, until such time as a new standard is implemented or Clark County is classified as nonattainment for the 2008 standard, 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. Although the EPA's July 2013 designations did not impact the Company's 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.

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 Company operates generating facilities have been classified as "unclassifiable/attainment." Unless additional monitoring suggests otherwise, the Company does not anticipate that any impacts of the revised standard will be significant.

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 Company 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 rule, MATS, was published in the Federal Register in February 2012, with an effective date of April 16, 2012, and requires that new and existing coal-fueled generating facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. Existing sources are required to comply with the new standards by April 16, 2015. Individual sources may be granted up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls or for transmission system reliability reasons. The Company believes that its emissions reduction projects completed to date are consistent with the EPA's MATS and will support the Company's ability to comply with the final rule's standards for acid gases and non-mercury metallic hazardous air pollutants. Actions the Company will take in order to comply with SB 123, including with respect to the retirement or elimination of certain coal generating capacity beginning in 2014, will further reduce mercury emissions and other air pollutants consistent with the EPA's MATS.

Incremental costs to install and maintain emissions control equipment at the Company's coal-fueled generating facilities and any resulting shut down of what have traditionally been low cost coal-fueled generating facilities will likely increase the cost of providing service to customers. Numerous lawsuits have been filed in the United States Court of Appeals for the District of Columbia Circuit ("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. The outcome of the United States Supreme Court's decision is uncertain and until the court renders its decision or otherwise implements a stay of the MATS requirements, the Company is proceeding to fulfill its legal obligations to comply with the MATS.

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"). Certain of the Company'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.

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

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

Until the EPA takes final action and decisions have been made on each appeal, the Company cannot fully determine the impacts of the Regional Haze Rule on the Navajo Generating facility.

New Source Review

Under existing New Source Review ("NSR") provisions of the Clean Air Act, any facility that emits regulated pollutants is required to obtain a permit from the EPA or a state regulatory agency prior to (a) beginning construction of a new major stationary source of a regulated pollutant or (b) making a physical or operational change to an existing stationary source of such pollutants that increases certain levels of emissions, unless the changes are exempt under the regulations (including routine maintenance, repair and replacement of equipment). In general, projects subject to NSR regulations require pre-construction review and permitting under the Prevention of Significant Deterioration ("PSD") provisions of the Clean Air Act. Under the PSD program, a project that emits threshold levels of regulated pollutants must undergo an analysis to determine the best available control technology and evaluate the most effective emissions controls after consideration of a number of factors. Violations of NSR regulations, which may be alleged by the EPA, states, environmental groups and others, potentially subject a company to material fines and other sanctions and remedies, including installation of enhanced pollution controls and funding of supplemental environmental projects.

Numerous changes have been proposed to the NSR rules and regulations over a period of years. In addition to the proposed changes, differing interpretations by the EPA and the courts create risk and uncertainty for entities when seeking permits for new projects and installing emissions controls at existing facilities under NSR requirements. The Company monitors these changes and interpretations to ensure permitting activities are conducted in accordance with the applicable requirements.

As part of an industry-wide investigation to assess compliance with the NSR and PSD provisions, the EPA has requested information and supporting documentation from numerous utilities regarding their capital projects for various coal-fueled generating facilities. A NSR enforcement case against an unrelated utility has been decided by the United States Supreme Court, holding that an increase in the annual emissions of a generating facility, when combined with a modification (i.e., a physical or operational change), may trigger NSR permitting.

In October 2011, the Company received a request from the EPA Region 9 pursuant to Section 114 of the Clean Air Act for information regarding current and historic operations and capital projects for the Company's Reid Gardner coal-fueled generating facility. The Company submitted its response to the EPA during the first quarter of 2012. The Company cannot predict the outcome of this matter at this time.

Climate Change

While significant measures to regulate GHG emissions at the federal level were considered by the United States Congress in 2010, comprehensive climate change legislation has not been adopted. In June 2013, President Obama issued a Climate Action Plan, which, among other things, required the EPA to address GHG emissions from new, modified and existing fossil-fueled generating facilities under the Clean Air Act. Regulation of GHG emissions has proceeded under various provisions of the Clean Air Act since the EPA's December 2009 findings that GHG emissions threaten public health and welfare.

GHG Tailoring Rule

In May 2010, the EPA finalized the GHG "Tailoring Rule" requiring new or modified sources of GHG emissions with increases of 75,000 or more tons per year of total GHG to determine the best available control technology for their GHG emissions beginning in January 2011. New or existing major sources are also subject to Title V operating permit requirements for GHG. Beginning July 1, 2011 through June 30, 2013, new construction projects that emit GHG emissions of at least 100,000 tons per year and modifications of existing facilities that increase GHG emissions by at least 75,000 tons per year became subject to permitting requirements. While the final rule also required facilities that were previously not subject to Title V permitting requirements to obtain Title V permits if they emit at least 100,000 tons per year of carbon dioxide equivalents, litigation over the Tailoring Rule resulted in a decision by the United States Supreme Court in June 2014 that the EPA could not utilize the Tailoring Rule to impose GHG permitting requirements on sources not otherwise subject to Clean Air Act permitting provisions. That decision did not impact the Company’s sources that are already subject to Clean Air Act permitting. To date, permitting authorities implementing the GHG Tailoring Rule have included efficiency improvements to demonstrate compliance with best available control technology for GHG, as well as requiring emissions limits for GHGs in permits, which have not had a material impact on the Company's consolidated financial results.

GHG Performance Standards

Under the Clean Air Act, the EPA may establish emissions standards that reflect the degree of emissions reductions achievable through the best technology that has been demonstrated, taking into consideration the cost of achieving those reductions and any non-air quality health and environmental impact and energy requirements. The EPA entered into a settlement agreement with a number of parties, including certain state governments and environmental groups, in December 2010 to promulgate emissions standards covering GHG. In April 2012, the EPA proposed new source performance standards for new fossil-fueled generating facilities that would limit emissions of carbon dioxide to 1,000 pounds per MWh. As part of his Climate Action Plan, President Obama announced a national climate change strategy and issued a presidential memorandum requiring the EPA to issue a re-proposed GHG new source performance standard for fossil-fueled generating facilities by September 2013. The September 2013 GHG new source performance standards released by the EPA set different standards for coal-fueled and natural gas-fueled generating facilities. The proposed standard for natural gas-fueled generating facilities considers the size of the unit and the electricity sent to the grid from the unit, establishing a standard of 1,000 to 1,100 pounds of carbon dioxide per MWh. The standard proposed for coal-fueled generating facilities is 1,100 pounds of carbon dioxide per MWh on an annual basis or 1,000 to 1,050 pounds of carbon dioxide per MWh averaged over a seven-year period, both of which would require partial carbon capture and sequestration. The proposed standards were published in the Federal Register January 8, 2014, and the public comment period closed in May 2014. Any new fossil-fueled generating facilities constructed by the Company will be required to meet the GHG new source performance standards, which are expected to be finalized in the summer of 2015.

In June 2014, the EPA released proposed regulations to address GHG emissions from existing fossil-fueled generating facilities, referred to as the Clean Power Plan, under Section 111(d) of the Clean Air Act. The EPA's proposal calculated state-specific emission rate targets to be achieved based on four building blocks that it determined were the "Best System of Emission Reduction." The four building blocks include: (a) a 6% heat rate improvement from coal-fueled generating facilities; (b) increased utilization of existing combined-cycle natural gas-fueled generating facilities to 70%; (c) increased deployment of renewable and non-carbon generating resources; and (d) increased energy efficiency. Under the EPA's proposal, states may utilize any measure to achieve the specified emission reduction goals, with an initial implementation period of 2020-2029 and the final goal to be achieved by 2030. When fully implemented, the proposal is expected to reduce carbon dioxide emissions in the power sector to 30% below 2005 levels by 2030. The public comment period closed December 1, 2014 and the final guidelines are scheduled to be issued in the summer of 2015. States are required to submit implementation plans by June 2016, but they may request an extension to June 2017, or June 2018 if they plan to participate in a regional compliance program. The impacts of the proposal on the Company cannot be determined until the EPA finalizes the proposal and the states develop their implementation plans. The Company has 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 November 2014, President Obama announced the United States and China had reached a climate change agreement under which the United States intends to achieve an economy-wide target of reducing its emissions by 26% to 28% below 2005 levels in 2025 and China would peak its GHG emissions around 2030 and increase the share of non-fossil fuels in primary energy consumption to 20% by 2030.

While the discussion continues at the federal and international level over the direction of climate change policy, several states have continued to implement state-specific laws or regional initiatives to report or mitigate GHG emissions. In addition, governmental, non-governmental and environmental organizations have become more active in pursuing climate change related litigation under existing laws.

New federal, regional, state and international accords, legislation, regulation, or judicial proceedings limiting GHG emissions could have a material adverse impact on the Company, the United States and the global economy. Companies and industries with higher GHG emissions, such as utilities with significant coal-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 Company 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 Company's 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, could vary widely, from highly localized to worldwide, and the extent to which a utility's operations may be affected is uncertain. Climate change may cause physical and financial risk through, among other things, sea level rise, changes in precipitation and extreme weather events. Consumer demand for energy may increase or decrease, based on overall changes in weather and as customers promote lower energy consumption through the continued use of energy efficiency programs or other means. Availability of resources to generate electricity, such as water for hydroelectric production and cooling purposes, may also be impacted by climate change and could influence the Company's existing and future electricity 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.

GHG Litigation

The Company closely monitors ongoing environmental litigation. 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. An adverse ruling in similar cases would likely result in increased regulation and costs for GHG emitters, including the Company's generating facilities.

Renewable Portfolio Standards

Since 1997, the Company has been required to comply with a RPS. Current law requires the Company to meet 18% of its 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. The Company is in compliance with these requirements.

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). The Company does not utilize once-through cooling water intake or discharge structures at any of its generating facilities. All of the Company's generating stations are designed to have either minimal or zero discharge; therefore, they are not expected to be impacted by the §316(b) final rule.

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

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

Coal Combustion Byproduct Disposal

In May 2010, the EPA released a proposed rule to regulate the management and disposal of coal combustion byproducts, presenting two alternatives to regulation under the Resource Conservation and Recovery Act ("RCRA"). The public comment period closed in November 2010. The final rule was released by the EPA on December 19, 2014 and will be effective 180 days after it is published in the Federal Register. 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.

As defined by the final rule, the Company operates ten evaporative surface impoundments that are likely to fall within the definition of the final rule and one landfill that contains coal combustion byproducts. The Company is assessing the requirements of the final rule to determine the costs of compliance.

Other

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

- The federal Comprehensive Environmental Response, Compensation and Liability Act and similar state laws may require any current or former owners or operators of a disposal site, as well as transporters or generators of hazardous substances sent to such disposal site, to share in environmental remediation costs.

The Company expects to be allowed to recover the prudently incurred costs to comply with the environmental laws and regulations discussed above. The Company's 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 Company 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 Company has 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.

Collateral and Contingent Features

Debt of the Company is rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of the Company'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.

The Company 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. The Company'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, 2014, the applicable credit ratings from the three recognized credit rating agencies were investment grade. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of December 31, 2014, the Company would have been required to post $68 million of additional collateral. The Company's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors. Refer to Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for a discussion of the Company's collateral requirements specific to the Company's derivative contracts.

In July 2010, the President signed into law the Dodd-Frank Reform Act. The Dodd-Frank Reform Act reshapes financial regulation in the United States by creating new regulators, regulating markets and firms not previously regulated, and providing new enforcement powers to regulators. Virtually all major areas of the Dodd-Frank Reform Act are and have been subject to extensive rulemaking proceedings being conducted both jointly and independently by multiple regulatory agencies, many of which have been completed and others that have not yet been finalized.

The Company is a party to derivative contracts, including over-the-counter derivative contracts. The Dodd-Frank Reform Act provides for extensive new regulation of over-the-counter derivative contracts and certain market participants, including imposition of position limits, mandatory clearing, exchange trading, capital, margin, reporting, recordkeeping and business conduct requirements. Many of these requirements are primarily for "swap dealers" and "major swap participants," but many of these also impose some requirements on almost all market participants, including the Company. The Dodd-Frank Reform Act provides certain exemptions from many of these requirements for commercial end-users when using derivatives to hedge or mitigate commercial risk of their businesses. The Company qualifies or believes it will qualify for many of these exemptions. The Company generally does not enter into over-the-counter derivative contracts for purposes unrelated to hedging or mitigating commercial risk and has determined that it is not a swap dealer or major swap participant. The outcome of pending and remaining Dodd-Frank Reform Act rulemaking proceedings cannot be predicted but requirements resulting from these proceedings could directly impact the Company or could have impacts to energy and other markets in general that could have an impact on the Company's consolidated financial results.

Inflation

Historically, overall inflation and changing prices in the economies where the Company operates has not had a significant impact on the Company's consolidated financial results. The Company operates under a cost-of-service based rate structure administered by the PUCN and the FERC. Under this rate structure, the Company is allowed to include prudent costs in its rates, including the impact of inflation after the Company experiences cost increases. Fuel and purchase power costs are recovered through a balancing account, minimizing the impact of inflation related to these costs. The Company 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 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 Company prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, the Company 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.

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 Company's ability to recover its 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 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 $1.1 billion and total regulatory liabilities were $366 million as of December 31, 2014. Refer to Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's regulatory assets and liabilities.

Derivatives

The Company is exposed to the impact of market fluctuations in commodity prices and interest rates. The Company is principally exposed to electricity, natural gas and coal market fluctuations primarily through the Company's obligation to serve retail customer load in its regulated service territory. The Company'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.

The Company has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business. The Company employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage its commodity price and interest 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, to mitigate the Company's exposure to interest rate risk. The Company does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices. Refer to Note 9 and 10 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's derivatives.

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 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. As of December 31, 2014, the Company's net derivative liability was valued primarily using 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. Interest rate swaps are valued using a financial model which utilizes observable inputs for similar instruments based primarily on market price curves. The determination of the fair value for derivative contracts not only includes counterparty risk, but also the impact of the Company's nonperformance risk on its liabilities, which as of December 31, 2014, had an immaterial impact to the fair value of its derivative contracts. As such, the Company 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, 2014, the Company had a net derivative liability of $30 million related to contracts where the Company uses internal models with significant unobservable inputs.

Classification and Recognition Methodology

The Company'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, 2014, the Company had $30 million recorded as a regulatory asset related to derivative contracts on the Consolidated Balance Sheets.

Impairment of Long-Lived Assets

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, 2014, 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.

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 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. 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 and local 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 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company'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 the Company is required to pass on to its customers are charged or credited directly to a regulatory asset or liability. As of December 31, 2014 and 2013, these amounts were recognized as regulatory assets of $156 million and $165 million, respectively, and regulatory liabilities of $3 million and $4 million, respectively, 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 $111 million as of December 31, 2014. 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

The Company's Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. The Company's significant market risks are primarily associated with commodity prices, interest rates and 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. The Company has established guidelines for credit risk management. Refer to Notes 2 and 9 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 exposed to the impact of market fluctuations in commodity prices and interest rates. The Company is principally exposed to electricity, natural gas and coal market fluctuations primarily through the Company's obligation to serve retail customer load in its regulated service territory. The Company'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. 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 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 the 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 the Company'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, 2014			
Total commodity derivative contracts	$ (25)	$ (29)	$ (21)
As of December 31, 2013			
Total commodity derivative contracts	$ (43)	$ (49)	$ (39)

The Company'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 the Company to earnings volatility. As of December 31, 2014, the Company recorded a net regulatory asset of $30 million related to the net derivative liability of $30 million.

Interest Rate Risk

The Company is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. 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 7 and 8 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, 2014 and 2013, the Company had short- and long-term variable-rate obligations totaling $76 million 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, 2014 and 2013.

Credit Risk

The Company 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 the Company's counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, the Company 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, the Company 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, the Company exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2014, the Company's aggregate credit exposure from energy related transactions totaled $37 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 (the "Company") as of December 31, 2014 and 2013, 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, 2014. These financial statements are the responsibility of the Company'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. 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 Nevada Power Company and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 27, 2015

NEVADA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions, except share data)

	As of December 31,	
	2014	**2013**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 220	$ 126
Accounts receivable, net	243	227
Inventories	88	73
Regulatory assets	57	81
Deferred income taxes	145	152
Other current assets	32	39
Total current assets	785	698
Property, plant and equipment, net	7,003	6,992
Regulatory assets	1,069	1,057
Other assets	78	88
Total assets	$ 8,935	$ 8,835
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 212	$ 240
Accrued interest	60	61
Accrued property, income and other taxes	30	29
Regulatory liabilities	40	74
Current portion of long-term debt	264	22
Customer deposits	55	58
Other current liabilities	36	22
Total current liabilities	697	506
Long-term debt	3,312	3,555
Regulatory liabilities	326	312
Deferred income taxes	1,414	1,298
Other long-term liabilities	298	274
Total liabilities	6,047	5,945
Commitments and contingencies (Note 16)		
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	583	586
Accumulated other comprehensive loss, net	(3)	(4)
Total shareholder's equity	2,888	2,890
Total liabilities and shareholder's equity	$ 8,935	$ 8,835

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,		
	2014	**2013**	**2012**
Operating revenue	$ 2,337	$ 2,092	$ 2,145
Operating costs and expenses:			
Cost of fuel, energy and capacity	1,076	835	813
Operating and maintenance	405	455	423
Depreciation and amortization	274	277	270
Property and other taxes	41	38	37
Merger-related	—	52	—
Total operating costs and expenses	1,796	1,657	1,543
Operating income	541	435	602
Other income (expense):			
Interest expense	(208)	(215)	(215)
Allowance for borrowed funds	1	6	5
Allowance for equity funds	1	8	7
Other, net	22	5	(3)
Total other income (expense)	(184)	(196)	(206)
Income before income tax expense	357	239	396
Income tax expense	130	94	138
Net income	$ 227	$ 145	$ 258

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, 2011	1,000	$ —	$ 2,308	$ 545	$ (4)	$ 2,849
Net income	—	—	—	258	—	258
Dividends declared	—	—	—	(184)	—	(184)
Other	—	—	—	—	(1)	(1)
Balance, December 31, 2012	1,000	—	2,308	619	(5)	2,922
Net income	—	—	—	145	—	145
Dividends declared	—	—	—	(178)	—	(178)
Other	—	—	—	—	1	1
Balance, December 31, 2013	1,000	—	2,308	586	(4)	2,890
Net income	—	—	—	227	—	227
Dividends declared	—	—	—	(230)	—	(230)
Other	—	—	—	—	1	1
Balance, December 31, 2014	1,000	$ —	$ 2,308	$ 583	$ (3)	$ 2,888

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,		
	2014	2013	2012
Cash flows from operating activities:			
Net income	$ 227	$ 145	$ 258
Adjustments to reconcile net income to net cash from operating activities:			
Loss on nonrecurring items	15	—	(4)
Depreciation and amortization	274	277	270
Deferred income taxes and amortization of investment tax credits	130	95	151
Allowance for equity funds	(1)	(8)	(7)
Amortization of deferred energy	79	(54)	(170)
Deferred energy	(44)	(105)	112
Amortization of other regulatory assets	47	89	88
Other, net	72	90	(25)
Changes in other assets and liabilities:			
Accounts receivable and other assets	(71)	(12)	3
Inventories	(15)	10	(5)
Accounts payable and other liabilities	(9)	21	31
Net cash flows from operating activities	704	548	702
Cash flows from investing activities:			
Capital expenditures	(410)	(267)	(288)
Contributions in aid of construction and customer advances	39	34	43
Proceeds from sale of asset	—	14	—
Other, net	—	3	—
Net cash flows from investing activities	(371)	(216)	(245)
Cash flows from financing activities:			
Proceeds from issuance of long-term debt, net of costs	—	—	132
Repayments of long-term debt	(9)	(229)	(270)
Dividends paid	(230)	(178)	(184)
Net cash flows from financing activities	(239)	(407)	(322)
Net change in cash and cash equivalents	94	(75)	135
Cash and cash equivalents at beginning of period	126	201	66
Cash and cash equivalents at end of period	$ 220	$ 126	$ 201

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

(1) Organization and Operations

Nevada Power Company, together with its subsidiaries (collectively, the "Company"), 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. The Company 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").

On December 19, 2013, the merger contemplated by the Agreement and Plan of Merger dated May 29, 2013 among BHE, Silver Merger Sub, Inc. ("Merger Sub"), BHE's wholly owned subsidiary, and NV Energy, whereby Merger Sub was merged into NV Energy and NV Energy became an indirect wholly owned subsidiary of BHE ("BHE Merger") was completed.

The transaction was approved by the board of directors of both NV Energy and BHE and the shareholders of NV Energy and received various regulatory approvals, including the Public Utilities Commission of Nevada ("PUCN"), subject to certain stipulations. The stipulations included, among others:

- A one-time bill credit to retail customers of the Company of $15 million credited to retail customers over one billing cycle beginning within 30 days of the close of the BHE Merger.
- BHE and NV Energy agreed to not seek recovery of the acquisition premium, transaction and transition costs associated with the BHE Merger from customers.
- NV Energy agreed that it will base any rate case filed in 2014 by the Company with a requested change in revenue requirement on a return on common equity not to exceed 10%.
- The Company will not seek to collect lost revenues as described in section 704.9524 of the Nevada Administrative Code for calendar year 2013 in 2014 rates, and will not seek collection of lost revenues in excess of 50% of what the Company could otherwise request for calendar year 2014 in 2015 rates. NV Energy also agreed to work cooperatively with PUCN staff and the Nevada Bureau of Consumer Protection ("BCP") to develop a legislative or administrative alternative to the current mechanism that would retain the objective of encouraging investment in energy efficiency and that is acceptable to NV Energy, PUCN staff and the BCP. NV Energy and the BCP also agree to work in good faith to have a legislative or administrative alternative adopted.
- Normal rate case rules and procedures apply to costs and revenues, and any under or over earnings will accrue to the Company until the next rate case filing after 2014, subject to specified adjustments for intercompany charges from BHE and its other subsidiaries as described in the PUCN Joint Application and the exclusion of the $15 million one-time bill credit from the test period. The commitment does not preclude parties from proposing any other adjustments to test year or certification period results.

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of the 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 impacts of acquisition accounting from the BHE Merger were not reflected on the Consolidated Financial Statements of the Company.

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

The Company prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, the Company 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.

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 Company's ability to recover its 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 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 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 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. The Company 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):

	2014	2013	2012
Beginning balance	$ 8	$ 8	$ 7
Charged to operating costs and expenses, net	14	15	15
Write-offs, net	(8)	(15)	(14)
Ending balance	$ 14	$ 8	$ 8

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 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. 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 cost of fuel, energy and capacity 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 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.

Inventories

Inventories consist mainly of materials and supplies totaling $58 million and $54 million as of December 31, 2014 and 2013, respectively, and fuel, which includes coal stocks, stored natural gas and fuel oil, totaling $30 million and $19 million as of December 31, 2014 and 2013, 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 PUCN.

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 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 the Company's various regulatory authorities. Depreciation studies are completed by the Company 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, 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, 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. The Company's AFUDC rate used during both 2014 and 2013 was 8.09%.

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 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.

Management's methodology to assess its legal obligation includes an inventory of assets by the Company's system and components and a review of rights-of-way and easements, regulatory orders, leases and federal, state and local environmental laws. Management identified legal obligations to retire generation plant assets specified in land leases for the Company'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. Additionally, management has determined evaporative ponds, dry ash landfills, fuel storage tanks, asbestos and oils treated with Poly Chlorinated Biphenyl have met the requirements for an ARO.

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. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2014, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Income Taxes

Berkshire Hathaway commenced including the Company in its United States federal income tax return on December 20, 2013 in connection with the BHE Merger. Prior to December 20, 2013, the Company filed a consolidated United States federal income tax return with NV Energy. Consistent with established regulatory practice, the Company'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 the Company is required to pass on to its customers are charged or credited directly to a regulatory asset or liability. As of December 31, 2014 and 2013, these amounts were recognized as regulatory assets of $156 million and $165 million, respectively, and regulatory liabilities of $3 million and $4 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 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 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. 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 and local 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.

Revenue Recognition

Revenue is recognized as electricity is delivered or services are provided. Revenue recognized includes billed and unbilled amounts. As of December 31, 2014 and 2013, unbilled revenue was $111 million and $103 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. 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.

The Company primarily buys energy and natural gas to satisfy its customer load requirements. Due to changes in retail customer load requirements, the Company may not take physical delivery of the energy or natural gas. The Company may sell the excess energy or natural gas to the wholesale market. In such instances, it is the Company's policy to record such sales net in cost of fuel, energy and capacity.

Unamortized Debt Premiums, Discounts and Financing Costs

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

Segment Information

The Company currently has one segment, which includes its regulated electric utility operations.

New Accounting Pronouncements

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

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

(3) Merger-Related Activities

On December 17, 2013, the PUCN approved the Joint Application related to the BHE Merger filed by BHE and NV Energy, subject to certain stipulations. The stipulations included, among others, a one-time bill credit to retail customers of the Company of $15 million credited to retail customers over one billing cycle beginning within 30 days of the close of the BHE Merger. The bill credit was included as a reduction to operating revenue on the Consolidated Statements of Operations for the year ended December 31, 2013.

The Company incurred costs totaling $52 million related to the BHE Merger, consisting of: (i) $15 million for amounts payable under NV Energy's change in control policy; (ii) $18 million for accelerated vesting and stock compensation under NV Energy's long-term incentive plan; (iii) $15 million for investment banker fees paid by NV Energy and (iv) $4 million for legal and other expenses. The costs were included in merger-related expenses on the Consolidated Statements of Operations for the year ended December 31, 2013.

(4) Property, Plant and Equipment, Net

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

	Depreciable Life	2014	2013
Utility plant in-service:			
Generation	25 - 80 years	$ 4,034	$ 3,789
Distribution	20 - 65 years	3,018	2,936
Transmission	45 - 65 years	1,757	1,743
General intangible plant	5 - 65 years	669	645
Utility plant in-service		9,478	9,113
Accumulated depreciation and amortization		(2,599)	(2,217)
Utility plant in-service, net		6,879	6,896
Other non-regulated, net of accumulated depreciation and amortization	5 - 65 years	4	3
		6,883	6,899
Construction work-in-progress		120	93
Property, plant and equipment, net		$ 7,003	$ 6,992

Almost all of the Company's plant is subject to the ratemaking jurisdiction of the PUCN and the FERC. The Company's depreciation and amortization expense, as authorized by the PUCN, stated as a percentage of the depreciable property balances as of December 31, 2014, 2013 and 2012 were 3.3%, 3.3% and 3.2%, respectively. The Company 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.

Impairment of Regulated Assets Not In Rates

The Company recorded an impairment charge of $29 million and $31 million in operating and maintenance on the Consolidated Statements of Operations for the years ended December 31, 2014 and 2013, respectively, related to the recovery of certain assets not currently in rates. Included in the 2014 impairment is $19 million related to the settlement of the 2014 general rate case.

In March 2012, the Company filed a petition with the PUCN to obtain a declaratory order and the accounting guidance necessary to establish a regulatory account for the gain on sale of the Company's telecommunication towers to Global Tower Partners, LLC. In July 2012, the PUCN approved a stipulation between the Company, the BCP, and PUCN staff that provides for an allocation of $27 million of the $32 million gain on sale to the ratepayers. The amortization of the gain will coincide with the rate effective date of January 1, 2015. The Company recorded $6 million, including an adjustment to previously recorded carrying charges, to other, net on the Consolidated Statements of Operations for the remaining balance of the gain on sale for the year ended December 31, 2012.

(5) Jointly Owned Utility Facilities

Under joint facility ownership agreements, the Company, as tenants in common, has undivided interests in jointly owned generation and transmission facilities. The Company accounts for its proportionate share of each facility and each joint owner has provided financing for its share of each 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, 2014 (dollars in millions):

	Company Share	Facility In Service	Accumulated Depreciation	Construction Work-in-Progress
Silverhawk Generating Station	75%	$ 241	$ 55	$ 5
Navajo Generating Station	11	198	135	2
ON Line Transmission Line[(1)]	24	142	3	1
Other Transmission Facilities	Various	68	27	—
Total		$ 649	$ 220	$ 8

(1) ON Line, a 500-kilovolt transmission line connecting the Company and Sierra Pacific, was placed in-service December 2013. The Company and Sierra Pacific entered into a long-term transmission use agreement, in which the Company and Sierra Pacific have 25% interest and Great Basin Transmission South, LLC has 75% interest. Refer to Note 8 for additional information.

(6) Regulatory Matters

Regulatory assets represent costs that are expected to be recovered in future 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	2014	2013
Deferred income taxes[1]	29 years	$ 156	$ 165
Merger costs from 1999 merger	29 years	149	155
Deferred excess energy costs	2 years	129	159
Decommissioning costs	8 years	113	25
Abandoned projects	5 years	107	115
Employee benefit plans[2]	10 years	85	83
Asset retirement obligations	7 years	80	98
Legacy meters	18 years	68	65
Deferred operating costs	28 years	61	63
Demand side resources	3 years	41	70
ON Line	39 years	38	—
Loss on reacquired debt	19 years	33	35
Unrealized loss on regulated derivative contracts	3 years	30	47
Other	Various	36	58
Total regulatory assets		$ 1,126	$ 1,138
Reflected as:			
Current assets		$ 57	$ 81
Other assets		1,069	1,057
Total regulatory assets		$ 1,126	$ 1,138

(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.

The Company had regulatory assets not earning a return on investment of $788 million and $598 million as of December 31, 2014 and 2013, respectively, primarily related to deferred income taxes, merger costs from 1999 merger, a portion of abandoned projects and deferred excess energy costs, asset retirement obligations, legacy meters, deferred operating costs, loss on reacquired debt and unrealized loss on regulated derivative contracts.

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	2014	2013
Cost of removal[1]	36 years	$ 295	$ 273
Energy efficiency program	1 year	25	57
Renewable energy program	1 year	15	18
Other	Various	31	38
Total regulatory liabilities		$ 366	$ 386
Reflected as:			
Current liabilities		$ 40	$ 74
Other long-term liabilities		326	312
Total regulatory liabilities		$ 366	$ 386

(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 is included in the table above as deferred excess 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 over collected. 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 Implementation Rates and Energy Efficiency Program Rates

In July 2010, regulations were adopted by the PUCN that authorizes an electric utility to recover lost revenue that is attributable to the measurable and verifiable effects associated with the implementation of efficiency and conservation programs approved by the PUCN through energy efficiency implementation rates ("EEIR"). As a result, the Company files annually in March to adjust energy efficiency program rates and EEIR for over- or under-collected balances, which are effective in October of the same year.

In March 2013, the Company filed applications with the PUCN for the twelve-month period ended December 31, 2012 to reset EEIR elements. In September 2013, the PUCN issued an order indicating that EEIR revenue should not contribute to the Company earning more than its authorized rate of return. As the Company earned in excess of its authorized rate of return in 2012, the PUCN disallowed approximately $11 million in EEIR revenue (including carrying charges) and the Company recorded a charge to operating and maintenance on the Consolidated Statements of Operations for the year ended December 31, 2013.

The PUCN's final order approving the BHE Merger stipulated that the Company will not seek recovery of any lost revenue for calendar year 2013 and, for the calendar year 2014 in an amount that exceeds 50% of the lost revenue that the Company could otherwise request. As a result, for the year ended December 31, 2013, the Company has not recorded revenue for EEIR and has recorded a regulatory liability to refund to customers amounts collected in 2013 of $12 million, which is included in current regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2013. In February 2014, the Company filed an application with the PUCN to reset the EEIR and energy efficiency program rates. In June 2014, the PUCN accepted a stipulation to adjust the EEIR, as of July 1, 2014, to collect 50% of the estimated lost revenue that the Company would otherwise be allowed to recover for the 2014 calendar year. The EEIR was effective from July through December 2014 and will reset on January 1, 2015 and remain in effect through September 2015. To the extent the Company's earned rate of return exceeds the rate of return used to set base general rates, the Company is required to refund to customers EEIR revenue collected. As a result, the Company has deferred recognition of EEIR revenue collected and has recorded a liability of $11 million, which is included in current regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2014.

General Rate Case

In May 2014, the Company filed a general rate case with the PUCN. In July 2014, the Company made its certification filing, which requested incremental annual revenue relief in the amount of $38 million, or an average price increase of 2%. In October 2014, the Company reached a settlement agreement with certain parties agreeing to a zero increase in the revenue requirement. In October 2014, the PUCN issued an order in the general rate case filing that accepted the settlement. The order provides for increases in the fixed-monthly service charge for customers with a corresponding decrease in the base tariff general rate effective January 1, 2015. As a result of the order, the Company recorded $15 million in asset impairments related to property, plant and equipment and $5 million of regulatory asset impairments, which are included in operating and maintenance on the Consolidated Statements of Operations for the year ended December 31, 2014. Additionally, the Company recorded a $5 million gain in other, net on the Consolidated Statement of Operations for the year ended December 31, 2014 related to the disposition of property. In October 2014, a party filed a petition for reconsideration of the PUCN order. In November 2014, the PUCN granted the petition for reconsideration and reaffirmed the order issued in October 2014.

2013 FERC Transmission Rate Case

In May 2013, the Company, along with Sierra Pacific, filed an application with the FERC to establish single system transmission and ancillary service rates. The combined filing requested incremental rate relief of $17 million annually to be effective January 1, 2014. In August 2013, the FERC granted the companies' request for a rate effective date of January 1, 2014 subject to refund, and set the case for hearing or settlement discussions. On January 1, 2014, the Company implemented the filed rates in this case subject to refund as set forth in the FERC's order.

In September 2014, the Company, along with Sierra Pacific, filed an unopposed settlement offer with the FERC on behalf of NV Energy and the intervening parties providing rate relief of $4 million. The settlement offer would resolve all outstanding issues related to this case. In addition, a preliminary order from the administrative law judge granting the motion for interim rate relief was issued, which authorizes the Company to institute the interim rates effective September 1, 2014, and begin billing transmission customers under the settlement rates for service provided on and after that date. In January 2015, the FERC approved the settlement and refunds will be processed in 2015. As of December 31, 2014, the Company accrued $7 million for amounts subject to rate refund, which is included in other current liabilities on the Consolidated Balance Sheets.

(7) Credit Facility

The Company 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 ("LIBOR") or a base rate, at the Company's option, plus a spread that varies based on the Company's credit ratings for its senior secured long-term debt securities. As of December 31, 2014 and 2013, the Company had no borrowings outstanding under the credit facility. Amounts due under the Company's credit facility are collateralized by the Company's general and refunding mortgage bonds. The credit facility requires the Company'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.

(8) Long-Term Debt

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

	Par Value	2014	2013
General and Refunding Mortgage Securities:			
5.875% Series L, due 2015	$ 250	$ 250	$ 250
5.950% Series M, due 2016	210	210	210
6.500% Series O, due 2018	325	323	324
6.500% Series S, due 2018	499	498	499
7.125% Series V, due 2019	500	501	501
6.650% Series N, due 2036	367	361	363
6.750% Series R, due 2037	349	348	349
5.375% Series X, due 2040	250	249	249
5.450% Series Y, due 2041	250	250	250
Variable-rate series (2014-0.455% to 0.464%, 2013-0.454% to 0.459%):			
Pollution Control Revenue Bonds Series 2006A, due 2032	38	38	38
Pollution Control Revenue Bonds Series 2006, due 2036	38	38	38
Capital and financial lease obligations - 2.750% to 11.600%, due through 2054	510	510	506
Total long-term debt	$ 3,586	$ 3,576	$ 3,577
Reflected as:			
Current portion of long-term debt		$ 264	$ 22
Long-term debt		3,312	3,555
Total long-term debt		$ 3,576	$ 3,577

The consummation of the BHE Merger also triggered mandatory redemption requirements under financing agreements of the Company. As a result, the Company offered to purchase $3.0 billion of debt at 101% of par. Debt with a par value totaling $5 million was tendered in January 2014 and paid with cash on hand. The tender offer expired in January 2014.

In November 2013, the Company issued a notice of redemption to the bondholders for its $125 million, 7.375% Series U General and Refunding Mortgage Securities. In December 2013, the Company redeemed the aggregate principal amount outstanding of $125 million at 100.7% of the principal amount plus accrued interest with the use of cash on hand.

In July 2013, the Company issued a notice of redemption to the bondholders for its $100 million Clark County Industrial Development Refunding Revenue Bonds, Series 2000A. In August 2013, the Company redeemed the aggregate principal amount outstanding of $98 million at 100% of the principal amount plus accrued interest with the use of cash on hand.

In April 2012, the Company used $120 million from its revolving credit facility along with $10 million of cash on hand to pay for the maturity of its 6.5% General and Refunding Mortgage Notes, Series I, in an aggregate principal amount of $130 million.

Annual Payment on Long-Term Debt

The annual repayments of long-term debt and capital and financial leases for the years beginning January 1, 2015 and thereafter, excluding unamortized premiums and discounts, are as follows (in millions):

	Long-term Debt	Capital and Financial Lease Obligations	Total
2015	$ 250	$ 75	$ 325
2016	210	73	283
2017	—	75	75
2018	823	74	897
2019	500	76	576
Thereafter	1,291	986	2,277
Total	3,074	1,359	4,433
Unamortized discount	(8)	—	(8)
Executory costs	—	(148)	(148)
Amounts representing interest	—	(701)	(701)
Total	$ 3,066	$ 510	$ 3,576

Utility plant of $3.5 billion is subject to the liens of the Company's indentures under which its respective General and Refunding Mortgage Securities are issued.

Capital and Financial Lease Obligations

- In 1984, the Company entered into a 30-year capital lease for the Pearson Building with five, five-year renewal options beginning in year 2015. In February 2010, the Company 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 $28 million and $39 million were included in property, plant and equipment, net as of December 31, 2014 and 2013, respectively.
- In 2007, the Company 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. The Company accounts for the building portion of the lease as a capital lease and the land portion of the lease as an operating lease. The Company transferred operations to the facilities in June 2009. Capital assets of $8 million and $10 million were included in property, plant and equipment, net as of December 31, 2014 and 2013, respectively.
- The Company has long-term energy purchase contracts which qualify as capital leases. The leases were entered into between the years 1989 and 1990 and firm operation occurred through 1993. The terms of the leases are for 30 years and expire between the years 2022-2023. Capital assets of $71 million were included in property, plant and equipment, gross as of December 31, 2014 and 2013. Capital assets of $44 million and $45 million were included in property, plant and equipment, net as of December 31, 2014 and 2013, respectively.
- The Company 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, 2014 and 2013.
- ON Line was placed in-service on December 31, 2013. The Company and Sierra Pacific entered into a long-term transmission use agreement, in which the Company and Sierra Pacific have 25% interest and Great Basin Transmission South, LLC has 75% interest. Refer to Note 5 for additional information. The Company's and Sierra Pacific's share of the long-term transmission use agreement and ownership interest is split at 95% and 5%, respectively. The term is for 41 years with the agreement ending December 31, 2054. Payments began on January 31, 2014. ON Line assets of $418 million and $419 million were included in property, plant and equipment, net as of December 31, 2014 and 2013, respectively.

(9) Risk Management and Hedging Activities

The Company is exposed to the impact of market fluctuations in commodity prices and interest rates. The Company is principally exposed to electricity, natural gas and coal market fluctuations primarily through the Company's obligation to serve retail customer load in its regulated service territory. The Company'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. The Company does not engage in proprietary trading activities.

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

There have been no significant changes in the Company's accounting policies related to derivatives. Refer to Notes 2, 9 and 10 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 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 Liabilities	Other Long-term Liabilities	Total
As of December 31, 2014			
Commodity liabilities(1)	$ (9)	$ (21)	$ (30)
As of December 31, 2013			
Commodity liabilities(1)	$ (9)	$ (38)	$ (47)

(1) The Company's commodity derivatives not designated as hedging contracts are included in regulated rates and as of December 31, 2014 and 2013, a regulatory asset of $30 million and $47 million, respectively, was recorded related to the derivative liability of $30 million and $47 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	2014	2013
Electricity sales	Megawatt hours	(3)	(4)
Natural gas purchases	Decatherms	115	118

Credit Risk

The Company 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 the Company's counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, the Company 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, the Company 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, the Company 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, 2014, 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 was $4 million, 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. The Company's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation or other factors.

(10) Fair Value Measurements

The carrying value of the Company's cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. The Company has various financial assets and liabilities that are measured at fair value on the Consolidated 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 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	Total
As of December 31, 2014				
Assets - investment funds	$ 20	$ —	$ —	$ 20
Liabilities - commodity derivatives	$ —	$ —	$ (30)	$ (30)
As of December 31, 2013				
Assets:				
Money market mutual funds(1)	$ 50	$ —	$ —	$ 50
Investment funds	22	—	—	22
	$ 72	$ —	$ —	$ 72
Liabilities - commodity derivatives	$ —	$ —	$ (47)	$ (47)

(1) Amounts are included in 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 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 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. Interest rate swaps are valued using a financial model which utilizes observable inputs for similar instruments based primarily on market price curves. The determination of the fair value for derivative contracts not only includes counterparty risk, but also the impact of the Company's nonperformance risk on its liabilities, which as of December 31, 2014, had an immaterial impact to the fair value of its derivative contracts. As such, the Company considers its derivative contracts to be valued using Level 3 inputs. Refer to Note 9 for further discussion regarding the Company's risk management and hedging activities.

The Company'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 the Company'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):

	2014
Beginning balance	$ (47)
Changes in fair value recognized in regulatory assets	9
Purchases	—
Settlements	8
Ending balance	$ (30)

The Company's long-term debt is carried at cost on the Consolidated Balance Sheets. The fair value of the Company's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of the Company's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of the Company's long-term debt as of December 31 (in millions):

	2014		2013	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 3,066	$ 3,712	$ 3,071	$ 3,596

(11) Other, Net

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

	2014	2013	2012
Interest and dividend income	$ 2	$ 5	$ 4
Donations	—	—	(2)
Interest expense on regulatory items	6	(2)	(7)
Other	14	2	2
Total other, net	$ 22	$ 5	$ (3)

(12) Income Taxes

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

	2014	2013	2012
Current – Federal	$ —	$ (1)	$ (12)
Deferred – Federal	131	96	151
Investment tax credits	(1)	(1)	(1)
Total income tax expense	$ 130	$ 94	$ 138

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:

	2014	2013	2012
Federal statutory income tax rate	35%	35%	35%
Non-deductible BHE Merger related expenses	—	3	—
Effects of ratemaking	1	1	1
Other	—	—	(1)
Effective income tax rate	36%	39%	35%

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

	2014	2013
Deferred income tax assets:		
Federal net operating loss and credit carryforwards	$ 158	$ 265
Capital and financial leases	178	177
Employee benefits	22	11
Regulatory liabilities	37	4
Other	57	85
Total deferred income tax assets	452	542
Valuation allowance	(2)	(2)
Total deferred income tax assets, net	450	540
Deferred income tax liabilities:		
Property related items	(1,175)	(1,145)
Regulatory assets	(341)	(314)
Capital and financial leases	(174)	(189)
Other	(29)	(38)
Total deferred income tax liabilities	(1,719)	(1,686)
Net deferred income tax liability	$ (1,269)	$ (1,146)
Reflected as:		
Deferred income taxes - current asset	$ 145	$ 152
Deferred income taxes - long-term liability	(1,414)	(1,298)
Net deferred income tax liability	$ (1,269)	$ (1,146)

The following table provides the Company's federal net operating loss and tax credit carryforwards and expiration dates as of December 31, 2014 (in millions):

Net operating loss carryforwards	$ 420
Deferred income taxes on federal net operating loss carryforwards	$ 147
Expiration dates	2030-2034
Other tax credits	$ 11
Expiration dates	2015-2033

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.

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):

	2014	2013
Beginning balance	$ 3	$ 4
Additions for tax positions of prior years	—	—
Reductions for tax positions of prior years	—	(1)
Ending balance	$ 3	$ 3

As of December 31, 2014 and 2013, the Company had unrecognized tax benefits totaling $2 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 the Company's effective income tax rate.

(13) Related Party Transactions

Kern River Gas Transmission Company, an indirect subsidiary of BHE, provided natural gas transportation and other services to the Company of $68 million, $68 million and $66 million for the years ended December 31, 2014, 2013 and 2012, respectively. As of December 31, 2014 and 2013, the Company's Consolidated Balance Sheets included amounts due to Kern River Gas Transmission Company of $5 million.

The Company's accounts receivable, net as of December 31, 2013 included $2 million for amounts due from BHE for merger related reimbursements, which were received in 2014.

The Company provided electricity and other services to PacifiCorp, an indirect subsidiary of BHE, of $3 million, $3 million and $7 million for the years ended December 31, 2014, 2013 and 2012, respectively. There were no receivables associated with these services as of December 31, 2014 and 2013. PacifiCorp provided electricity and the sale of renewable energy credits to the Company of $5 million, $2 million and $62 million for the years ended December 31, 2014, 2013 and 2012, respectively. Payables associated with these transactions were $4 million and $- million as of December 31, 2014 and 2013, respectively.

The Company provided electricity to Sierra Pacific of $33 million, $36 million and $20 million for the years ended December 31, 2014, 2013 and 2012, respectively. Receivables associated with these transactions were $7 million and $3 million as of December 31, 2014 and 2013, respectively. The Company purchased electricity from Sierra Pacific of $8 million, $1 million and $1 million for the years ended December 31, 2014, 2013 and 2012, respectively. There were no associated payables as of December 31, 2014 and 2013.

The Company incurs intercompany administrative and shared facility costs between NV Energy and Sierra Pacific. These transactions are governed by an intercompany service agreement and are priced at cost. The Company provided services to NV Energy of $1 million, $- million, and $1 million for the years ending December 31, 2014, 2013 and 2012, respectively. NV Energy provided services to the Company of $19 million, $45 million and $27 million for the years ending December 31, 2014, 2013 and 2012, respectively. The Company provided services to Sierra Pacific of $20 million, $24 million and $20 million for the years ended December 31, 2014, 2013 and 2012, respectively. Sierra Pacific provided services to the Company of $16 million, $22 million and $22 million for the years ended December 31, 2014, 2013 and 2012, respectively. As of December 31, 2014 and 2013, the Company's Consolidated Balance Sheets included amounts due to NV Energy of $33 million and $60 million, respectively. As of December 31, 2014 and 2013, the Company's Consolidated Balance Sheets included receivables due from Sierra Pacific of $5 million and $6 million, respectively.

Certain disbursements for accounts payable and payroll are made by NV Energy on behalf of the Company and reimbursed automatically when settled by the bank. These amounts are recorded as accounts payable at the time of disbursement.

(14) Retirement Plan and Postretirement Benefits

The Company 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 the Company. The Company did not make any contributions to the Qualified Pension Plan, Non-Qualified Pension Plans or Other Postretirement Plans for the years ended December 31, 2014, 2013 and 2012. Amounts attributable to the Company 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 income (loss).

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):

	2014	2013
Qualified Pension Plan:		
Other assets	$ —	$ 13
Other long-term liabilities	(23)	—
Non-Qualified Pension Plans:		
Other current liabilities	(1)	(4)
Other long-term liabilities	(9)	(8)
Other Postretirement Plans -		
Other long-term liabilities	1	(7)

(15) 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 $295 million and $273 million as of December 31, 2014 and 2013, respectively.

The following table presents the Company's ARO liabilities by asset type as of December 31 (in millions):

	2014	2013
Evaporative ponds and dry ash landfills	$ 25	$ 48
Waste water remediation	53	36
Asbestos	3	4
Other	5	12
Total asset retirement obligations	$ 86	$ 100

The following table reconciles the beginning and ending balances of the Company's ARO liabilities for the years ended December 31 (in millions):

	2014	2013
Beginning balance	$ 100	$ 60
Change in estimated costs	(18)	37
Accretion	4	3
Ending balance	$ 86	$ 100
Reflected as:		
Other current liabilities	$ 14	$ —
Other long-term liabilities	72	100
	$ 86	$ 100

In 2008, the Company 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, the Company 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 the Company and California Department of Water Resources ("CDWR") for the Reid Gardner Generating Station Unit No. 4, the Company 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. The 2014 and 2013 change in estimated costs was primarily related to refinement of expected remediation costs at the Reid Gardner Generating Station.

Certain of the Company's decommissioning and reclamation obligations relate to jointly-owned facilities, and as such, the Company 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 in other long-term liabilities on the Consolidated Balance Sheets.

In December 2014, the 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 will be effective 180 days after it is published in the Federal Register. 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. The Company is currently evaluating the requirements and costs of the new rule and cannot determine the impact on its ARO liabilities at this time.

(16) Commitments and Contingencies

Environmental Laws and Regulations

The Company 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 the Company's current and future operations. The Company believes it is in material compliance with all applicable laws and regulations.

In June 2013, the Nevada State Legislature passed Senate Bill No. 123, which included, in significant part:

- Accelerating the plan to retire 800 MWs of coal plants, starting as soon as December 31, 2014;
- Replacement of such coal plants by issuing requests for proposals for the procurement of 300 MWs from renewable facilities;
- Construction or acquisition and ownership of 50 MWs of electric generating capacity from renewable facilities;
- Construction or acquisition and ownership of 550 MWs of additional electric generating capacity; and
- Assuring regulatory procedures that protect reliability and supply and address financial impacts on customer and utility.

In May 2014, the Company filed its Emissions Reduction Capacity Replacement Plan ("ERCR Plan") in compliance with Senate Bill No. 123 ("SB 123") enacted by the 2013 Nevada Legislature. The filing proposed, among other items, the retirement of Reid Gardner Generating Station units 1, 2 and 3 in 2014 and unit 4 in 2017; the elimination of the Company's ownership interest in Navajo Generating Station in 2019; and a plan to replace the generating capacity being retired, as required by SB 123. The ERCR Plan includes the issuance of requests for proposals for 300 MW of renewable energy to be issued between 2014 and 2016; the acquisition of a 272-MW natural gas co-generating facility in 2014; the acquisition of a 210-MW natural gas peaking facility in 2014; the construction of a 15-MW solar photovoltaic facility expected to be placed in-service in 2015; and the construction of a 200-MW solar photovoltaic facility expected to be placed in-service in 2016. In the second quarter of 2014, the Company executed various contractual agreements to fulfill the proposed ERCR Plan, which are subject to the PUCN approval. The PUCN issued an order dated October 28, 2014 removing the 200-MW solar photovoltaic facility proposed by the Company from the ERCR Plan but accepting the remaining requests. In November 2014, the Company filed a petition for reconsideration, but in December 2014, the PUCN upheld the original order from October 2014 with respect to material matters. In December 2014, the Company filed its acceptance of the modifications to the ERCR Plan.

Reid Gardner Generation Station

In October 2011, the Company received a request for information from the Environmental Protection Agency Region 9 under Section 114 of the Clean Air Act requesting current and historical operations and capital project information for the Company's Reid Gardner Generating Station located near Moapa, Nevada. The Environmental Protection Agency'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 Environmental Protection Agency relating to the plant. The Company completed its responses to the Environmental Protection Agency during the first quarter of 2012 and will continue to monitor developments relating to this Section 114 request. At this time, the Company cannot predict the impact, if any, associated with this information request.

Legal Matters

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

November 2005 Land Investors

In 2006, November 2005 Land Investors, LLC ("NLI") purchased from the United States through the Bureau of Land Management 2,675 acres of land located in North Las Vegas, Nevada. A small portion of the land is traversed by a 500 kilovolt ("kV") transmission line owned by the Company and sited pursuant to a pre-existing right-of-way grant from the Bureau of Land Management. Subsequent to NLI's purchase, a dispute arose as to whether the Company owed rent and, if it did, the amount owed to NLI under the right-of-way grant. NLI eventually "terminated" the right-of-way grant and brought claims against the Company for breach of contract, inverse condemnation and trespass. The Company counterclaimed for express condemnation of a perpetual easement over the right-of-way corridor. The matter proceeded to trial in the Eighth District Court, Clark County, Nevada ("Eighth District Court"). In September 2013, the Eighth District Court awarded NLI $1 million for unpaid rent and $5 million for inverse condemnation, plus interest and attorneys' fees, bringing the total judgment to $12 million. The Eighth District Court also found the Company was entitled to judgment in its favor on its counterclaim for condemnation of the right-of-way corridor. The Company has posted the required bond of $12 million and has appealed to the Nevada Supreme Court. The Company cannot assess or predict the outcome of the case at this time.

Park Highlands

The Company has six other rights-of-way located on the same 2,675 acres of land located in North Las Vegas, Nevada, commonly referred to as the Park Highlands properties. NLI purportedly also terminated the other six rights-of-way. On January 2, 2015 KBS SOR Park Highlands, LLC (“KBS”) filed a complaint in the Eighth District Court relating to one of the six rights-of-way, specifically the right-of-way that relates to a 230-kV line that traverses the property. In the complaint, KBS raised the same claims previously raised by NLI in the litigation relating to the 500-kV line. The Company plans to vigorously defend the matter. The Company cannot assess or predict the outcome of the case at this time.

On January 9, 2015, the Company filed an action in the Eighth District Court relating to the six rights-of-way on the Park Highlands properties. This action seeks a declaratory order quieting the Company's title to the rights-of-way or in the alternative condemning an easement interest in the property. The Company plans to vigorously prosecute this matter to perfect its property rights. The Company cannot assess or predict the outcome of the case at this time.

Skye Canyon

In 2005, the Bureau of Land Management sold at auction a parcel of land commonly known as the Skye Canyon properties. The property was sold subject to preexisting rights-of-way held by the Company for the placement of electric transmission and distribution facilities. On January 9, 2015, the Company filed an action in the Eighth District Court relating to 14 rights-of-way located within the Skye Canyon properties. The action seeks a declaratory order from the court that the rights-of-way held by the Company are still valid, seeks to establish the proper rent, if any, payable by the Company and to identify the proper party to whom rent is due. In the alternative, the Company is condemning an easement interest for the 14 rights-of-way. The Company plans to vigorously prosecute this case. The Company cannot assess or predict the outcome of the case at this time.

Sierra Club and Moapa Band of Paiute Indians

In August 2013, the Sierra Club and Moapa Band of Paiute Indians filed a complaint in federal district court in Nevada against the Company and CDWR, alleging that activities at the Reid Gardner Generating Station are causing imminent and substantial harm to the environment and that placement of coal combustion residuals at the on-site landfill constitute "open dumping" in violation of the Resource Conservation and Recovery Act. The complaint also alleges that the Reid Gardner Generating Station is engaged in the unlawful discharge of pollutants in violation of the Clean Water Act. The notice was issued pursuant to the citizen suit provisions of the Resource Conservation and Recovery Act and the Clean Water Act. CDWR was named as a co-defendant in the litigation due to its prior co-ownership in Reid Gardner Generating Station Unit 4. The complaint seeks various injunctive remedies, assessment of civil penalties, and reimbursement of plaintiffs' attorney and legal fees and costs. In August 2014, the court dismissed without prejudice the plaintiff's amended complaint which sought civil penalties. The Company answered the complaint and has recently engaged in discussions with the plaintiffs to determine if a settlement can be reached that avoids the costs and burden of litigation. The Company cannot assess or predict the outcome of the case at this time.

Commitments

The Company has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2014 are as follows (in millions):

	2015	2016	2017	2018	2019	2020 and Thereafter	Total
Contract type:							
Fuel and capacity contract commitments	$ 607	$ 447	$ 363	$ 289	$ 290	$ 3,058	$ 5,054
Fuel and capacity contract commitments (not commercially operable)	65	79	80	81	88	1,883	2,276
Construction commitments	42	—	—	—	—	—	42
Operating leases and easements	9	7	6	7	7	52	88
Maintenance, service and other contracts	39	38	38	36	38	161	350
Total commitments	$ 762	$ 571	$ 487	$ 413	$ 423	$ 5,154	$ 7,810

Fuel and Capacity Contract Commitments

Purchased Power

The Company has several contracts for long-term purchase of electric energy which have been approved by the PUCN. The expiration of these contracts range from 2015 to 2039. Purchased power includes contracts which meet the definition of a lease. The Company's rent expense for purchase power contracts which met the lease criteria for 2014, 2013 and 2012 were $245 million, $400 million and $353 million, respectively, and are recorded as cost of fuel, energy and capacity on the Consolidated Statements of Operations.

Coal and Natural Gas

The Company has a long-term contract for the purchase of coal that extends through 2019 and a contract for the transportation of coal that extends through 2017. Additionally, gas transportation contracts expire from 2015 to 2031 and the gas supply contract expires in 2016.

Fuel and Capacity Contract Commitments - Not Commercially Operable

The Company 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.

Construction Commitments

The Company's construction commitments included in the table above relate to firm commitments to build a solar facility on the Nellis Air Force Base.

Operating Leases

The Company has non-cancelable operating leases primarily for office equipment, office space, certain operating facilities, vehicles and land. 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. Rent expense on non-cancelable operating leases totaled $10 million, $9 million and $10 million for the year-ended December 31, 2014, 2013 and 2012, respectively.

Maintenance, Service and Other Contracts

The Company 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 2024 to 2028.

(17) 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):

	2014	2013	2012
Supplemental disclosure of cash flow information -			
Interest paid, net of amounts capitalized	$ 194	$ 209	$ 208
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 30	$ 25	$ 150
Capital and financial lease obligations incurred	$ 7	$ 419	$ —

(18) Unaudited Quarterly Operating Results (in millions)

	Three-Month Periods Ended			
	March 31, 2014	June 30, 2014	September 30, 2014	December 31, 2014
Operating revenues	$ 417	$ 595	$ 867	$ 458
Operating income	55	145	307	34
Net income	6	62	168	(9)

	Three-Month Periods Ended			
	March 31, 2013	June 30, 2013	September 30, 2013	December 31, 2013
Operating revenues	$ 372	$ 537	$ 786	$ 397
Operating income	58	141	305	(69)
Net income	5	59	164	(83)

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, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the President and Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) promulgated under the Securities and Exchange Act of 1934, as amended). Based upon that evaluation, the Company's management, including the President and Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), concluded that the Company's disclosure controls and procedures were effective to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and is accumulated and communicated to management, including the Company's President and Chief Executive Officer (principal executive officer) and Chief Financial Officer (principal financial officer), or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. There has been no change in the Company's internal control over financial reporting during the quarter ended December 31, 2014 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in the Securities Exchange Act of 1934 Rule 13a-15(f). Under the supervision and with the participation of the Company's management, including the President and Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), the Company's management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting as of December 31, 2014 as required by the Securities Exchange Act of 1934 Rule 13a-15(c). In making this assessment, the Company's management used the criteria set forth in the framework in "Internal Control - Integrated Framework (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)", the Company's management concluded that the Company's internal control over financial reporting was effective as of December 31, 2014.

Nevada Power Company
February 27, 2015

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information required by Item 10 is omitted pursuant to General Instruction I(2)(c) for Form 10-K.

Item 11. Executive Compensation

Information required by Item 11 is omitted pursuant to General Instruction I(2)(c) for Form 10-K.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by Item 12 is omitted pursuant to General Instruction I(2)(c) for Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by Item 13 is omitted pursuant to General Instruction I(2)(c) for Form 10-K.

Item 14. Principal Accountant Fees and Services

The following table shows the Company's fees paid or accrued for audit and audit-related services and fees paid for tax and all other services rendered by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu Limited, and their respective affiliates (collectively, the "Deloitte Entities") for each of the last two years (in millions):

	2014	2013
Audit fees(1)	$ 0.9	$ 1.0
Audit-related fees(2)	—	—
Tax fees(3)	—	—
Total	$ 0.9	$ 1.0

(1) Audit fees include fees for the audit of the Company's consolidated financial statements and interim reviews of the Company's quarterly financial statements, audit services provided in connection with required statutory audits, comfort letters, consents and other services related to SEC matters.

(2) Audit-related fees primarily include fees for assurance and related services for any other statutory or regulatory requirements, audits of 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 and state tax compliance, tax return preparation and tax audits.

The audit committee of BHE has considered whether the non-audit services provided to the Company 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 a manner consistent with the pre-approval policy adopted by the audit committee of BHE. 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 Company. The policy (a) identifies the guiding principles that must be considered by the audit committee of BHE 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 of BHE will be submitted to the audit committee of BHE by both the Company's 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 of BHE 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 of BHE. The audit committee of BHE 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 Schedule

(i) Financial Statements:

Consolidated Financial Statements are included in Item 8 41

(ii) Financial Statement Schedules:

All schedules have been omitted because they are either not applicable, not required or the information required to be set forth therein is included on the Consolidated Financial Statements or notes thereto.

(b) Exhibits

The exhibits listed on the accompanying Exhibit Index are filed as part of this Annual Report. 75

(c) Financial statements required by Regulation S-X, which are excluded from the Annual Report by Rule 14a-3 (b).

Not applicable.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on this 27th day of February, 2015.

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 27, 2015
/s/ E. Kevin Bethel E. Kevin Bethel	Senior Vice President, Chief Financial Officer and Director (principal financial and accounting officer)	February 27, 2015
/s/ Douglas A. Cannon Douglas A. Cannon	Senior Vice President, Corporate Secretary, General Counsel and Director	February 27, 2015
/s/ Patrick S. Egan Patrick S. Egan	Senior Vice President, Customer Services and Director	February 27, 2015
/s/ Kevin C. Geraghty Kevin C. Geraghty	Director	February 27, 2015
/s/ Francis P. Gonzales Francis P. Gonzales	Director	February 27, 2015
/s/ John C. Owens John C. Owens	Director	February 27, 2015
/s/ Tony F. Sanchez, III Tony F. Sanchez, III	Senior Vice President, Government and Community Strategy and Director	February 27, 2015

EXHIBIT INDEX

Exhibits Filed Herewith

Exhibit No.	Description
12.1	Computation of Ratios of Earnings to Fixed Charges.
23.1	Consent of Deloitte & Touche LLP.
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.
101	The following financial information from Nevada Power Company's Annual Report on Form 10-K for the year ended December 31, 2014 is formatted in XBRL (eXtensible Business Reporting Language) and included herein: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Changes in Shareholder's Equity, (iv) the Consolidated Statements of Cash Flows and (v) the Notes to Consolidated Financial Statements, tagged in summary and detail.

Exhibits Incorporated by Reference

Exhibit No.	Description
3.1	Restated Articles of Incorporation of Nevada Power Company, dated July 28, 1999 (filed as Exhibit 3(B) to Form 10-K for year ended December 31, 1999).
3.2	Amended and Restated By-Laws of Nevada Power Company dated July 28, 1999 (filed as Exhibit 3(C) to Form 10-K for year ended December 31, 1999).
4.1	General and Refunding Mortgage Indenture, dated May 1, 2001, between Nevada Power Company and The Bank of New York, as Trustee (filed as Exhibit 4.1(a) to Form 10-Q for the quarter ended June 30, 2001).
4.2	Agreement of Resignation, Appointment and Acceptance dated November 6, 2009 by and among Nevada Power Company d/b/a NV Energy, The Bank of New York Mellon and The Bank of New York Trust Company, N.A. (filed as Exhibit 4.2 to Form 10-K for the year ended December 31, 2009).
4.3	Officer's Certificate establishing the terms of Nevada Power Company's 5 7/8% General and Refunding Mortgage Notes, Series L, due 2015 (filed as Exhibit 4(A) to Form 10-K filed for year ended December 31, 2005).
4.4	Officer's Certificate establishing the terms of Nevada Power Company's 5.95% General and Refunding Mortgage Notes, Series M, due 2016 (filed as Exhibit 4(A) to Form 10-K for the year ended December 31, 2005).
4.5	Form of Nevada Power Company's 5.95% General and Refunding Mortgage Notes, Series M, due 2016 (filed as Exhibit 4(B) to Form 10-K for the year ended December 31, 2005).
4.6	Officer's Certificate establishing the terms of Nevada Power Company's 6.650% General and Refunding Mortgage Notes, Series N, due 2036 (filed as Exhibit 4.1 to Form 10-Q for the quarter ended March 31, 2006).
4.7	Form of Nevada Power Company's 6.650% General and Refunding Mortgage Notes, Series N, due 2036 (filed as Appendix A to Exhibit 4.1 to Form 10-Q for the quarter ended March 31, 2006).
4.8	Officer's Certificate establishing the terms of Nevada Power Company's 6.50% General and Refunding Mortgage Notes, Series O, due 2018 (filed as Exhibit 4.7 to Form S-4 filed June 7, 2006).
4.9	Form of Nevada Power Company's 6.50% General and Refunding Mortgage Notes, Series O, due 2018 (filed as Appendix A to Exhibit 4.7 to Form S-4 filed June 7, 2006).

Exhibit No.	Description
4.10	Officer's Certificate establishing the terms of Nevada Power Company's 6.750% General and Refunding Mortgage Notes, Series R, due 2037 (filed as Exhibit 4.1 to Form 8-K dated June 27, 2007).
4.11	Form of Nevada Power Company's 6.750% General and Refunding Mortgage Notes, Series R, due 2037 (filed as Appendix A to Exhibit 4.1 to Form 8-K dated June 27, 2007).
4.12	Officer's Certificate establishing the terms of Nevada Power Company's 6.50% General and Refunding Mortgage Notes, Series S, due 2018 (filed as Exhibit 4.1 to Form 8-K dated July 28, 2008).
4.13	Form of Nevada Power Company's 6.50% General and Refunding Mortgage Notes, Series S, due 2018 (filed as Appendix A to Exhibit 4.1 to Form 8-K dated July 28, 2008).
4.14	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 (filed as Exhibit 4.1 to Form 8-K dated February 25, 2009).
4.15	Form of Nevada Power Company d/b/a NV Energy's 7.125% General and Refunding Mortgage Notes, Series V, due 2019 (filed as Appendix A to Exhibit 4.1 to Form 8-K dated February 25, 2009).
4.16	Officers' 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 (filed as Exhibit 4.1 to Form 8-K dated September 10, 2010).
4.17	Form of Nevada Power Company d/b/a NV Energy's 5.375% General and Refunding Mortgage Notes, Series X, due 2040 (filed as Appendix A to Exhibit 4.1 to Form 8-K dated September 10, 2010).
4.18	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 (filed as Exhibit 4.1 to Form 8-K dated May 9, 2011).
4.19	Form of Nevada Power Company d/b/a NV Energy's General and Refunding Mortgage Notes, Series Y, due 2041 (filed as Appendix A to Exhibit 4.1 to Form 8-K dated May 9, 2011).
10.1	Transmission Use and Capacity Exchange Agreement between Nevada Power Company, Sierra Pacific Power Company and Great Basin Transmission, LLC dated August 20, 2010 (filed as Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2010).
10.2	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) (filed as Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2006).
10.3	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) (filed as Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2006).
10.4	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) (filed as Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2006).
10.5	Credit Agreement dated March 23, 2012 between Nevada Power Company d/b/a NV Energy and Wells Fargo Bank, N.A., as administrative agent for the lenders (filed as Exhibit 10.1 to Form 10-Q for the quarter ended March 30, 2012).
10.6	$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).
14.1	Code of Ethics for Chief Executive Officer, Chief Financial Officer and Other Covered Officers.

EXHIBIT 12.1

NEVADA POWER COMPANY
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars in millions)

	Years Ended December 31,				
	2014	**2013**	**2012**	**2011**	**2010**
Earnings available for fixed charges:					
Net income	$ 227	$ 145	$ 258	$ 133	$ 186
Add (deduct):					
Income tax expense	130	94	138	71	92
Fixed charges	211	220	220	234	241
Capitalized interest (allowance for borrowed funds used during construction)	(1)	(6)	(5)	(7)	(21)
	340	308	353	298	312
Total earnings available for fixed charges	$ 567	$ 453	$ 611	$ 431	$ 498
Fixed charges -					
Interest expense(1)	211	220	220	234	241
Total fixed charges	$ 211	$ 220	$ 220	$ 234	$ 241
Ratio of earnings to fixed charges	2.7x	2.1x	2.8x	1.8x	2.1x

(1) Includes amortization of premiums, discounts, and capitalized debt expense and interest component of rent expense.

For the purpose of calculating the ratios of earnings to fixed charges, "Earnings" represents net income adjusted for income taxes plus fixed charges (excluding capitalized interest). "Fixed Charges" represent the aggregate of interest charges on long-term debt (whether expensed or capitalized) and the portion or rental expense deemed attributable to interest.

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-190869-02 on Form S-3 of our report dated February 27, 2015 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, 2014.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 27, 2015

EXHIBIT 31.1

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.

February 27, 2015

/s/ Paul J. Caudill
Paul J. Caudill
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.2

**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.

February 27, 2015

/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, 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 the Company for the annual period ended December 31, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o (d)); and

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

February 27, 2015

/s/ Paul J. Caudill
Paul J. Caudill
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.2

**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 the Company for the annual period ended December 31, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o (d)); and

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

February 27, 2015

/s/ E. Kevin Bethel
E. Kevin Bethel
Senior Vice President, Chief Financial Officer and Director
(principal financial officer)