BLACK HILLS CORP /SD/
Form 10-K
February 25, 2015

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 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

o 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 001-31303

BLACK HILLS CORPORATION

Incorporated in South Dakota	625 Ninth Street Rapid City, South Dakota 57701	IRS Identification Number 46-0458824

Registrant's telephone number, including area code
(605) 721-1700

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common stock of $1.00 par value	New York Stock Exchange

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

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 o No x

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

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

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 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. x

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company (as defined in Rule 12b-2 of the Exchange Act).

Large accelerated filer x Accelerated filer o Non-accelerated filer o Smaller reporting company o

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No x

State the aggregate market value of the voting stock held by non-affiliates of the Registrant.

At June 30, 2014	$2,696,775,649

Indicate the number of shares outstanding of each of the Registrant’s classes of common stock, as of the latest practicable date.

Class	Outstanding at January 31, 2015
Common stock, $1.00 par value	44,676,072 shares

Documents Incorporated by Reference

Portions of the Registrant’s Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2015 Annual Meeting of Stockholders to be held on April 28, 2015, are incorporated by reference in Part III of this Form 10-K.

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GLOSSARY OF TERMS AND ABBREVIATIONS

The following terms and abbreviations appear in the text of this report and have the definitions described below:

AC	Alternating current
AFUDC	Allowance for Funds Used During Construction
AltaGas	AltaGas Renewable Energy Colorado LLC, a subsidiary of AltaGas Ltd.
AOCI	Accumulated Other Comprehensive Income
Aquila Transaction	Our July 14, 2008 acquisition of five utilities from Aquila, Inc.
ARO	Asset Retirement Obligations
ASC	Accounting Standards Codification
ASU	Accounting Standards Update as issued by the FASB
Baseload plant	A power generation facility used to meet some or all of a given region’s continuous energy demand, producing energy at a constant rate.
Basin Electric	Basin Electric Power Cooperative
Bbl	Barrel
Bcfe	Billion cubic feet equivalent
BHC	Black Hills Corporation; the Company
BHEP	Black Hills Exploration and Production, Inc., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings, includes Black Hills Gas Resources, Inc. and Black Hills Plateau Production LLC, direct wholly-owned subsidiaries of Black Hills Exploration and Production, Inc.
BHSC	Black Hills Service Company LLC, a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Colorado IPP	Black Hills Colorado IPP, LLC a direct wholly-owned subsidiary of Black Hills Electric Generation
Black Hills Energy	The name used to conduct the business of Black Hills Utility Holdings, Inc., and its subsidiaries
Black Hills Electric Generation	Black Hills Electric Generation, LLC, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
BLM	United States Bureau of Land Management
Btu	British thermal unit
CFTC	United States Commodity Futures Trading Commission
CG&A	Cawley, Gillespie & Associates, Inc., an independent consulting and engineering firm
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation
Cheyenne Light Pension Plan	The Cheyenne Light, Fuel and Power Company Pension Plan
Cheyenne Prairie	Cheyenne Prairie Generating Station is a 132 MW natural-gas fired generating facility jointly owned by Black Hills Power and Cheyenne Light in Cheyenne, Wyoming. Cheyenne Prairie was placed into commercial service on October 1, 2014.
City of Gillette	The City of Gillette, Wyoming, affiliate of the JPB. The JPB financed the purchase of 23% of Wygen III power plant for the City of Gillette.

CO_2	Carbon dioxide

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Colorado Electric	Black Hills Colorado Electric Utility Company, LP (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings
Colorado Gas	Black Hills Colorado Gas Utility Company, LP (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings
Cooling Degree Day	A cooling degree day is equivalent to each degree that the average of the high and low temperature for a day is above 65 degrees. The warmer the climate, the greater the number of cooling degree days. Cooling degree days are used in the utility industry to measure the relative warmth of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30 year average.
CPCN	Certificate of Public Convenience and Necessity
CPUC	Colorado Public Utilities Commission
CT	Combustion turbine
CVA	Credit Valuation Adjustment
DART	Days Away Restricted Transferred (number of cases with days away from work or job transfer or restrictions multiplied by 200,000 then divided by total hours worked for all employees during the year covered)
DC	Direct current
De-designated interest rate swaps	The $250 million notional amount interest rate swaps that were originally designated as cash flow hedges under the accounting for derivatives and hedges but subsequently de-designated in December 2008. These swaps were settled in November 2013.
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DSM	Demand Side Management
DRSPP	Dividend Reinvestment and Stock Purchase Plan
Dth	Dekatherms
EBITDA	Earnings before interest, taxes, depreciation and amortization, a non-GAAP measurement
ECA	Energy Cost Adjustment -- adjustments that allow us to pass the prudently-incurred cost of fuel and purchased energy through to customers.
Economy Energy	Electricity purchased by one utility from another utility to take the place of electricity that would have cost more to produce on the utility’s own system
Enserco	Enserco Energy Inc., a formerly wholly-owned subsidiary of Black Hills Non-regulated Holdings, which is presented in discontinued operations throughout this Annual Report filed on Form 10-K
EPA	United States Environmental Protection Agency
EPA Region VIII	EPA Region VIII (Mountains and Plains) located in Denver serving Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming and 27 Tribal Nations
EWG	Exempt Wholesale Generator
FASB	Financial Accounting Standards Board
FDIC	Federal Depository Insurance Corporation
FERC	United States Federal Energy Regulatory Commission
Fitch	Fitch Ratings
GAAP	Accounting principles generally accepted in the United States of America
GADS	Generation Availability Data System
GCA	Gas Cost Adjustment -- adjustments that allow us to pass the prudently-incurred cost of gas and certain services through to customers.
GHG	Greenhouse gases
Global Settlement	Settlement with a utilities commission where the dollar figure is agreed upon, but the specific adjustments used by each party to arrive at the figure are not specified in public

	rate orders
Happy Jack	Happy Jack Wind Farm, LLC, owned by Duke Energy Generation Services

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Heating Degree Day	A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the utility industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30 year average.
IEEE	Institute of Electrical and Electronics Engineers
IFRS	International Financial Reporting Standards
Iowa Gas	Black Hills Iowa Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
IPP	Independent power producer
IPP Transaction	The July 11, 2008 sale of seven of our IPP plants
IRS	United States Internal Revenue Service
IUB	Iowa Utilities Board
JPB	Consolidated Wyoming Municipalities Electric Power System Joint Powers Board. The JPB exists for the purpose of, among other things, financing the electrical system of the City of Gillette.
KCC	Kansas Corporation Commission
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
kV	Kilovolt
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Loveland Area Project	Part of the Western Area Power Association transmission system
MACT	Maximum Achievable Control Technology
MAPP	Mid-Continent Area Power Pool
MATS	Utility Mercury and Air Toxics Rules under the United States EPA National Emissions Standards for Hazardous Air Pollutants from Coal and Oil Fired Electric Utility Steam Generating Units
Mbbl	Thousand barrels of oil
Mcf	Thousand cubic feet
Mcfe	Thousand cubic feet equivalent
MDU	Montana Dakota Utilities Co., a regulated utility division of MDU Resources Group, Inc.
MEAN	Municipal Energy Agency of Nebraska
MGP	Manufactured Gas Plants
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMcfe	Million cubic feet equivalent
Moody's	Moody's Investors Service, Inc.
MSHA	Mine Safety and Health Administration
MTPSC	Montana Public Service Commission
MW	Megawatts
MWh	Megawatt-hours
N/A	Not Applicable
Native load	Energy required to serve customers within our service territory
Nebraska Gas	Black Hills Nebraska Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
NERC	North American Electric Reliability Corporation

NGL	Natural Gas Liquids (1 barrel equals 6 Mcfe)
NOAA	National Oceanic and Atmospheric Administration

NOAA Climate Normals	This dataset is produced once every 10 years. This dataset contains daily and monthly normals of temperature, precipitation, snowfall, heating and cooling degree days, frost/freeze dates, and growing degree days calculated from observations at approximately 9,800 stations operated by NOAA's National Weather Service.
NO_x	Nitrogen oxide
NOL	Net operating loss
NOPA	Notice of Proposed Adjustment
NPDES	National Pollutant Discharge Elimination System
NPSC	Nebraska Public Service Commission
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
OSHA	Occupational Safety & Health Administration
OTC	Over-the-counter
PCA	Power Cost Adjustment
PCCA	Power Capacity Cost Adjustment
PPA	Power Purchase Agreement
PPACA	Patient Protection and Affordable Care Act of 2010
PSCo	Public Service Company of Colorado
PUD	Proved undeveloped reserves
PUHCA 2005	Public Utility Holding Company Act of 2005
Quad O Regulation	40 CFR 60 Subpart OOOO - Standards of performance for crude oil and natural gas production, transmission and distribution
RCRA	Resource Conservation and Recovery Act
RICE	Reciprocating Internal Combustion Engines
REPA	Renewable Energy Purchase Agreement
Revolving Credit Facility	Our $500 million credit facility used to fund working capital needs, letters of credit and other corporate purposes, which matures in 2019
RMSA	Retirement Medical Savings Account
SAIDI	System Average Interruption Duration Index
SDPUC	South Dakota Public Utilities Commission
SEC	U. S. Securities and Exchange Commission
Silver Sage	Silver Sage Windpower, LLC, owned by Duke Energy Generation Services
SO_2	Sulfur dioxide
S&P	Standard & Poor's, a division of The McGraw-Hill Companies, Inc.
S&S	Significant and substantial
Spinning Reserve	Generation capacity that is on-line but unloaded and that can respond within 10 minutes to compensate for generation or transmission outages.
System Peak Demand	Represents the highest point of customer usage for a single hour for the system in total. Our system peaks include demand loads for 100% of plants regardless of joint ownership.
TCA	Transmission Cost Adjustment -- adjustments passed through to the customer based on transmission costs that are higher or lower than the costs approved in the rate case.
TCIR	Total Case Incident Rate (average number of work-related injuries incurred by 100 workers during a one-year period)
TIPA	Tax Increase Prevention Act of 2014
VEBA	Voluntary Employee Benefit Association
VOC	Volatile Organic Compound
WDEQ	Wyoming Department of Environmental Quality
WECC	Western Electricity Coordinating Council

WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
WTI	West Texas Intermediate Crude

Website Access to Reports

The reports we file with the SEC are available free of charge at our website www.blackhillscorp.com as soon as reasonably practicable after they are filed. In addition, the charters of our Audit, Governance and Compensation Committees are located on our website along with our Code of Business Conduct, Code of Ethics for our Chief Executive Officer and Senior Finance Officers, Corporate Governance Guidelines of the Board of Directors and Policy for Director Independence. The information contained on our website is not part of this document.

Forward-Looking Information

This Form 10-K contains forward-looking statements as defined by the SEC. Forward-looking statements are all statements other than statements of historical fact, including without limitation those statements that are identified by the words “anticipates,” “estimates,” “expects,” “intends,” “plans,” “predicts” and similar expressions, and include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions and other statements that are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature, including statements contained within Item 7 - Management’s Discussion & Analysis of Financial Condition and Results of Operations.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. The Company’s expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including without limitation, management’s examination of historical operating trends, data contained in the Company’s records and other data available from third parties. Nonetheless, the Company’s expectations, beliefs or projections may not be achieved or accomplished.

Any forward-looking statement contained in this document speaks only as of the date on which the statement is made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company’s business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements in this Form 10-K, including statements contained within Item 1A - Risk Factors.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

History and Organization

Black Hills Corporation, a South Dakota corporation (together with its subsidiaries, referred to herein as the "Company," "we," "us" or "our"), is a growth-oriented, vertically-integrated energy company headquartered in Rapid City, South Dakota. Our predecessor company, Black Hills Power and Light Company, was incorporated and began providing electric utility service in 1941. It was formed through the purchase and combination of several existing electric utilities and related assets, some of which had served customers in the Black Hills region since 1883. In 1956, we began producing, selling and marketing various forms of energy through non-regulated businesses.

We operate principally in the United States with two major business groups: Utilities and Non-regulated Energy. Our Utilities Group is comprised of regulated Electric Utilities and regulated Gas Utilities segments, and our Non-regulated Energy Group is comprised of Power Generation, Coal Mining and Oil and Gas segments.

Business Group	Financial Segment
Utilities	Electric Utilities
	Gas Utilities
Non-regulated Energy	Power Generation
	Coal Mining
	Oil and Gas

Our Electric Utilities segment generates, transmits and distributes electricity to approximately 205,400 electric customers in South Dakota, Wyoming, Colorado and Montana and also distributes natural gas to approximately 36,000 gas utility customers of Cheyenne Light in and around Cheyenne, Wyoming. Our Gas Utilities segment serves approximately 543,200 natural gas utility customers in Colorado, Nebraska, Iowa and Kansas. Our Electric Utilities own 841 MW of generation and 8,660 miles of electric transmission and distribution lines, and our Gas Utilities own 645 miles of intrastate gas transmission pipelines and 19,058 miles of gas distribution mains and service lines. Our Utilities Group generated net income of $101 million for the year ended December 31, 2014, and had total assets of $3.7 billion at December 31, 2014.

Our Power Generation segment produces electric power from our generating plants and sells the electric capacity and energy primarily to our utilities under long-term contracts. Our Coal Mining segment produces coal at our coal mine near Gillette, Wyoming, and sells the coal primarily under long-term contracts to mine-mouth electric generation facilities including our own regulated and non-regulated generating plants. Our Oil and Gas segment engages in the exploration, development and production of crude oil and natural gas, primarily in the Rocky Mountain region. Our Non-regulated Energy Group generated net income of $28 million for the year ended December 31, 2014, and had total assets of $0.5 billion at December 31, 2014.

For more than 15 years, prior to February 2012, we also owned and operated Enserco, an energy marketing business that engaged in natural gas, crude oil, coal, power and environmental marketing and trading in the United States and Canada. On February 29, 2012, we sold Enserco, representing our entire Energy Marketing segment, which resulted in this segment being reclassified as discontinued operations. See Note 21 in the accompanying Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for further details.

Segment Financial Information

We discuss our business strategy and other prospective information in Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations. Financial information regarding our business segments is incorporated herein by reference to Item 8 - Financial Statements and Supplementary Data, and particularly Note 4 to the Consolidated Financial Statements, in this Annual Report on Form 10-K.

Discontinued Operations in the accompanying financial information includes the results of our Energy Marketing segment sold in February 2012.

Business Group Overview

Utilities Group

We conduct electric utility operations and combination electric and gas utility operations through three subsidiaries: Black Hills Power (South Dakota, Wyoming and Montana), Cheyenne Light (Wyoming), and Colorado Electric (Colorado). Our Electric Utilities generate, transmit and distribute electricity to approximately 205,400 customers; and also distribute natural gas to approximately 36,000 natural gas utility customers of Cheyenne Light in and around Cheyenne, Wyoming. Our electric generating facilities and power purchase agreements provide for the supply of electricity principally to our own distribution systems. Additionally, we sell excess power to other utilities and marketing companies, including our affiliates.

We conduct natural gas utility operations on a state-by-state basis through our Colorado Gas, Nebraska Gas, Iowa Gas and Kansas Gas subsidiaries. Our Gas Utilities distribute and transport natural gas through our distribution network to approximately 543,200 customers. Additionally, we sell temporarily-available, contractual pipeline capacity and gas commodities to other utilities and marketing companies, including our affiliates.

We also provide non-regulated services through our Service Guard and Tech Services product lines. Service Guard primarily provides appliance repair services to approximately 63,000 residential customers through company technicians and third party service providers, typically through on-going monthly service agreements. Tech Services primarily serves gas transportation customers throughout our service territory by constructing customer-owned gas infrastructure facilities, typically through one-time contracts, with a limited number of on-going monthly maintenance agreements. Tech Services also provides electrical system construction services to large industrial customers of our electric utilities.

Electric Utilities Segment

Capacity and Demand

System peak demands for the Electric Utilities for each of the last three years are listed below:

	System Peak Demand (in MW)					
	2014		2013		2012	
	Summer	Winter	Summer	Winter	Summer	Winter
Black Hills Power	410	389	422	403	449	362
Cheyenne Light	198	197	185	192	187	174
Colorado Electric	384	298	381	280	400	284
Total Electric Utilities Peak Demands	992	884	988	875	1,036	820

Regulated Power Plants

As of December 31, 2014, our Electric Utilities' ownership interests in electric generation plants were as follows:

Unit	Fuel Type	Location	Ownership Interest %	Owned Capacity (MW)	Year Installed
Black Hills Power [1]:					
Cheyenne Prairie [2]	Gas	Cheyenne, Wyoming	58%	55.0	2014
Wygen III [3]	Coal	Gillette, Wyoming	52%	57.2	2010
Neil Simpson II	Coal	Gillette, Wyoming	100%	90.0	1995
Wyodak [4]	Coal	Gillette, Wyoming	20%	72.4	1978
Neil Simpson CT	Gas	Gillette, Wyoming	100%	40.0	2000
Lange CT	Gas	Rapid City, South Dakota	100%	40.0	2002
Ben French Diesel #1-5	Oil	Rapid City, South Dakota	100%	10.0	1965
Ben French CTs #1-4	Gas/Oil	Rapid City, South Dakota	100%	80.0	1977-1979
Cheyenne Light:					
Cheyenne Prairie [2]	Gas	Cheyenne, Wyoming	42%	40.0	2014
Cheyenne Prairie CT [2]	Gas	Cheyenne, Wyoming	100%	37.0	2014
Wygen II	Coal	Gillette, Wyoming	100%	95.0	2008
Colorado Electric:					
Busch Ranch Wind Farm [5]	Wind	Pueblo, Colorado	50%	14.5	2012
Pueblo Airport Generation	Gas	Pueblo, Colorado	100%	180.0	2011
AIP Diesel	Oil	Pueblo, Colorado	100%	10.0	2001
Diesel #1-5	Oil	Pueblo, Colorado	100%	10.0	1964
Diesel #1-5	Oil	Rocky Ford, Colorado	100%	10.0	1964
Total MW Capacity				841.1	

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(1) The Osage, Ben French, and Neil Simpson I generating plants, having a combined capacity of 81.3 MW, were retired on March 21, 2014 due to the availability of more economical generation alternatives when evaluating costs to retrofit these plants to comply with environmental standards, including EPA regulations. The remaining net book value of these plants is deferred as a Regulatory asset on the accompanying Consolidated Balance Sheets. We have requested recovery for the remaining net book values of these plants and prudent decommissioning costs of these units. The WPSC granted approval to our request in the Wyoming rate case approved in August 2014, and our request with the SDPUC is pending with a decision expected in March 2015.

(2) Cheyenne Prairie, a 132 MW natural gas-fired power generation facility was placed into commercial operations on October 1, 2014 to support the customers of Black Hills Power and Cheyenne Light. The facility includes one simple-cycle, 37 MW combustion turbine that is wholly-owned by Cheyenne Light and one combined-cycle, 95 MW unit that is jointly-owned by Cheyenne Light (40 MW) and Black Hills Power (55 MW).

(3) Wygen III, a 110 MW mine-mouth coal-fired power plant, is operated by Black Hills Power. Black Hills Power has a 52% ownership interest, MDU owns 25% and the City of Gillette owns the remaining 23% interest. Our WRDC coal mine supplies all of the fuel for the plant.

(4) Wyodak, a 362 MW mine-mouth coal-fired power plant, is owned 80% by PacifiCorp and 20% by Black Hills Power. This baseload plant is operated by PacifiCorp and our WRDC coal mine supplies all of the fuel for the plant.

(5) Busch Ranch Wind Farm, a 29 MW wind farm, is operated by Colorado Electric. Colorado Electric has a 50% ownership interest in the wind farm and AltaGas owns the remaining 50%. Colorado Electric has a 25-year REPA with AltaGas for their 14.5 MW of power from the wind farm. The wind farm became operational October 16, 2012.

The Electric Utilities' annual average cost of fuel utilized to generate electricity and the average price paid for purchased power (excluding contracted capacity) per MWh for the years ended December 31 is as follows:

Fuel Source (dollars per megawatt-hour)	2014	2013	2012
Coal	$10.92	$10.89	$14.42
Natural Gas	$77.31	$53.53	$52.08
Diesel Oil	$174.04	$233.47	$280.29
Total Average Fuel Cost	$14.82	$14.65	$16.05
Purchased Power - Coal, Gas and Oil	$35.21	$29.95	$26.70
Purchased Power - Renewable Sources	$50.27	$49.20	$47.45

Our Electric Utilities' power supply, by resource as a percent of the total power supply for our energy needs for the years ended December 31 is as follows:

Power Supply	2014	2013	2012
Coal	34 %	36 %	37 %
Gas, Oil and Wind	4	4	2
Total Generated	38	40	39
Purchased	62	60	61
Total	100 %	100 %	100 %

Purchased Power. We have executed various agreements to support our Electric Utilities' capacity and energy needs beyond our regulated power plants' generation. Key contracts include:

- Black Hills Power's PPA with PacifiCorp expiring on December 31, 2023, which provides for the purchase of 50 MW of coal-fired baseload power;

- Colorado Electric's PPA with Black Hills Colorado IPP expiring on December 31, 2031, which provides 200 MW of energy and capacity to Colorado Electric from Black Hills Colorado IPP's combined-cycle turbines. This PPA is accounted for as a capital lease on the accompanying Consolidated Financial Statements;

- Colorado Electric's PPA with Cargill expiring on December 31, 2015, which provides for the purchase of 50 MW of energy during heavy load timing intervals;

- Colorado Electric's PPA with Cargill expiring on December 31, 2016, which provides for the purchase of 50 MW of energy during light load timing intervals;

- Colorado Electric's PPA with AltaGas expiring on October 16, 2037, which provides up to 14.5 MW of wind energy from AltaGas' owned interest in the Busch Ranch Wind Project;

- Cheyenne Light's PPA with Black Hills Wyoming expiring on December 31, 2022, whereby Black Hills Wyoming provides 60 MW of unit-contingent capacity and energy from its Wygen I facility. The PPA includes an option for Cheyenne Light to purchase Black Hills Wyoming's ownership interest in the Wygen I facility through 2019. The purchase price related to the option is $2.6 million per MW adjusted for capital additions and reduced by depreciation over a 35-year life beginning January 1, 2009 (approximately $5 million per year);

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Cheyenne Light's 20-year PPA with Duke Energy expiring on September 3, 2028, which provides up to 29.4 MW of wind energy from the Happy Jack Wind Farm to Cheyenne Light. Under a separate inter-company agreement, Cheyenne Light sells 50% of the facility's output to Black Hills Power;

- Cheyenne Light's 20-year PPA with Duke Energy expiring on September 30, 2029, which provides up to 30 MW of wind energy from the Silver Sage wind farm to Cheyenne Light. Under a separate inter-company agreement, Cheyenne Light sells 20 MW of energy from Silver Sage to Black Hills Power; and

- Cheyenne Light and Black Hills Power's Generation Dispatch Agreement requires Black Hills Power to purchase all of Cheyenne Light's excess energy.

Power Sales Agreements. Our Electric Utilities have various long-term power sales agreements. Key agreements include:

- MDU owns a 25% interest in Wygen III's net generating capacity for the life of the plant. During periods of reduced production at Wygen III, or during periods when Wygen III is off-line, Black Hills Power will provide MDU with 25 MW from its other generation facilities or from system purchases with reimbursement of costs by MDU;

- Black Hills Power has an agreement through December 31, 2023 to serve MDU capacity and energy up to a maximum of 50 MW.

- The City of Gillette owns a 23% interest in Wygen III's net generating capacity for the life of the plant. During periods of reduced production at Wygen III, or during periods when Wygen III is off-line, Black Hills Power will provide the City of Gillette with its first 23 MW from its other generation facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement, Black Hills Power will also provide the City of Gillette its operating component of spinning reserves;

- Black Hills Power's agreement to supply up to 20 MW of energy and capacity to MEAN under a contract that expires in 2023. This contract is unit-contingent based on the availability of our Neil Simpson II and Wygen III plants, with decreasing capacity purchased over the term of the agreement. The unit-contingent capacity amounts from Wygen III and Neil Simpson II are as follows:

2015-2017	20 MW - 10 MW contingent on Wygen III and 10 MW contingent on Neil Simpson II
2018-2019	15 MW - 10 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II
2020-2021	12 MW - 6 MW contingent on Wygen III and 6 MW contingent on Neil Simpson II
2022-2023	10 MW - 5 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II; and

- Black Hills Power's PPA with MEAN, whereby MEAN will purchase 5 MW of unit-contingent capacity from Neil Simpson II and 5 MW of unit-contingent capacity from Wygen III through May 2015.

Transmission and Distribution. Through our Electric Utilities, we own electric transmission systems composed of high voltage transmission lines (greater than 69 kV) and low voltage lines (69 kV or less). We also jointly own high voltage lines with Basin Electric and Powder River Energy Corporation.

At December 31, 2014, our Electric Utilities owned the electric transmission and distribution lines shown below:

Utility	State	Transmission (in Line Miles)	Distribution (in Line Miles)
Black Hills Power	South Dakota, Wyoming	1,182	2,474
Black Hills Power - Jointly Owned (1)	South Dakota, Wyoming	44	—
Cheyenne Light	South Dakota, Wyoming	48	1,257
Colorado Electric	Colorado	585	3,070

(1) Black Hills Power owns 35% of a DC transmission tie that interconnects the Western and Eastern transmission grids, which are independently-operated transmission grids serving the western United States and eastern United States, respectively. This transmission tie, which is 65% owned by Basin Electric, provides transmission access to

both the WECC region in the West and the MAPP region in the East. The transfer capacity of the tie is 200 MW from West to East, and 200 MW from East to West. Black Hills Power's electric system is located in the WECC region. This transmission tie allows us to buy and sell energy in the Eastern grid without having to isolate and physically reconnect load or generation between the two transmission grids, thus enhancing the reliability of our system. It accommodates scheduling transactions in both directions simultaneously, provides additional opportunities to sell excess generation or to make economic purchases to serve our native load and contract obligations, and enables us to take advantage of power price differentials between the two grids.

Black Hills Power has firm point-to-point transmission access to deliver up to 50 MW of power on PacifiCorp's transmission system to wholesale customers in the WECC region through 2023.

Black Hills Power also has firm network transmission access to deliver power on PacifiCorp's system to Sheridan, Wyoming, to serve our power sales contract with MDU through 2017, with the right to renew pursuant to the terms of PacifiCorp's transmission tariff.

In order to serve Cheyenne Light's existing load, Cheyenne Light has a network transmission agreement with Western Area Power Association's Loveland Area Project.

Operating Agreements. Our Electric Utilities have the following material operating agreements:

- Shared Services Agreements -

Black Hills Power, Cheyenne Light, and Black Hills Wyoming are parties to a shared facilities agreement, whereby each entity charges for the use of assets by the affiliate entity.
Black Hills Colorado IPP and Colorado Electric are also parties to a facility fee agreement, whereby Colorado Electric charges Black Hills Colorado IPP for the use of Colorado Electric assets.
Black Hills Power and Cheyenne Light also receive certain staffing and management services from BHSC for Cheyenne Prairie.

- Jointly Owned Facilities -

Black Hills Power, the City of Gillette and MDU are parties to a shared joint ownership agreement, whereby Black Hills Power charges the City of Gillette and MDU for administrative services, plant operations and maintenance for their share of the Wygen III generating facility for the life of the plant.
Colorado Electric and AltaGas are parties to a shared joint ownership agreement whereby Colorado Electric charges AltaGas for operations and maintenance for their share of the Busch Ranch Wind Farm.

Operating Statistics

The following tables summarize information for our Electric Utilities:

Degree Days	2014		2013		2012	
	Actual	Variance from 30-Year Average (b)	Actual	Variance from 30-Year Average (b)	Actual	Variance from 30-Year Average (b)
Heating Degree Days:						
Black Hills Power	7,373	4%	7,582	9%	6,206	(13)%
Cheyenne Light	7,100	—%	7,386	4%	6,304	(11)%
Colorado Electric	5,534	—%	5,740	1%	4,921	(13)%
Combined (a)	6,473	2%	6,691	5%	5,629	(12)%
Cooling Degree Days:						
Black Hills Power	481	(28)%	724	8%	937	47%
Cheyenne Light	336	(5)%	520	48%	568	63%
Colorado Electric	919	(4)%	1,230	28%	1,322	47%
Combined (a)	654	(12)%	918	7%	1,043	47%

(a) The combined heating degree days are calculated based on a weighted average of total customers by state.

(b) 30-Year Average is from NOAA Climate Normals.

Revenue - Electric (in thousands)	2014	2013	2012
Residential:			
Black Hills Power	$69,712	$64,566	$58,523
Cheyenne Light	36,634	35,778	32,053
Colorado Electric [(a)]	94,391	95,631	91,550
Total Residential	200,737	195,975	182,126
Commercial:			
Black Hills Power	91,882	80,289	73,858
Cheyenne Light	59,758	57,444	55,600
Colorado Electric	90,909	87,732	82,849
Total Commercial	242,549	225,465	212,307
Industrial:			
Black Hills Power	28,451	27,705	25,656
Cheyenne Light	29,066	20,803	16,105
Colorado Electric	39,219	38,037	37,540
Total Industrial	96,736	86,545	79,301
Municipal:			
Black Hills Power	3,409	3,421	3,268
Cheyenne Light	1,930	1,918	1,807
Colorado Electric	13,312	13,106	13,373
Total Municipal	18,651	18,445	18,448
Subtotal Retail Revenue - Electric	558,673	526,430	492,182
Contract Wholesale:			
Total Contract Wholesale - Black Hills Power	21,206	21,956	20,290
Off-system/Power Marketing Wholesale:			
Black Hills Power	28,002	29,580	31,905
Cheyenne Light	8,179	8,712	8,365
Colorado Electric	5,726	8,329	6,003
Total Off-system/Power Marketing Wholesale	41,907	46,621	46,273
Other Revenue: [(b)]			
Black Hills Power	25,826	26,510	29,809
Cheyenne Light	2,253	1,916	2,336
Colorado Electric [(c)]	7,691	4,612	4,652
Total Other Revenue	35,770	33,038	36,797
Total Revenue - Electric	$657,556	$628,045	$595,542

(a) 2013 includes $0.7 million and 2012 includes $2.1 million in construction savings incentives from the construction of the Pueblo Airport Generating Station.

(b) Other revenue primarily consists of transmission revenue.

(c) Increase in 2014 is primarily due to $1.8 million in technical service revenues for facility improvements at one of our large industrial customers.

Quantities Generated and Purchased (MWh)	2014	2013	2012
Generated -			
Coal-fired:			
Black Hills Power [(a)]	1,591,061	1,768,483	1,796,936
Cheyenne Light	697,220	688,318	587,832
Colorado Electric [(b)]	—	—	222,647
Total Coal - fired	2,288,281	2,456,801	2,607,415
Natural Gas and Oil:			
Black Hills Power [(c)]	44,984	33,374	33,183
Cheyenne Light [(c)]	12,534	—	—
Colorado Electric [(d)]	140,942	247,758	84,874
Total Natural Gas and Oil	198,460	281,132	118,057
Wind:			
Colorado Electric	48,318	45,765	12,433
Total Wind	48,318	45,765	12,433
Total Generated:			
Black Hills Power	1,636,045	1,801,857	1,830,119
Cheyenne Light	709,754	688,318	587,832
Colorado Electric	189,260	293,523	319,954
Total Generated	2,535,059	2,783,698	2,737,905
Purchased -			
Black Hills Power	1,446,630	1,441,286	1,678,090
Cheyenne Light	766,475	779,677	807,659
Colorado Electric	1,898,232	1,886,627	1,794,229
Total Purchased [(e)]	4,111,337	4,107,590	4,279,978
Total Generated and Purchased	6,646,396	6,891,288	7,017,883

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(a) Neil Simpson I was retired on March 21, 2014.
(b) W.N. Clark suspended operations in 2012.
(c) Cheyenne Prairie was placed into commercial service on October 1, 2014.
(d) Decrease in 2014 generation primarily due to increased commodity prices that impacted power marketing sales.
(e) Includes wind power of 224,229 MWh, 222,069 MWh, and 199,079 MWh in 2014, 2013 and 2012, respectively.

Quantities (MWh)	2014	2013	2012
Residential:			
Black Hills Power	542,008	555,204	532,342
Cheyenne Light	261,038	272,490	261,792
Colorado Electric	598,872	619,857	614,521
Total Residential	1,401,918	1,447,551	1,408,655
Commercial:			
Black Hills Power	782,238	730,701	731,785
Cheyenne Light	528,689	544,636	577,141
Colorado Electric	685,094	703,604	723,216
Total Commercial	1,996,021	1,978,941	2,032,142
Industrial:			
Black Hills Power	399,648	404,009	407,301
Cheyenne Light	382,306	281,727	224,448
Colorado Electric	432,167	371,102	358,490
Total Industrial	1,214,121	1,056,838	990,239
Municipal:			
Black Hills Power	32,076	34,344	35,933
Cheyenne Light	9,425	9,848	9,631
Colorado Electric	122,247	114,732	121,480
Total Municipal	163,748	158,924	167,044
Subtotal Retail Quantity Sold	4,775,808	4,642,254	4,598,080
Contract Wholesale:			
Total Contract Wholesale - Black Hills Power	340,871	357,193	340,036
Off-system Wholesale:			
Black Hills Power	808,257	1,002,847	1,263,457
Cheyenne Light	191,069	234,566	229,062
Colorado Electric	119,315	219,349	160,430
Total Off-system Wholesale	1,118,641	1,456,762	1,652,949
Total Quantity Sold:			
Black Hills Power	2,905,098	3,084,298	3,310,854
Cheyenne Light	1,372,527	1,343,267	1,302,074
Colorado Electric	1,957,695	2,028,644	1,978,137
Total Quantity Sold	6,235,320	6,456,209	6,591,065
Other Uses, Losses or Generation, net [(a)]:			
Black Hills Power	177,577	158,845	197,355
Cheyenne Light	103,702	124,728	93,417
Colorado Electric	129,797	151,506	136,046
Total Other Uses, Losses and Generation, net	411,076	435,079	426,818
Total Energy	6,646,396	6,891,288	7,017,883

(a) Includes company uses, line losses, test energy and excess exchange production.

Customers at End of Year	2014	2013	2012
Residential:			
Black Hills Power	56,511	55,840	55,296
Cheyenne Light	36,253	35,780	35,438
Colorado Electric	82,710	82,371	81,795
Total Residential	175,474	173,991	172,529
Commercial:			
Black Hills Power [(a)]	13,173	12,888	12,857
Cheyenne Light	4,489	4,471	4,276
Colorado Electric	11,156	11,060	11,220
Total Commercial	28,818	28,419	28,353
Industrial:			
Black Hills Power [(a)]	23	46	44
Cheyenne Light	4	3	2
Colorado Electric	66	61	61
Total Industrial	93	110	107
Other Electric Customers:			
Black Hills Power	325	310	308
Cheyenne Light	224	232	240
Colorado Electric	469	469	475
Total Other Electric Customers	1,018	1,011	1,023
Subtotal Retail Customers	205,403	203,531	202,012
Contract Wholesale:			
Total Contract Wholesale - Black Hills Power	3	3	3
Total Customers:			
Black Hills Power	70,035	69,087	68,508
Cheyenne Light	40,970	40,486	39,956
Colorado Electric	94,401	93,961	93,551
Total Electric Customers at End of Year	205,406	203,534	202,015

(a) Change in customers is due to classification change to Commercial billing in 2014 based on customer’s business type.

Cheyenne Light Natural Gas Distribution

Included in the Electric Utilities is Cheyenne Light's natural gas distribution system. The following table summarizes certain operating information for the natural gas distribution operations of Cheyenne Light:

	2014	2013	2012
Revenue - Gas (in thousands):			
Residential	$24,426	$23,047	$19,327
Commercial	11,279	10,326	8,613
Industrial	2,945	3,050	2,715
Other Sales Revenue	1,104	840	769
Total Revenue - Gas	$39,754	$37,263	$31,424
Gross Margin - Gas (in thousands):			
Residential	$11,615	$12,706	$10,712
Commercial	3,582	3,993	2,963
Industrial	525	598	551
Other Gross Margin	1,104	881	766
Total Gross Margin - Gas	$16,826	$18,178	$14,992
Quantities Sold (Dth):			
Residential	2,515,243	2,728,797	2,215,858
Commercial	1,482,904	1,653,021	1,447,522
Industrial	539,848	652,539	598,408
Total Quantities Sold	4,537,995	5,034,357	4,261,788
Gas Customers at Year-End	36,033	35,494	35,021

Gas Utilities Segment

The following tables summarize certain operating information for our Gas Utilities.

System Infrastructure (in line miles) as of December 31, 2014	Intrastate Gas Transmission Pipelines	Gas Distribution Mains	Gas Distribution Service Lines
Colorado	126	3,030	942
Nebraska	44	3,482	2,474
Iowa	182	2,690	2,373
Kansas	293	2,755	1,312
Total	645	11,957	7,101

Degree Days

	2014		2013		2012	
	Actual	Variance From 30-Year Average (c)	Actual	Variance From 30-Year Average (c)	Actual	Variance From 30-Year Average (c)
Heating Degree Days:						
Colorado	6,108	(3)%	6,310	1%	5,186	(18)%
Nebraska	6,193	2%	6,516	8%	5,198	(15)%
Iowa	7,875	16%	7,743	14%	6,093	(10)%
Kansas [a]	5,099	4%	5,294	8%	4,190	(15)%
Combined [b]	6,780	7%	6,922	9%	5,518	(13)%

(a) Kansas Gas has an approved weather normalization mechanism within its rate structure, which minimizes weather impact on gross margins.

(b) The combined heating degree days are calculated based on a weighted average of total customers by state excluding Kansas Gas due to its weather normalization mechanism.

(c) 30-Year Average is from NOAA climate normals.

Operating Statistics			
Revenue (in thousands)	2014	2013	2012
Residential:			
Colorado	$58,439	$53,296	$48,406
Nebraska	135,052	122,197	98,339
Iowa	124,145	98,498	82,669
Kansas	74,128	67,501	55,096
Total Residential	391,764	341,492	284,510
Commercial:			
Colorado	12,233	10,515	9,558
Nebraska	39,947	37,190	30,894
Iowa	60,640	47,494	36,550
Kansas	24,966	21,440	15,677
Total Commercial	137,786	116,639	92,679
Industrial:			
Colorado	1,909	1,661	1,963
Nebraska	830	900	876
Iowa	4,386	3,436	2,458
Kansas	16,963	15,753	13,614
Total Industrial	24,088	21,750	18,911
Other:			
Colorado	118	(17)	181
Nebraska	2,440	2,265	2,066
Iowa	724	543	452
Kansas	2,836	2,326	5,124
Total Other Sales Revenue	6,118	5,117	7,823
Distribution:			
Colorado	72,699	65,455	60,108
Nebraska	178,269	162,552	132,175
Iowa	189,895	149,971	122,129
Kansas	118,893	107,020	89,511
Total Distribution	559,756	484,998	403,923
Transportation:			
Colorado	968	1,033	866
Nebraska	14,272	12,943	10,589
Iowa	4,934	4,809	4,128
Kansas	7,448	6,472	5,762
Total Transportation	27,622	25,257	21,345
Total Regulated Revenue	587,378	510,255	425,268
Non-regulated Services	30,390	29,434	28,813
Total Revenue	$617,768	$539,689	$454,081

Gross Margin (in thousands)	2014	2013	2012
Residential:			
Colorado	$18,100	$18,244	$16,400
Nebraska	54,996	53,367	46,982
Iowa	44,134	42,961	39,561
Kansas	32,809	32,111	28,734
Total Residential	150,039	146,683	131,677
Commercial:			
Colorado	3,048	3,009	2,680
Nebraska	11,708	11,560	10,201
Iowa	13,206	13,060	11,071
Kansas	8,115	7,436	6,097
Total Commercial	36,077	35,065	30,049
Industrial:			
Colorado	464	519	581
Nebraska	239	250	249
Iowa	294	321	257
Kansas	2,336	2,220	2,362
Total Industrial	3,333	3,310	3,449
Other:			
Colorado	118	(17)	181
Nebraska	2,441	2,266	2,066
Iowa	724	543	452
Kansas	1,990	1,723	4,787
Total Other Sales Margins	5,273	4,515	7,486
Distribution:			
Colorado	21,730	21,755	19,842
Nebraska	69,384	67,443	59,498
Iowa	58,358	56,885	51,341
Kansas	45,250	43,490	41,980
Total Distribution	194,722	189,573	172,661
Transportation:			
Colorado	968	1,033	866
Nebraska	14,272	12,943	10,589
Iowa	4,934	4,809	4,128
Kansas	7,448	6,472	5,762
Total Transportation	27,622	25,257	21,345
Total Regulated Gross Margin:			
Colorado	22,698	22,788	20,708
Nebraska	83,656	80,386	70,087
Iowa	63,292	61,694	55,469
Kansas	52,698	49,962	47,742
Total Regulated Gross Margin	222,344	214,830	194,006

Non-regulated Services	14,572	14,396	14,726
Total Gross Margin	$236,916	$229,226	$208,732

Distribution Quantities Sold and Transportation (in Dth)	2014	2013	2012
Residential:			
Colorado	6,718,508	6,969,741	5,869,817
Nebraska	13,068,132	12,717,565	9,555,073
Iowa	12,172,281	11,359,220	8,732,301
Kansas	7,313,273	7,174,085	5,681,199
Total Residential	39,272,194	38,220,611	29,838,390
Commercial:			
Colorado	1,537,704	1,506,227	1,284,082
Nebraska	4,644,645	4,770,370	3,952,067
Iowa	7,182,173	7,056,978	5,304,162
Kansas	3,043,685	2,867,696	2,121,063
Total Commercial	16,408,207	16,201,271	12,661,374
Industrial:			
Colorado	354,630	405,047	463,566
Nebraska	122,662	150,227	158,445
Iowa	630,912	648,173	492,633
Kansas	3,384,797	3,355,930	3,675,678
Total Industrial	4,493,001	4,559,377	4,790,322
Wholesale and Other:			
Kansas	150,014	116,234	68,419
Total Wholesale and Other	150,014	116,234	68,419
Distribution Quantities Sold:			
Colorado	8,610,842	8,881,015	7,617,465
Nebraska	17,835,439	17,638,162	13,665,585
Iowa	19,985,366	19,064,371	14,529,096
Kansas	13,891,769	13,513,945	11,546,359
Total Distribution Quantities Sold	60,323,416	59,097,493	47,358,505
Transportation:			
Colorado	950,819	1,015,791	850,156
Nebraska	30,669,764	28,171,610	26,649,759
Iowa	19,959,462	20,176,525	18,294,228
Kansas	15,883,098	14,457,620	14,686,679
Total Transportation	67,463,143	63,821,546	60,480,822
Total Distribution Quantities Sold and Transportation:			
Colorado	9,561,661	9,896,806	8,467,621
Nebraska	48,505,203	45,809,772	40,315,344
Iowa	39,944,828	39,240,896	32,823,324
Kansas	29,774,867	27,971,565	26,233,038
Total Distribution Quantities Sold and Transportation	127,786,559	122,919,039	107,839,327

Customers at End of Year	2014	2013	2012
Residential:			
Colorado	72,360	70,410	68,927
Nebraska	180,014	178,389	176,953
Iowa	138,503	137,525	135,897
Kansas	99,359	99,315	98,516
Total Residential	490,236	485,639	480,293
Commercial:			
Colorado	3,788	3,737	3,681
Nebraska	15,900	15,739	15,626
Iowa	15,303	15,418	15,398
Kansas	10,547	9,832	9,584
Total Commercial	45,538	44,726	44,289
Industrial:			
Colorado	205	207	213
Nebraska	147	136	136
Iowa	90	94	94
Kansas	1,277	1,358	1,261
Total Industrial	1,719	1,795	1,704
Transportation:			
Colorado	34	36	36
Nebraska	4,151	4,240	4,115
Iowa	418	421	412
Kansas	1,145	1,171	1,166
Total Transportation	5,748	5,868	5,729
Wholesale:			
Kansas	8	7	7
Total Wholesale	8	7	7
Total Customers:			
Colorado	76,387	74,390	72,857
Nebraska	200,212	198,504	196,830
Iowa	154,314	153,458	151,801
Kansas	112,336	111,683	110,534
Total Customers at End of Year	543,249	538,035	532,022

Utilities Group Business Characteristics

Seasonal Variations of Business

Our Electric Utilities and Gas Utilities are seasonal businesses and weather patterns may impact their operating performance. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as market price. In particular, demand is often greater in the summer and winter months for cooling and heating, respectively. Because our Electric Utilities have a diverse customer and revenue base, and we have historically optimized the utilization of our electric power supply resources, the impact on our operations may not be as significant when weather conditions are warmer in the winter and cooler in the summer. Conversely, for our Gas Utilities, natural gas is used primarily for residential and commercial heating, so the demand for this product depends heavily upon weather throughout our service territories, and as a result, a significant amount of natural gas revenue is normally recognized in the heating season consisting of the first and fourth quarters.

Competition

We generally have limited competition for the retail distribution of electricity and natural gas in our service areas. Various restructuring and competitive initiatives have been discussed in several of the states in which our utilities operate. These initiatives would be aimed at increasing competition or providing for distributed generation. To date, there has been no material impact to our utilities. Although we face competition from independent marketers for the sale of natural gas to our industrial and commercial customers, in instances where independent marketers displace us as the seller of natural gas, we still collect a distribution charge for transporting the gas through our distribution network. In Colorado, our electric utility is subject to rules which may require competitive bidding for generation supply. Because of these rules, we face competition from other utilities and non-affiliated independent power producers for the right to provide electric energy and capacity for Colorado Electric when resource plans require additional resources.

Rates and Regulation

Current Rates

Our utilities are subject to the jurisdiction of the public utilities commissions in the states where they operate. The commissions oversee services and facilities, rates and charges, accounting, valuation of property, depreciation rates and various other matters. The public utility commissions determine the rates we are allowed to charge for our utility services. Rate decisions are influenced by many factors, including the cost of providing service, capital expenditures, the prudence of costs we incur, views concerning appropriate rates of return, the rates of other utilities, general economic conditions and the political environment. Certain commissions also have jurisdiction over the issuance of debt or securities, and the creation of liens on property located in their states to secure bonds or other securities.

The following table illustrates information about certain enacted regulatory provisions with respect to the states in which the Utilities Group operates:

Subsidiary	Jurisdic-tion	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Tariff and Rate Matters	Percentage of Power Marketing Activity Shared with Customers
Electric Utilities:								
Black Hills Power	WY	9.9%	8.13%	46.7%/53.3%	$46.8	10/2014	ECA	65%
	SD	Global Settlement	7.93%	Global Settlement	$440.2	6/2013	ECA, TCA, Energy Efficiency Cost Recovery/DSM	65%
	SD		8.16%			6/2011	Environmental Improvement Cost Recovery Adjustment Tariff	N/A
	MT	15.0%	11.7%	47%/53%		1983	ECA	N/A
	FERC	10.8%	9.1%	43%/57%		2/2009	FERC Transmission Tariff	N/A
Cheyenne Light - Electric	WY	9.9%	7.98%	46%/54%	$376.8	10/2014	PCA, Energy Efficiency Cost Recovery/DSM, Rate Base Recovery on Acquisition Adjustment	N/A
	FERC	10.6%	8.51%	46%/54%	$31.5	5/2014	FERC Transmission Tariff	N/A
Cheyenne Light - Gas	WY	9.9%	7.98%	46%/54%	$59.6	10/2014	GCA, Energy Efficiency Cost Recovery/DSM, Rate Base Recovery on Acquisition Adjustment	N/A
Colorado Electric	CO	9.83%	7.55%	50.2%/49.8%	$448.3	1/2015	ECA, TCA, PCCA, Energy Efficiency Cost Recovery/DSM, Renewable Energy Standard Adjustment, Construction Rider	90%
Gas Utilities:								
Colorado Gas	CO	9.6%	8.4%	50%/50%	$64.0	12/2012	GCA, Energy Efficiency Cost Recovery/DSM	N/A
Nebraska Gas	NE	10.1%	9.1%	48%/52%	$161.0	9/2010	GCA, Cost of Bad Debt Collected through GCA, Infrastructure System Replacement Cost Recovery Surcharge	N/A
Kansas Gas	KS	Global Settlement	Global Settlement	Global Settlement	$127.4	1/2015	GCA, Weather Normalization Tariff,	N/A

							Gas System Reliability Surcharge, Ad Valorem Tax Surcharge, Cost of Bad Debt Collected through GCA	
Iowa Gas	IA	Global Settlement	Global Settlement	Global Settlement	$110.2	2/2011	GCA, Energy Efficiency Cost Recovery/DSM/Capital Infrastructure Automatic Adjustment Mechanism	N/A

We produce and/or distribute electricity in four states: Colorado, South Dakota, Wyoming and Montana. The regulatory provisions for recovering the costs to supply electricity vary by state. In all states, subject to thresholds noted below, we have cost adjustment mechanisms for our Electric Utilities that allow us to pass the prudently-incurred cost of fuel and purchased power through to customers. These mechanisms allow the utility operating in that state to collect, or refund, the difference between the cost of commodities and certain services embedded in our base rates and the actual cost of the commodities and certain services without filing a general rate case. Some states in which our utilities operate also allow the utility operating in that state to automatically adjust rates periodically for the cost of new transmission or environmental improvements and, in some instances, the utility has the opportunity to earn its authorized return on new capital investment immediately.

Some of the mechanisms we have in place include the following:

- In Wyoming, Cheyenne Light has an annual cost adjustment mechanism that allows us to pass the prudently-incurred costs of fuel and purchased power through to electric customers. Until October 1, 2014, at Cheyenne Light, our pass-through sharing mechanism relating to transmission and the PCA, returned 85% to the customer, and the Company retained 15%. Effective October 1, 2014, coal and coal related costs are passed through under an 85% / 15% distribution methodology, and purchased power costs, transmission, and natural gas costs are passed through under a 95% / 5% distribution methodology.

- In South Dakota, Black Hills Power has an annual adjustment clause which provides for the direct recovery of increased fuel and purchased power cost incurred to serve South Dakota customers. Additionally, the ECA contains an off-system sales sharing mechanism in which South Dakota customers will receive a credit equal to 65% of off-system power marketing operating income. The modification also adjusts the methodology to directly assign renewable resources and firm purchases to the customer load. In Wyoming a similar fuel and purchased power cost adjustment is also in place.

- In South Dakota, we have an approved annual Environmental Improvement Cost Recovery Adjustment tariff that went into effect June 1, 2011, which recovers costs associated with generation plant environmental improvements.

- We have an approved FERC Transmission Tariff based on a formulaic approach that determines the revenue component of Black Hills Power's open access transmission tariff.

- We have an approved FERC Transmission Tariff that determines the revenue component of Cheyenne Light's open access transmission tariff.

- In Colorado, we have a quarterly ECA rider (the rider was semi-annual until August 1, 2013) that allows us to recover forecasted increases or decreases in purchased energy and fuel costs, including the recovery for amounts payable to others for the transmission of the utility's electricity over transmission facilities owned by others, symmetrical interest, and the sharing of off-system sales margins, less certain operating costs (customer receives 90%). Through 2013, this sharing percentage allowed 75% to the customers. The ECA provides for not only direct recovery, but also for the issuance of credits for decreases in purchased energy, fuel costs and eligible energy resources. Additionally, Colorado allows an annual TCA rider, that includes nine months of actual transmission investment and three months of forecasted investment, with an annual true-up mechanism.

- On December 19, 2014, Colorado Electric received approval from the CPUC to implement a rider effective January 1, 2015 to recover a return on the construction costs of a $65 million natural gas-fired combustion turbine that will replace the retired W.N. Clark power plant.

We distribute natural gas in five states: Colorado, Iowa, Nebraska, Kansas and Wyoming. All of our Gas Utilities and Cheyenne Light's natural gas distribution, have GCAs that allow us to pass the prudently-incurred cost of gas and certain services through to the customer between rate cases. Some of the mechanisms we have in place include the following:

- In Kansas, we have a tariff pass-through mechanism for weather normalization, as well as tariffs that provide timely recovery of certain capital expenditures and property tax fluctuations.

- In Kansas and Nebraska, we are allowed to recover the portion of uncollectible accounts related to gas costs through GCAs.

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In Iowa, we have a Capital Infrastructure Automatic Adjustment Mechanism that allows for recovery of certain capital infrastructure investments.

- In Nebraska, we have an Infrastructure System Replacement Cost mechanism that allows for recovery of certain capital infrastructure investments.

Pending Rates and Rate Activity

The following table summarizes recent activity of certain state and federal rate cases, riders and surcharges (dollars in millions):

	Type of Service	Date Requested	Effective Date	Revenue Amount Requested	Revenue Amount Approved
Cheyenne Light [(a)]	Electric/Gas	12/2013	10/2014	$14.1	$9.2
Black Hills Power [(b)]	Electric	1/2014	10/2014	$2.8	$2.2
Black Hills Power [(c)]	Electric	3/2014	10/2014	$14.6	pending
Iowa Gas [(d)]	Gas	2/2014	4/2014	$0.5	$0.5
Kansas Gas [(e)]	Gas	4/2014	1/2015	$7.3	$5.2
Colorado Electric [(f)]	Electric	4/2014	1/2015	$4.0	$3.1

(a) On July 31, 2014, the WPSC approved rate case settlement agreements authorizing an increase for Cheyenne Light of $8.4 million and $0.8 million for annual electric and natural gas revenue, respectively, effective October 1, 2014. The settlement also included a return on equity of 9.9% and a capital structure of 54% equity and 46% debt. The WPSC's decision provides Cheyenne Light a return on its investment in Cheyenne Prairie and associated infrastructure, and provides recovery of its share of operating expenses for this natural gas-fired facility.

(b) On August 21, 2014, the WPSC approved rate case settlement agreements authorizing an increase for Black Hills Power of approximately $2.2 million for annual electric revenue, effective October 1, 2014. The settlement also included a return on equity of 9.9% and a capital structure of 53.3% equity and 46.7% debt. The WPSC's decision provides Black Hills Power a return on its investment in Cheyenne Prairie and associated infrastructure and provides recovery of its share of operating expenses for this natural gas-fired facility.

(c) On March 31, 2014, Black Hills Power filed a rate request with the SDPUC to increase annual revenue by $14.6 million to recover operating expenses and infrastructure investments, primarily for Cheyenne Prairie. The filing seeks a return on equity of 10.25% and a capital structure of approximately 53.3% equity and 46.7% debt. Black Hills Power implemented interim rates on October 1, 2014, coinciding with Cheyenne Prairie's commercial operation date. We expect a final decision from the SDPUC on our rate request by the end of the first quarter of 2015. Interim rates will be trued up as necessary based on the final approval.

(d) On April 15, 2014, the IUB approved a capital investment recovery surcharge increase of $0.5 million.

(e) On April 29, 2014, Kansas Gas filed a rate request with the KCC to increase annual revenue to recover infrastructure and increased operating costs. On October 24, 2014, a settlement agreement was reached between Kansas Gas, the KCC and intervenors to increase base rates by $5.2 million. On December 16, 2014, Kansas Gas received approval from the KCC to increase base rates by $5.2 million.

(f) On April 30, 2014, Colorado Electric filed a rate request with the CPUC to recover increased operating expenses and infrastructure investments, including those for the Busch Ranch Wind Farm, placed in service late 2012. The filing also requested to implement a rider to recover a return on the construction costs for a $65 million natural gas-fired combustion turbine that will replace the retired W.N. Clark power plant. On December 19, 2014, Colorado Electric received approval from the CPUC for an annual electric revenue increase of $3.1 million. The approval also allowed a 9.83% return on equity and a capital structure of 49.83% equity and 50.17% debt, as well as approving implementation of the rider.

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Other State Regulations

Certain states where we conduct electric utility operations have adopted renewable energy portfolio standards that require or encourage our Electric Utilities to source, by a certain future date, a minimum percentage of the electricity delivered to customers from renewable energy generation facilities. At December 31, 2014, we were subject to the following renewable energy portfolio standards or objectives:

- Colorado. Colorado adopted a renewable energy standard that has two components: (i) electric resource standards and (ii) a 2% retail rate impact for compliance with the electric resource standards. The electric resource standards require our Colorado Electric subsidiary to generate, or cause to be generated, electricity from renewable energy sources equaling: (i) 20% of retail sales from 2015 to 2019; and (ii) 30% of retail sales by 2020. Of these amounts, 3% must be generated from distributed generation sources with one-half of these resources being located at customer facilities. The net annual incremental retail rate impact from these renewable resource acquisitions (as compared to non-renewable resources) is limited to 2%. The standard encourages the CPUC to consider earlier and timely cost recovery for utility investment in renewable resources, including the use of a forward rider mechanism. We are currently in compliance with these standards. On May 5, 2014, Colorado Electric issued an all-source generation request for approximately 42 MW of summer seasonal firm capacity in 2017, 2018 and 2019 and up to 60 MW of eligible renewable energy resources to serve its customers in southern Colorado. Colorado IPP submitted solar and wind bids in response to this request. On December 23, 2014, the independent evaluator submitted a report to the Colorado Public Utilities Commission confirming the ranking of the bids. The report's results indicate that Colorado IPP's bids were not among the highest ranked bids. However, two of the highest ranked bids provide an opportunity for Colorado Electric or our power generation segment to be partial or full owners of the facilities. At its deliberation in February 2015, the Commission determined none of the alternatives was acceptable, because of potential short-term rate impacts. The Commission discussed the possibility that Colorado Electric could more economically comply with the renewable energy standard by purchasing renewable energy credits. The purchase of renewable energy credits will be considered in a separate proceeding. After review of the Commission's decision regarding the all source solicitation (which has not yet been issued), Colorado Electric will determine whether to seek reconsideration.

- Montana. In 2005, Montana established a renewable portfolio standard that requires public utilities to obtain a percentage of their retail electricity sales from eligible renewable resources. In March 2013, Black Hills Power filed a petition with the MTPSC requesting a waiver of the renewable portfolio standards primarily due to exceeding the applicable "cost cap" included in the standards. In March 2013, the Montana Legislature adopted legislation that had the effect of excluding Black Hills Power from all renewable portfolio standard requirements under State Senate Bill 164, primarily due to the very low number of customers we have in Montana and the relatively high cost of meeting the renewable requirements.

- South Dakota. South Dakota has adopted a renewable portfolio objective that encourages, but does not mandate utilities to generate, or cause to be generated, at least 10% of their retail electricity supply from renewable energy sources by 2015.

- Wyoming. Wyoming currently has no renewable energy portfolio standard.

Absent a specific renewable energy mandate in the territories we serve, our current strategy is to prudently incorporate renewable energy into our resource supply, seeking to minimize associated rate increases for our utility customers. Mandatory portfolio standards have increased and may continue to increase the power supply costs of our Electric Utility operations. Although we will seek to recover these higher costs in rates, we can provide no assurance that we will be able to secure full recovery of the costs we pay to be in compliance with standards or objectives. We cannot at this time reasonably forecast the potential costs associated with any new renewable energy standards that have been or may be proposed at the federal or state level.

Federal Regulation

Energy Policy Act. Black Hills Corporation is a holding company whose assets consist primarily of investments in our subsidiaries, including subsidiaries that are public utilities and holding companies regulated by FERC under the Federal Power Act and PUHCA 2005.

Federal Power Act. The Federal Power Act gives FERC exclusive rate-making jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Pursuant to the Federal Power Act, all public utilities subject to FERC's jurisdiction must maintain tariffs and rate schedules on file with FERC that govern the rates, terms and conditions for the provision of FERC-jurisdictional wholesale power and transmission services. Public utilities are also subject to accounting, record-keeping and reporting requirements administered by FERC. FERC also places certain limitations on transactions between public utilities and their affiliates. Our public Electric Utility subsidiaries provide FERC-jurisdictional services subject to FERC's oversight.

Our Electric Utilities, Black Hills Colorado IPP and Black Hills Wyoming are authorized by FERC to make wholesale sales of electric capacity and energy at market-based rates under tariffs on file with FERC. As a condition of their market-based rate authority, each files Electric Quarterly Reports with FERC. Black Hills Power owns and operates FERC-jurisdictional interstate transmission facilities and provides open access transmission service under tariffs on file with FERC. Our Electric Utilities are subject to routine audit by FERC with respect to their compliance with FERC's regulations.

The Federal Power Act authorizes FERC to certify and oversee a national electric reliability organization with authority to promulgate and enforce mandatory reliability standards applicable to all users, owners and operators of the bulk-power system. FERC has certified NERC as the electric reliability organization. NERC has promulgated mandatory reliability standards and NERC, in conjunction with regional reliability organizations that operate under FERC's and NERC's authority and oversight, enforces those mandatory reliability standards.

PUHCA 2005. PUHCA 2005 gives FERC authority with respect to the books and records of a utility holding company. As a utility holding company with centralized service company subsidiaries, BHSC and Black Hills Utility Holdings, we are subject to FERC's authority under PUHCA 2005.

Environmental Matters

We are subject to numerous federal, state and local laws and regulations relating to the protection of the environment and the safety and health of personnel and the public. These laws and regulations affect a broad range of our utility activities and generally regulate: (i) the protection of air and water quality; (ii) the identification, generation, storage, handling, transportation, disposal, record-keeping, labeling, reporting of and emergency response in connection with hazardous and toxic materials and wastes, including asbestos; and (iii) the protection of plant and animal species and minimization of noise emissions.

Based on current regulations, technology and plans, the following table contains our current estimates of capital expenditures expected to be incurred over the next three years to comply with current environmental laws and regulations as described below, including regulations that cover water, air, soil and other pollutants, but excluding plant closures and the cost of new generation. The ultimate cost could be significantly different from the amounts estimated.

Environmental Expenditure Estimates	Total (in millions)
2015	$2.9
2016	3.5
2017	1.9
Total	$8.3

Water Issues

Our facilities are subject to a variety of state and federal regulations governing existing and potential water/wastewater discharges and protection of surface waters from oil pollution. Generally, such regulations are promulgated under the

Clean Water Act and govern overall water/wastewater discharges through NPDES and storm water permits. All of our facilities that are required to have such permits have those permits in place and are in compliance with discharge limitations and plan implementation requirements. The EPA proposed effluent limitation guidelines and standards on June 7, 2013. The EPA has a September 2015 deadline to issue a final regulation. These rules may have an impact on the Wyodak Plant, potentially requiring a modification to the methods of handling coal ash. Additionally, the EPA regulates surface water oil pollution through its oil pollution prevention regulations. All of our facilities subject to these regulations have compliant prevention plans in place.

Air Emissions

Our generation facilities are subject to federal, state and local laws and regulations relating to the protection of air quality. These laws and regulations cover, among other pollutants, carbon monoxide, SO_2, NO_x, mercury, particulate matter and GHG. Power generating facilities burning fossil fuels emit each of the foregoing pollutants and, therefore, are subject to substantial regulation and enforcement oversight by various governmental agencies.

Clean Air Act

Title IV of the Clean Air Act created an SO_2 allowance trading regime as part of the federal acid rain program. Each allowance gives the owner the right to emit one ton of SO_2. Certain facilities are allocated allowances based on their historical operating data. At the end of each year, each emitting unit must possess allowances sufficient to cover its emissions for the preceding year. Allowances may be traded, so affected units that expect to emit more SO_2 than their allocated allowances may purchase allowances on the open market.

Title IV applies to several of our generation facilities, including the Neil Simpson II, Neil Simpson CT, Lange CT, Wygen II, Wygen III, Pueblo Airport Generating Station, Cheyenne Prairie and Wyodak plants. Without purchasing additional allowances, we currently hold sufficient allowances to satisfy Title IV at all such plants through 2044. For future plants, we plan to secure the requisite number of allowances by reducing SO_2 emissions through the use of low sulfur fuels, installation of “back end” control technology, use of banked allowances and if necessary, the purchase of allowances on the open market. We expect to integrate the cost of obtaining the required number of allowances needed for future projects into our overall financial analysis of such new projects.

Title V of the Clean Air Act requires that all of our generating facilities obtain operating permits. All of our existing facilities have received Title V permits, with the exception of Wygen III, Pueblo Airport Generating Station and Cheyenne Prairie Generating Station. Wygen III, Pueblo Airport Generating Station and Cheyenne Prairie Generating Station are allowed to operate under their construction permit until the Title V permit is issued by the state. The Title V application for Wygen III was submitted in January 2011, with the permit expected in 2015. The Pueblo Airport Generating Station Title V application was filed in September 2012, with the permit expected in 2015. The Cheyenne Prairie Generating Station Title V application will be submitted in 2015. All applications were or will be filed in accordance with regulatory requirements.

In 2011, the EPA issued the Industrial and Commercial Boiler Regulations for Area Sources of Hazardous Air Pollutants, with updates on December 21, 2012, which impose emission limits, fuel requirements and monitoring requirements. The rule had a compliance deadline of March 21, 2014. Due to costs to retrofit these plants, we suspended operations at the Osage plant in October 2010 and suspended operations at the Ben French facility on August 31, 2012. We permanently retired Osage, Ben French and Neil Simpson I on March 21, 2014. In conjunction with the Colorado Clean Air Clean Jobs Act, the CPUC issued an order approving the closure of the W.N. Clark facility no later than December 31, 2013. The W.N. Clark facility suspended operations December 31, 2012 and was retired on December 31, 2013 in accordance with the Colorado Clean Air Clean Jobs Act.

On February 16, 2012, the EPA published in the Federal Register the National Emission Standards for Hazardous Air Pollutants from Coal and Oil Fired Electric Utility Steam Generating Units (MATS), with an effective date of April 16, 2012. This rule imposes requirements for mercury, acid gases, metals and other pollutants. Affected units have a compliance deadline of April 16, 2015, with a pathway defined to apply for a one year extension due to certain very limited circumstances. The current state air permits for Wygen II and Wygen III provide mercury emission limits and monitoring requirements with which we are in compliance. Neil Simpson II, Wygen II and Wygen III have been utilized for internal study and review of mercury emission control technology and have mercury monitors in place. Neil Simpson II, Wygen II, Wygen III and the Wyodak plant are expected to be in compliance with MATS by the compliance deadline, without incurring significant costs.

In August 2012, the EPA proposed revisions to the Electric Utility New Source Performance Standards for stationary combustion turbines. This rule is expected to be finalized in 2015 and, as proposed, will be applicable to the Pueblo Airport Generating Station, Cheyenne Prairie and eventually all the combustion turbines in our fleet. Among other things, the rule seeks to eliminate startup exemptions and clearly define overhauls for impact on the EPA's New Source Review regulations, with the intention of eventually bringing all units under the applicability of this rule. The primary impact is expected to be on our older existing units, which will eventually be required to meet tighter NO_x emission limitations.

By May 3, 2013, all of our diesel generator engines were required to comply with the EPA’s Stationary Reciprocating Internal Combustion Engine Hazardous Air Pollutant regulations. Evaluations were completed, emission control equipment was installed and emission testing confirmed compliance with those requirements.

On December 17, 2014, the EPA proposed a more stringent ozone ambient air standard. This rule is expected to be finalized in October 2015. If the lower range of the proposed standard is selected, it is anticipated the Gillette and Cheyenne, Wyoming regions would be non-attainment areas. Also, the Colorado front-range non-attainment area is expected to be expanded. Under those conditions, the states could evaluate our projects for further reductions in NO_x emissions.

In 2011, the State of Wyoming issued a letter requiring Neil Simpson II to include startup and shutdown SO_2 and NO_x emissions when evaluating compliance with permitted emission limits. This represented a significant change from requirements provided in the original 1993 air permit. Minor engineered design changes were made to improve scrubber performance during startup. Those changes enabled the unit to meet the new requirements. The unit was previously fitted with state of the art low NO_x burners that support compliance with this new requirement. Also in 2014, Neil Simpson II, Wygen II and Wygen III have converted startup fuel from diesel to natural gas to support start-up requirements and future Greenhouse Gas state compliance plans.

Regional Haze

In January 2011, the states of Wyoming and South Dakota submitted their plans to EPA Region VIII, identifying NO_x, SO_2 and particulate matter emission reductions intended to meet the Class I Areas (National Parks and Wilderness Areas) visibility improvement requirements under the EPA’s Regional Haze Program. Although none of our South Dakota or Wyoming power plants were included in those plans, we anticipate that in the next required revisions due in 2016, Neil Simpson II will be included. Ben French, Osage and Neil Simpson I were permanently retired on March 21, 2014.

In the 2010 legislative session, the State of Colorado passed House Bill 1365, the Colorado Clean Air Clean Jobs Act, a coordinated utility plan to reduce air emissions from coal fired power plants and promote the use of natural gas and other low emitting resources. One purpose of this Act was to require utilities to consider a spectrum of regulations when evaluating their emission reduction plans, with the final package ultimately comprising Colorado's Regional Haze Plan that would be submitted to EPA for approval. As required by the Act, we retired the W.N. Clark facility on December 31, 2013.

A number of our power plants have been subject to new state and EPA regulations issued in recent years. As the result of these regulations and the associated costs to retrofit many of our older generating plants, we have since permanently retired the following plants:

Plant	Company	MW	Type of Plant	Date Suspended	Actual Retirement Date	Age of Plant (in years)
Osage	Black Hills Power	34.5	Coal	October 1, 2010	March 21, 2014	64
Ben French	Black Hills Power	25.0	Coal	August 31, 2012	March 21, 2014	52
Neil Simpson I	Black Hills Power	21.8	Coal	NA	March 21, 2014	43
W.N. Clark	Colorado Electric	42.0	Coal	December 31, 2012	December 31, 2013	57
Pueblo Unit #5	Colorado Electric	9.0	Gas	December 31, 2012	December 31, 2013	71
Pueblo Unit #6	Colorado Electric	20.0	Gas	December 31, 2012	December 31. 2013	63
	Total MW	152.3				

The Wyodak Power Plant is included in EPA's January 30, 2014 Regional Haze Federal Implementation Plan, which includes significant additional NO_x controls by March 1, 2019. Our share of those costs is estimated at $20 million. The State of Wyoming and PacifiCorp filed requests for reconsideration and Administrative Stay with EPA and the

United States Court of Appeals for the 10th Circuit. On September 9, 2014, the 10th Circuit stayed EPA's NO_x requirement for Wyodak pending outcome of the appeal.

Greenhouse Gas Regulations

We utilize a diversified energy portfolio of power generation assets that include a fuel mix of coal, natural gas and wind sources, and minimal quantities of both solar and hydroelectric power. Of these generation resources, coal-fired power plants are the most significant sources of CO_2 emissions.

On June 3, 2010, the EPA promulgated the GHG Tailoring Rule, implementing regulations of GHG for permitting purposes. This rule will impact us in the event of a major modification at an existing facility or in the event we establish a new major source of GHG emissions, as defined by EPA regulations. Upon renewal of operating permits for existing permitted facilities, monitoring and reporting requirements will be implemented. Since there are no emission standards or caps currently in place, we cannot predict how this requirement will impact our existing facilities upon permit renewal. New projects or major modifications to existing projects will result in a Best Available Control Technology review that could result in more stringent emission control practices and technologies.

Wyoming passed GHG legislation in 2012 and 2013, enabling the state to implement the EPA's GHG program. Wyoming adopted and submitted a GHG regulatory program to the EPA, which the EPA approved and published in the November 22, 2013 Federal Register. As of December 23, 2013, Wyoming has full jurisdiction over the GHG permitting program which includes the transfer of the Cheyenne Prairie EPA GHG air permit, to the state of Wyoming. This eliminates the increased time, expense and considerable risk of obtaining a permit from the EPA.

The EPA was expected to finalize the first GHG emission standards for new steam electric generating units by the end of 2014. This rule, with its very low proposed CO_2 emissions standards, effectively prohibits new coal-fired power plants from being constructed until carbon capture and sequestration becomes technically and economically feasible. It also restricts simple-cycle natural gas turbines to one-third of their generating capacity based on a three-year average. The rule has not yet been finalized and may be delayed to coincide with the existing source rule finalization in June 2015.

On June 2, 2014, the EPA proposed the Clean Power Plan to cut carbon emissions from existing electric generating units. The design of the Clean Power Plan is to decrease existing coal-fired generation and increase the utilization of existing gas generation, increase renewable energy and demand side management. This rule, expected to be final in June 2015, could have a significant impact on our coal and natural gas generating fleet. The rule calls for states to develop plans to meet their assigned emission rate targets by 2030. While we cannot predict the terms of the regulation, any federally mandated GHG reductions or limits on CO_2 emissions at our existing plants could have a material impact on our customer rates, financial position, results of operations and/or cash flows.

In 2014, we reported 2013 GHG emissions from our Power Generation and Gas Utilities in order to comply with the EPA's GHG Annual Inventory regulation, issued in 2009. We continue to report annual GHG emissions as required by the EPA. In addition to federal legislative activity, GHG regulations have been proposed in various states and alleged climate change issues are the subject of a number of lawsuits, the outcome of which could impact the utility industry. We will continue to review GHG impacts as legislation or regulation develops and litigation is resolved.

New or more stringent regulations or other energy efficiency requirements could require us to incur significant additional costs relating to, among other things, the installation of additional emission control equipment, the acceleration of capital expenditures, the purchase of additional emissions allowances or offsets, the acquisition or development of additional energy supply from renewable resources and the closure of certain generating facilities. To the extent our regulated fossil-fuel generating plants are included in rate base, we will attempt to recover costs associated with complying with emission standards or other requirements. We will also attempt to recover the emission compliance costs of our non-regulated fossil-fuel generating plants from utility customers and other purchasers of the power generated by our non-regulated power plants, including utility affiliates. Any unrecovered costs could have a material impact on our results of operations, financial position or cash flows. In addition, future changes in environmental regulations governing air emissions could render some of our power generating units more expensive or uneconomical to operate and maintain.

Solid Waste Disposal

Various materials used at our facilities are subject to disposal regulations. Under state permits, we dispose of all solid wastes collected as a result of burning coal at our power plants in approved solid waste disposal sites. Ash and waste from flue gas and sulfur removal from the Ben French, Wyodak, Neil Simpson I, Neil Simpson II, Wygen II and Wygen III plants are deposited in mined areas at the WRDC coal mine. These disposal areas are currently located below some shallow water aquifers in the mine. In 2009, the State of Wyoming confirmed its past approval of this practice but may re-evaluate and limit ash disposal to mined areas that are above groundwater aquifers. This change would increase disposal costs, which cannot be quantified until the exact requirements are known. None of the solid waste from the burning of coal is currently classified as hazardous material, but the waste does contain minute traces of metals that could be perceived as polluting if such metals leached into underground water. We conducted investigations which concluded that the wastes are relatively insoluble and will not measurably affect the post-mining ground water quality.

We permanently retired the Osage power plant on March 21, 2014. This plant had an on-site ash impoundment that was near capacity. An application to close the impoundment was approved on April 13, 2012. Site closure work was completed and the state issued an approval of closure activities on October 21, 2014. Post-closure monitoring activities will continue for 30 years. In September 2013, Osage also received a permit to close the small industrial rubble landfill. Site work has been completed and the state issued an approval of closure activities on October 21, 2014. Post closure monitoring will continue for 30 years. As of August 31, 2012, we suspended operations at Ben French and the plant was permanently retired on March 21, 2014. The Ben French temporary ash holding area was closed in accordance with state guidelines, with the state issuing a closure certification on March 14, 2014.

Our W.N. Clark plant, which suspended operations on December 31, 2012 and was retired on December 31, 2013, sent coal ash to a permitted, privately-owned landfill. While we do not believe that any substances from our solid waste disposal activities will pollute underground water, we can provide no assurance that pollution will not occur over time. In this event, we could incur material costs to mitigate any resulting damages.

For our Pueblo Airport Generation Station in Pueblo, Colorado, we posted a bond with the State of Colorado to cover the costs of remediation for a waste water containment pond permitted to provide wastewater storage and processing for this zero discharge facility.

Agreements are in place that requires PacifiCorp and MEAN to be responsible for any costs related to the solid waste from their ownership interest in the Wyodak plant and Wygen I plant, respectively. As operator of Wygen III, Black Hills Power has a similar agreement in place for any such costs related to solid waste from Wygen III. Under their separate but related operating agreement, Black Hills Power, MDU and the City of Gillette each share the costs for solid waste from Wygen III according to their respective ownership interests.

Additional unexpected material costs could also result in the future if any regulatory agency determines that solid waste from the burning of coal contains a hazardous material that requires special treatment, including previously disposed solid waste. In that event, the regulatory authority could hold entities that dispose of such waste responsible for remedial treatment. On December 19, 2014, the EPA Administrator signed coal ash regulations designating coal ash as a solid waste. These regulations are not applicable to our operations as all our coal ash is used as mine backfill. However, we are reviewing the requirements as it is expected the U.S. Office of Surface Mining will eventually develop their own regulations, potentially using these requirements as a guide.

Manufactured Gas Processing

Some federal and state laws authorize the EPA and other agencies to issue orders compelling potentially responsible parties to clean up sites that are determined to present an actual or potential threat to human health or the environment.

As a result of the Aquila Transaction, we acquired whole and partial liabilities for several former manufactured gas processing sites in Nebraska and Iowa which were previously used to convert coal to natural gas. The acquisition provided for a $1.0 million insurance recovery, now valued at approximately $1.3 million, which will be used to help offset remediation costs. The remediation cost estimate could change materially due to results of further investigations, actions of environmental agencies or the financial viability of other responsible parties.

In March 2011, Nebraska Gas executed an Allocation, Indemnification and Access Agreement with the successor to the former operator of the Nebraska MGPs. Under this agreement, Nebraska Gas received $1.9 million from the successor to the operator for Nebraska Gas to remediate two sites in Nebraska (Blair and Plattsmouth). The successor is responsible for remediation activity at the two remaining sites in Nebraska (Columbus and Norfolk). Subsequent to this transaction, Nebraska Gas enrolled Blair and Plattsmouth in Nebraska's Voluntary Cleanup Program. Site remediation was completed in September 2012. Both Nebraska sites will be required to monitor groundwater quality for a minimum two-year period ending in 2015.

As of December 31, 2014, we estimate a range of approximately $2.7 million to $6.3 million to remediate the MGP site in Council Bluffs, Iowa, of which we could be responsible for up to 25% of the costs. In 2014, we began the process of evaluating legal and corporate successorship avenues for cost recovery from other potential responsible parties. At this time no parties have been formally named nor have we determined the degree to which they are responsible. There are currently no regulatory requirements or deadlines for cleanup.

As part of the Aquila Transaction, we also acquired the former Lawrence, Kansas MGP site which was partially addressed through a removal action conducted in the early 2000s under the supervision of the Kansas Department of Health and Environment. An existing warehouse that is the last remnant of the former MGP site will be removed in 2015 to enable environmental characterization of the area beneath the building. We estimate remaining site activities will not exceed $150,000.

Prior to Black Hills Corporation's ownership, Aquila received rate orders that approved recovery of environmental cleanup costs in certain jurisdictions. We anticipate recovery of current and future remediation costs would be allowed. Additionally, we may pursue recovery or agreements with other potentially responsible parties when and where permitted.

Non-regulated Energy Group

Our Non-regulated Energy Group, which operates through various subsidiaries, produces and sells electric capacity and energy through a portfolio of generating plants, produces and sells coal from our mine located in the Powder River Basin in Wyoming and acquires, explores for, develops and produces natural gas and crude oil primarily in the Rocky Mountain region. The Non-regulated Energy Group consists of three business segments for reporting purposes:

- Power Generation
- Coal Mining
- Oil and Gas

Power Generation Segment

Our Power Generation segment, which operates through Black Hills Electric Generation and its subsidiaries, acquires, develops and operates our non-regulated power plants. As of December 31, 2014, we held varying interests in independent power plants operating in Wyoming and Colorado with a total net ownership of approximately 269 MW.

Portfolio Management

We produce electric power from our generating plants and sell the electric capacity and energy, primarily to affiliates under a combination of mid- to long-term contracts, which mitigates the impact of a potential downturn in future power prices. We currently sell a substantial majority of our non-regulated generating capacity under contracts having terms greater than one year.

As of December 31, 2014, the power plant ownership interests held by our Power Generation segment included:

Power Plants	Fuel Type	Location	Ownership Interest	Owned Capacity (MW)	In Service Date
Wygen I	Coal	Gillette, Wyoming	76.5%	68.9	2003
Pueblo Airport Generation [1]	Gas	Pueblo, Colorado	100.0%	200.0	2012
				268.9	

(1) Black Hills Colorado IPP owns and operates this facility. This facility provides capacity and energy to Colorado Electric under a 20-year PPA with Colorado Electric. This PPA is accounted for as a capital lease on the accompanying Consolidated Financial Statements.

Black Hills Wyoming - Wygen I. The Wygen I generation facility is a mine-mouth, coal-fired power plant with a total capacity of 90 MW located at our Gillette, Wyoming energy complex. We own 76.5% of the plant and MEAN owns the remaining 23.5%. We sell 60 MW of unit-contingent capacity and energy from this plant to Cheyenne Light under a PPA that expires on December 31, 2022. The PPA includes an option for Cheyenne Light to purchase Black Hills Wyoming's ownership interest in the Wygen I facility through 2019. The purchase price in the contract related to the option is $2.6 million per megawatt adjusted for capital additions and reduced by depreciation over 35 years starting January 1, 2009 (approximately $5 million per year). The net book value of Wygen I at December 31, 2014 was $79 million and if Cheyenne Light had exercised the purchase option at year-end 2014, the estimated purchase price would have been approximately $154 million. We expect Cheyenne Light to exercise its option to purchase sometime during the next several years, at which time we will file for approval with the WPSC. We sell excess power from our generating capacity into the wholesale power markets when it is available and economical.

Black Hills Colorado IPP - Pueblo Airport Generation. The Pueblo Airport Generation Station consists of two 100 MW combined-cycle gas-fired power generation plants located at a site shared with Colorado Electric. The plants commenced operation on January 1, 2012 and the assets are accounted for as a capital lease under a 20-year PPA with Colorado Electric. Under the PPA with Colorado Electric, any excess capacity and energy shall be for the benefit of Colorado Electric.

The following table summarizes MWh for our Power Generation segment:

Quantities Sold, Generated and Purchased (MWh) [1]	2014	2013	2012
Sold			
Black Hills Colorado IPP	1,178,464	1,008,482	762,950
Black Hills Wyoming [2]	581,696	556,307	541,687
Total Sold	1,760,160	1,564,789	1,304,637
Generated			
Black Hills Colorado IPP	1,178,464	1,008,482	762,950
Black Hills Wyoming	543,796	556,106	538,945
Total Generated	1,722,260	1,564,588	1,301,895
Purchased			
Black Hills Colorado IPP	—	—	—
Black Hills Wyoming [2]	38,237	5,481	8,011
Total Purchased	38,237	5,481	8,011

(1) Company use and losses are not included in the quantities sold, generated and purchased.

(2) Under the 20-year economy energy PPA with the City of Gillette, effective September 2014, Black Hills Wyoming purchases energy on behalf of the City of Gillette.

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Operating Agreements. Our Power Generation segment has the following material operating agreements:

- Economy Energy PPA and other ancillary agreements -

Black Hills Wyoming sold its CTII 40 MW natural gas-fired generating unit to the City of Gillette, Wyoming on September 3, 2014. Under the terms of the sale, Black Hills Wyoming entered into ancillary agreements to operate CTII, provide use of shared facilities including a ground lease and dispatch generation services. In addition, the agreement includes a 20-year economy energy PPA that contains a sharing arrangement in which the parties share the savings of wholesale power purchases made when market power prices are less than the cost of operating the generating unit.

- Shared Services Agreements -

Black Hills Power, Cheyenne Light and Black Hills Wyoming are parties to a shared facilities agreement, whereby each entity charges for the use of assets by the affiliate entity.

Black Hills Colorado IPP and Colorado Electric are parties to a facility fee agreement, whereby Colorado Electric charges Black Hills Colorado IPP for the use of Colorado Electric assets.

Colorado IPP and Black Hills Wyoming receive certain staffing and management services from BHSC.

- Jointly Owned Facilities -

Black Hills Wyoming and MEAN are parties to a shared joint ownership agreement, whereby Black Hills Wyoming charges MEAN for administrative services, plant operations and maintenance on their share of the Wygen I generating facility over the life of the plant.

Competition. The independent power industry consists of many strong and capable competitors, some of which may have more extensive operating experience or greater financial resources than we possess.

With respect to the merchant power sector, FERC has taken steps to increase access to the national transmission grid by utility and non-utility purchasers and sellers of electricity and foster competition within the wholesale electricity markets. Our Power Generation business could face greater competition if utilities are permitted to robustly invest in power generation assets. Conversely, state regulatory rules requiring utilities to competitively bid generation resources may provide opportunity for independent power producers in some regions.

The Energy Policy Act of 1992. The passage of the Energy Policy Act of 1992 encouraged independent power production by providing certain exemptions from regulation for EWGs. EWGs are exclusively in the business of owning or operating, or both owning and operating, eligible power facilities and selling electric energy at wholesale. EWGs are subject to FERC regulation, including rate regulation. We own two EWGs: Wygen I and 200 MW (two 100 MW combined-cycle gas-fired units) at the Pueblo Airport Generating Station. Our EWGs were granted market-based rate authority, which allows FERC to waive certain accounting, record-keeping and reporting requirements imposed on public utilities with cost-based rates.

Environmental Regulation. Many of the environmental laws and regulations applicable to our regulated Electric Utilities also apply to our Power Generation operations. See the discussion above under the “Environmental” and “Regulation” captions for the Utilities Group for additional information on certain laws and regulations.

Clean Air Act. The Clean Air Act impacts our Power Generation business in a manner similar to the impact disclosed for our Electric Utilities. Our Wygen I and Pueblo Airport Generating facilities are subject to Titles IV and V of the Clean Air Act and have the required permits in place or have applications submitted in accordance with regulatory time lines. As a result of SO_2 allowances credited to us from the installation of sulfur removal equipment at our jointly owned Wyodak plant, we hold sufficient allowances for our Wygen I plant through 2044, without purchasing additional allowances. The EPA’s MACT rule described in the Utilities Group section will apply to Wygen I.

Clean Water Act. The Clean Water Act impacts our Power Generation business in a manner similar to the impact described above for our Electric Utilities. Each of our facilities that is required to have NPDES permits have those permits and are in compliance with discharge limitations. The EPA also regulates surface water oil pollution prevention through its oil pollution prevention regulations. Each of our facilities regulated under this program have the requisite pollution prevention plans in place.

Solid Waste Disposal. We dispose of all Wygen I coal ash and scrubber wastes in mined areas at our WRDC coal mine under the terms and conditions of a state permit. The factors discussed under this caption for the Utilities Group also impact our Power Generation segment in a similar manner.

Greenhouse Gas Regulations. The EPA's GHG Tailoring Rule described in the Utilities Group section will apply to the Wygen I and the Pueblo Airport Generating units upon a major modification, upon operating permit renewal or in the case of Pueblo Airport Generating Station, upon initial issuance of the Title V operating permit.

Coal Mining Segment

Our Coal Mining segment operates through our WRDC subsidiary. We surface mine, process and sell primarily low-sulfur sub-bituminous coal at our coal mine near Gillette, Wyoming. The WRDC coal mine, which we acquired in 1956 from Homestake Gold Mining Company, is located in the Powder River Basin. The Powder River Basin contains one of the largest coal reserves in the United States. We produced approximately 4.3 million tons of coal in 2014.

During our surface mining operations, we strip and store the topsoil. We then remove the overburden (earth and rock covering the coal) with heavy equipment. Removal of the overburden sometimes requires drilling and blasting. Once the coal is exposed, we drill, fracture and systematically remove it, using front-end loaders and conveyors to transport the coal to the mine-mouth generating facilities. We reclaim disturbed areas as part of our normal mining activities by back-filling the pit with overburden removed during the mining process. Once we have replaced the overburden and topsoil, we re-establish vegetation and plant life in accordance with our approved Post Mining Topography plan.

In a basin characterized by thick coal seams, our overburden ratio, a comparison of the cubic yards of dirt removed to a ton of coal uncovered, had in recent years trended upwards. The overburden ratio decreased in the second half of 2012 when we relocated mining operations to an area of the mine with lower overburden. The overburden ratio was reduced approximately 60% during 2013. In 2014, the overburden ratio increased as we are entering mining areas with higher overburden, resulting in an increased stripping ratio of 1.08. We expect our stripping ratio to increase to approximately 1.5 in 2015 as we mine back into areas with higher overburden.

Mining rights to the coal are based on four federal leases and one state lease. The federal leases expire between September 30, 2015 to March 31, 2021 and the state lease expires on August 1, 2023. The duration of the leases varies; however, the lease terms generally are extended to the exhaustion of economically recoverable reserves, as long as active mining continues. We pay federal and state royalties of 12.5% and 9.0%, respectively, of the selling price of all coal. As of December 31, 2014, we estimated our recoverable coal reserves to be approximately 208 million tons, based on a life-of-mine engineering study utilizing currently available drilling data and geological information prepared by internal engineering studies. The recoverable coal reserve life is equal to approximately 48 years at the current expected production levels. Our recoverable coal reserve estimates are periodically updated to reflect past coal production and other geological and mining data. Changes in mining methods or the utilization of new technologies may increase or decrease the recovery basis for a coal seam. Our recoverable coal reserves include reserves that can be economically and legally extracted at the time of their determination. We use various assumptions in preparing our estimate of recoverable coal reserves. See Risk Factors under Coal Mining for further details.

Substantially all of our coal production is currently sold under mid-term and long-term contracts to:

- Black Hills Power for use at its Neil Simpson II plant;
- Cheyenne Light for use at its Wygen II plant;

- the 362 MW Wyodak power plant owned 80% by PacifiCorp and 20% by Black Hills Power. PacifiCorp is obligated to purchase a minimum of 1.5 million tons of coal each year of the contract term, subject to adjustments for planned outages. This contract expires at the end of December 2022;

- the 110 MW Wygen III power plant owned 52% by Black Hills Power, 25% by MDU and 23% by the City of Gillette to which we sell approximately 600,000 tons of coal each year. This contract expires June 1, 2060;

- the 90 MW Wygen I power plant owned 76.5% by Black Hills Wyoming and 23.5% by MEAN to which we sell approximately 500,000 tons of coal each year. This contract expires June 30, 2038; and

- certain regional industrial customers served by truck to which we sell a total of approximately 150,000 tons of coal each year. These contracts are short-term and have terms of one to three years.

Our Coal Mining segment sells coal to Black Hills Power and Cheyenne Light for all of their requirements under cost-based agreements that regulate earnings from these affiliate coal sales to a specified return on our coal mine’s cost-depreciated investment base. The return calculated annually is 400 basis points above A-rated utility bonds applied to our coal mining investment base. Black Hills Power made a commitment to the SDPUC, the WPSC and the City of Gillette that coal for Black Hills Power’s operating plants would be furnished and priced as provided by that agreement for the life of the Neil Simpson II plant and through June 1, 2060, for Wygen III. The agreement with Cheyenne Light provides coal for the life of the Wygen II plant.

The price of unprocessed coal sold to PacifiCorp for the Wyodak plant is determined by the coal supply agreement described above. The agreement includes a price adjustment in 2014, which has been implemented, and an additional price adjustment in 2019. The price adjustments essentially allow us to retain the full economic advantage of the mine's location adjacent to the plant. The price adjustments will be based on the market price of coal plus considerations for the avoided costs of rail transportation and a coal unloading facility which PacifiCorp would have to incur if it purchased coal from another mine. In addition, the agreement also provides for the monthly escalation of coal price based on an escalation factor.

WRDC supplies coal to Black Hills Wyoming for the Wygen I generating facility for requirements under an agreement using a base price that includes price escalators and quality adjustments through June 30, 2038 and includes actual cost per ton plus a margin equal to the yield for Moody’s A-Rated 10-Year Corporate Bond Index plus 400 basis points with the base price being adjusted on a 5-year interval. The agreement stipulates that WRDC will supply coal to the 90 MW Wygen I plant through June 30, 2038.

Competition. Our primary strategy is to sell the majority of our coal production to on-site, mine-mouth generation facilities under long-term supply contracts. Historically, off-site sales have been to consumers within a close proximity to the mine. Rail transport market opportunities for WRDC coal are limited due to the lower heating value (Btu) of the coal, combined with the fact that the WRDC coal mine is served by only one railroad, resulting in less competitive transportation rates. Management continues to explore the limited market opportunities for our product through truck transport.

Additionally, coal competes with other energy sources, such as natural gas, wind, solar and hydropower. Costs and other factors relating to these alternative fuels, such as safety, environmental considerations and availability affect the overall demand for coal as a fuel.

Environmental Regulation. The construction and operation of coal mines are subject to environmental protection and land use regulation in the United States. These laws and regulations often require a lengthy and complex process of obtaining licenses, permits and approvals from federal, state and local agencies. Many of the environmental issues and regulations discussed under the Utilities Group also apply to our Coal Mining segment.

Operations at WRDC must regularly address issues arising due to the proximity of the mine disturbance boundary to the City of Gillette and to residential and industrial development. Homeowner complaints and challenges to the permits may occur as mining operations move closer to residential development areas. Specific concerns could include damage to wells, fugitive dust emissions and vibration and nitrous oxide fumes from blasting. To mitigate these concerns, WRDC is actively pursuing the establishment of buffer zones through land purchases and long-term surface leases.

Ash is the inorganic residue remaining after the combustion of coal. Ash from our Wyoming power plants, as well as PacifiCorp’s Wyodak power plant, is disposed of in the mine and is utilized for backfill to meet permitted post-mining contour requirements. On December 19, 2014, the EPA signed national disposal regulations regulating coal ash as a solid waste. While these regulations do not address mine backfill, it is widely expected that the U.S. Office of Surface Mining will collaborate with the EPA to address mine backfill in the near future. These regulations may increase the cost of ash disposal for the power plants and/or increase backfill costs for the coal mine.

Mine Reclamation. Reclamation is required during production and after mining has been completed. Under applicable law, we must submit applications to, and receive approval from, the WDEQ for any mining and reclamation plan that provides for orderly mining, reclamation and restoration of the WRDC mine. We have approved mining permits and are in compliance with other permitting programs administered by various regulatory agencies. The WRDC coal mine is permitted to operate under a five year mining permit issued by the State of Wyoming. The current permit expires in 2016. Based on extensive reclamation studies, we have accrued approximately $19 million for reclamation costs as of December 31, 2014. Mining regulatory requirements continue to increase, which impose additional cost on the mining process.

Oil and Gas Segment

Our Oil and Gas segment, which conducts business through BHEP and its subsidiaries, acquires, explores for, develops and produces natural gas and crude oil in the United States primarily in the Rocky Mountain region.

As of December 31, 2014, the principal assets of our Oil and Gas segment included: (i) operating interests in crude oil and natural gas properties, including properties in the San Juan Basin (with holdings primarily on the tribal lands of the Jicarilla Apache Nation in New Mexico and Southern Ute Nation in Colorado), the Powder River Basin (Wyoming) and the Piceance Basin (Colorado); (ii) non-operated interests in crude oil and natural gas properties including wells located in the Williston (Bakken Shale in North Dakota), Wind River (Wyoming), Bear Paw Uplift (Montana), Arkoma (Oklahoma), Anadarko (Texas and Kansas) and Sacramento (California) basins; and (iii) a 44.7% ownership interest in the Newcastle gas processing plant and associated gathering system located in Weston County, Wyoming. The plant, operated by Western Gas Partners, LP, is adjacent to our producing properties in that area and BHEP's production accounts for more than 55% of the facility's throughput. We also own natural gas gathering, compression and treating facilities, and water collection and delivery systems serving the operated San Juan and Piceance Basin properties and working interests in similar facilities serving our non-operated Montana and Wyoming properties.

At December 31, 2014, we had total reserves of approximately 101 Bcfe, of which natural gas comprised 65%, crude oil comprised 25% and NGLs comprised 10%. The majority of our reserves are located in select crude oil and natural gas producing basins in the Rocky Mountain region. Approximately 24% of our reserves are located in the San Juan Basin of northwestern New Mexico, primarily in the East Blanco Field of Rio Arriba County; 31% are located in the Powder River Basin of Wyoming, primarily in the Finn-Shurley Field of Weston and Niobrara counties; and 33% are located in the Piceance Basin of western Colorado, primarily in Mesa county.

Effective July 1, 2012, we sold approximately 85% of our Bakken and Three Forks shale assets in the Williston Basin in North Dakota, including approximately 73 gross wells and 28,000 net leasehold acres.

Summary Oil and Gas Reserve Data

The summary information presented for our estimated proved developed and undeveloped crude oil, natural gas, and NGL reserves and the 10% discounted present value of estimated future net revenues is based on reports prepared by Cawley Gillespie & Associates, an independent consulting and engineering firm located in Fort Worth, Texas. Reserves were determined consistent with SEC requirements using a 12-month average product price calculated using the first-day-of-the-month price for each of the 12 months in the reporting period held constant for the life of the properties. Estimates of economically recoverable reserves and future net revenues are based on a number of variables, which may differ from actual results. Reserves for crude oil, natural gas, and NGLs are reported separately and then combined for a total MMcfe (where oil and NGLs in Mbbl are converted to an MMcfe basis by multiplying Mbbl by six).

The SEC definition of "reliable technology" allows the use of any reliable technology to establish reserve volumes in addition to those established by production and flow test data. This definition allows, but does not require us, to book PUD locations that are more than one location away from a producing well. We elected to only include PUDs which are one location away from a producing well in our volume reserve estimate. Companies are allowed, but not required, to disclose probable and possible reserves. We have elected not to report these additional reserve categories. Additional information on our oil and gas reserves, related financial data and the SEC requirements can be found in Note 20 to the Consolidated Financial Statements in this Annual Report on Form 10-K.

We maintain adequate and effective internal controls over the reserve estimation process as well as the underlying data upon which reserve estimates are based. The primary inputs to the reserve estimation process are comprised of technical information, financial data, ownership interest and production data. All field and reservoir technical information, which is updated annually, is assessed for validity when the reservoir engineers hold technical meetings with geoscientists, operations and land personnel to discuss field performance and to validate future development plans. Our internal engineers and our independent reserve engineering firm, CG&A, work independently and concurrently to develop reserve volume estimates. Current revenue and expense information is obtained from our accounting records, which are subject to external quarterly reviews, annual audits and internal controls over financial reporting. All current financial data such as commodity prices, lease operating expenses, production taxes and field commodity price differentials are updated in the reserve database and then analyzed to ensure that they have been entered accurately and that all updates are complete. Our current ownership in mineral interests and well production data are also subject to the aforementioned internal controls over financial reporting and they are incorporated in the reserve database and verified to ensure their accuracy and completeness. Once the reserve database has been entirely updated with current information and all relevant technical support materials have been assembled, CG&A meets with our technical personnel to review field performance and future development plans to further verify their validity. Following these reviews the reserve database, including updated cost, price and ownership data, is furnished to CG&A so they can prepare their independent reserve estimates and final report. Access to our reserve database is restricted to specific members of the engineering department.

CG&A is a Texas Registered Engineering Firm. Our primary contact at CG&A is Mr. Zane Meekins. Mr. Meekins has been practicing consulting petroleum engineering since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas and has over 26 years of practical experience in petroleum engineering and over 24 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1987 with a Bachelor of Science in Petroleum Engineering. Mr. Meekins meets or exceeds the education, training and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

BHEP’s Manager of Planning and Analysis is the technical person primarily responsible for overseeing our third party reserve estimates. He has over 34 years of exploration and production industry experience as a geologist and financial analyst. He has over 24 years of experience working closely with internal and third party qualified reserve estimators in major and mid-sized oil and gas companies. He holds a Bachelor of Science degree in Geology and a Master’s in Business Administration.

As of December 31, 2014, we began to separate the NGL production and reserves from the prior years reported wet natural gas reserves and production. NGL production and reserves are processed volumes received by taking the wellhead gas to a gas plant where the various components are extracted into a dry natural gas stream and a natural gas liquids stream. NGL volumes reported are in barrels and are the weighted volumes of the various liquids components; ethane (if recovered), propane, iso butane, normal butane, and natural gasoline. Presently, ethane is not being recovered at any of the facilities that process our natural gas production.

Minor differences in amounts may result in the following tables relating to oil and gas reserves due to rounding.

The following tables set forth summary information concerning our estimated proved developed and undeveloped reserves, by basin, as of December 31, 2014, 2013 and 2012:

Proved Reserves	December 31, 2014					
	Total	Piceance	San Juan	Williston	Powder River	Other
Developed Producing -						
Natural Gas (MMcf)	51,718	16,802	24,349	650	4,231	5,679
Oil (Mbbl)	3,779	54	11	494	3,191	28
NGLs (Mbbl)	1,472	344	—	25	1,007	96
Total Developed Producing (MMcfe)	83,222	19,190	24,415	3,764	29,419	6,423
Developed Non-Producing -						
Natural Gas (MMcf)	5,709	4,920	183	—	—	630
Oil (Mbbl)	—	—	—	—	—	—
NGLs (Mbbl)	58	58	—	—	—	—
Total Developed Non-Producing (MMcfe)	6,056	5,268	183	—	—	630
Undeveloped -						
Natural Gas (MMcf)	8,013	7,833	—	180	—	—
Oil (Mbbl)	496	6	—	159	331	—
NGLs (Mbbl)	191	191	—	—	—	—
Total Undeveloped (MMcfe)	12,134	9,015	—	1,134	1,986	—
Total MMcfe	101,416	33,465	24,596	4,898	31,405	7,053

Proved Reserves [(a)]	December 31, 2013					
	Total	Piceance	San Juan	Williston	Powder River	Other
Developed Producing -						
Natural Gas (MMcf)	55,090	14,976	26,083	723	7,301	6,007
Oil (Mbbl)	3,661	29	6	479	3,115	32
Total Developed Producing (MMcfe)	77,053	15,150	26,119	3,597	25,988	6,199
Developed Non-Producing -						
Natural Gas (MMcf)	5,134	4,302	183	—	—	649
Oil (Mbbl)	28	28	—	—	—	—
Total Developed Non-Producing (MMcfe)	5,302	4,470	183	—	—	649
Undeveloped -						
Natural Gas (MMcf)	2,966	1,986	635	345	—	—
Oil (Mbbl)	232	14	—	218	—	—
Total Undeveloped (MMcfe)	4,358	2,070	635	1,653	—	—
Total MMcfe	86,713	21,690	26,937	5,250	25,988	6,848

Proved Reserves [a]	December 31, 2012					
	Total	Piceance	San Juan	Williston	Powder River	Other
Developed Producing -						
Natural Gas (MMcf)	54,086	11,813	28,159	820	7,555	5,739
Oil (Mbbl)	3,851	7	12	489	3,321	22
Total Developed Producing (MMcfe)	77,192	11,855	28,231	3,754	27,481	5,871
Developed Non-Producing -						
Natural Gas (MMcf)	1,622	335	457	—	186	644
Oil (Mbbl)	78	—	—	—	78	—
Total Developed Non-Producing (MMcfe)	2,090	335	457	—	654	644
Undeveloped -						
Natural Gas (MMcf)	279	—	—	279	—	—
Oil (Mbbl)	187	—	—	187	—	—
Total Undeveloped (MMcfe)	1,401	—	—	1,401	—	—
Total MMcfe	80,683	12,190	28,688	5,155	28,135	6,515

(a) Proved reserves presented for 2013 and 2012 do not include NGL's.

Change in Proved Reserves

The following tables summarize the change in quantities of proved developed and undeveloped reserves by basin, estimated using SEC-defined product prices, as of December 31, 2014, 2013 and 2012:

Crude Oil	December 31, 2014					
(in Mbbl)	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	3,921	70	7	697	3,115	32
Production	(337)	(12)	(1)	(132)	(189)	(3)
Additions - acquisitions (sales)	(40)	—	—	(40)	—	—
Additions - extensions and discoveries	733	51	—	72	610	—
Revisions to previous estimates	(1)	(50)	6	55	(14)	2
Balance at end of year	4,276	59	12	652	3,522	31

Natural Gas	December 31, 2014					
(in MMcf)	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	63,190	21,265	26,903	1,067	7,299	6,656
Production	(7,156)	(2,273)	(3,589)	(180)	(370)	(744)
Additions - acquisitions (sales)	(61)	—	—	(61)	—	—
Additions - extensions and discoveries	11,003	10,911	—	83	1	8
Revisions to previous estimates	(1,536)	(338)	1,219	(67)	(2,714)	364
Balance at end of year	65,440	29,565	24,533	842	4,216	6,284

Natural Gas Liquids	December 31, 2014					
(in Mbbl)	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	—	—	—	—	—	—
Production	(135)	(56)	—	(5)	(65)	(9)
Additions - acquisitions (sales)	—	—	—	—	—	—
Additions - extensions and discoveries	182	178	—	4	—	—
Revisions to previous estimates	1,673	470	—	26	1,072	105
Balance at end of year	1,720	592	—	25	1,007	96

	December 31, 2014					
Total MMcfe	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	86,713	21,677	26,938	5,242	26,001	6,855
Production	(9,984)	(2,681)	(3,595)	(997)	(1,895)	(816)
Additions - acquisitions (sales)	(299)	—	—	(299)	—	—
Additions - extensions and discoveries	16,495	12,286	—	536	3,664	9
Revisions to previous estimates (b)	8,491	2,183	1,253	416	3,634	1,005
Balance at end of year	101,416	33,465	24,596	4,898	31,404	7,053

Crude Oil	December 31, 2013					
(in Mbbl)	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	4,116	7	12	676	3,399	22
Production	(336)	(2)	(1)	(126)	(206)	(1)
Additions - acquisitions (sales)	(30)	—	—	(30)	—	—
Additions - extensions and discoveries	379	68	—	283	20	8
Revisions to previous estimates	(208)	(3)	(5)	(106)	(98)	3
Balance at end of year	3,921	70	7	697	3,115	32

Natural Gas	December 31, 2013					
(in MMcf)	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	55,985	12,152	28,618	1,103	7,735	6,377
Production	(6,984)	(1,345)	(3,837)	(164)	(366)	(1,272)
Additions - acquisitions (sales)	(46)	—	—	(46)	—	—
Additions - extensions and discoveries	10,456	9,830	—	425	96	105
Revisions to previous estimates	3,779	628	2,122	(251)	(166)	1,446
Balance at end of year	63,190	21,265	26,903	1,067	7,299	6,656

Total MMcfe [a]	December 31, 2013 Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	80,683	12,190	28,688	5,155	28,135	6,515
Production	(9,000)	(1,357)	(3,843)	(920)	(1,602)	(1,278)
Additions - acquisitions (sales)	(226)	—	—	(226)	—	—
Additions - extensions and discoveries	12,730	10,238	—	2,123	216	153
Revisions to previous estimates [b]	2,526	606	2,093	(890)	(748)	1,465
Balance at end of year	86,713	21,677	26,938	5,242	26,001	6,855

(a) Production for reserve calculations does not include volumes for NGLs.

(b) Revisions to previous estimates for 2013 were primarily due to commodity price changes.

Crude Oil (in Mbbl)	December 31, 2012 Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	6,223	—	12	2,641	3,549	21
Production	(560)	—	(1)	(338)	(218)	(3)
Additions - acquisitions (sales)	(2,025)	—	—	(1,983)	(42)	—
Additions - extensions and discoveries	449	5	—	401	43	—
Revisions to previous estimates	29	2	1	(45)	67	4
Balance at end of year	4,116	7	12	676	3,399	22

Natural Gas (in MMcf)	December 31, 2012 Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	95,904	28,363	44,595	4,056	8,926	9,964
Production	(8,686)	(1,718)	(4,926)	(427)	(446)	(1,169)
Additions - acquisitions (sales)	(3,070)	—	—	(3,070)	—	—
Additions - extensions and discoveries	2,898	1,884	235	648	85	46
Revisions to previous estimates	(31,061)	(16,377)	(11,286)	(104)	(830)	(2,464)
Balance at end of year	55,985	12,152	28,618	1,103	7,735	6,377

Total MMcfe [a]	December 31, 2012 Total	Piceance	San Juan	Williston [b]	Powder River	Other
Balance at beginning of year	133,242	28,363	44,667	19,902	30,220	10,090
Production	(12,046)	(1,718)	(4,932)	(2,455)	(1,754)	(1,187)
Additions - acquisitions (sales)	(15,220)	—	—	(14,968)	(252)	—
Additions - extensions and discoveries	5,592	1,914	235	3,054	343	46
Revisions to previous estimates [c]	(30,885)	(16,369)	(11,282)	(378)	(422)	(2,434)
Balance at end of year	80,683	12,190	28,688	5,155	28,135	6,515

(a) Production for reserve calculations does not include volumes for NGLs.

(b) Reflects sale of the majority of our Williston Basin assets in 2012.

(c) Revisions to previous estimates for 2012 were primarily due to commodity price changes. Included in the total revisions is (27,051) MMcfe due to lower commodity prices, (2,422) MMcfe for dropped PUD locations due to the

SEC requirement that PUD locations must be developed within five years or must be removed from PUD reserves, which was partially offset by positive performance revisions of (1,565) MMcfe in various basins.

Production Volumes

		Year ended December 31, 2014			
Location (Basin)	Field	Oil (in Bbl)	Natural Gas (Mcfe)	NGLs (in Bbl)	Total (Mcfe)
San Juan	East Blanco	1,793	2,389,973	—	2,400,731
San Juan	All Others	—	1,191,239	—	1,191,239
Piceance	Piceance	3,393	2,219,224	56,244	2,577,043
Powder River	Finn Shurley	153,632	263,491	60,142	1,546,136
Powder River	All others	49,602	—	—	297,612
Williston	Bakken	115,980	116,170	4,359	838,204
All other properties	Various	12,796	974,979	13,810	1,134,625
Total Volume		337,196	7,155,076	134,555	9,985,590

		Year ended December 31, 2013			
Location (Basin)	Field	Oil (in Bbl)	Natural Gas (Mcfe)	NGLs (in Bbl)	Total (Mcfe)
San Juan	East Blanco	1,421	2,823,795	—	2,832,321
San Juan	All others	—	1,012,972	—	1,012,972
Piceance	Piceance	1,044	1,345,021	9,378	1,407,555
Powder River	Finn Shurley	186,780	361,135	66,939	1,883,450
Powder River	All others	18,833	4,661	—	117,659
Williston	Bakken	125,889	163,805	5,182	950,231
All other properties	Various	2,173	1,271,715	6,706	1,324,990
Total Volume		336,140	6,983,104	88,205	9,529,178

		Year ended December 31, 2012			
Location (Basin)	Field	Oil (in Bbl)	Natural Gas (Mcfe)	NGLs (in Bbl)	Total (Mcfe)
San Juan	East Blanco	1,423	3,584,746	—	3,593,284
San Juan	All others	—	1,338,843	—	1,338,843
Piceance	Piceance	—	1,716,588	5,818	1,751,494
Powder River	Finn Shurley	202,698	441,165	65,287	2,049,073
Powder River	All others	15,757	4,667	—	99,209
Williston[(a)]	Bakken	337,579	404,466	3,799	2,452,732
All other properties	Various	2,514	1,195,716	8,085	1,259,313
Total Volume		559,971	8,686,191	82,989	12,543,948

(a) We sold the majority of our Williston Basin assets in 2012.

Other Information

	As of December 31, 2014		As of December 31, 2013	
Proved developed reserves as a percentage of total proved reserves on an MMcfe basis	88	%	95	%
Proved undeveloped reserves as a percentage of total proved reserves on an MMcfe basis (a)	12	%	5	%
Present value of estimated future net revenues, before tax, discounted at 10% (in thousands)	$188,704		$184,372	

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(a) The increase to proved undeveloped reserves is primarily due to new wells drilled. See Note 20 in the accompanying Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for further details.

The following table reflects average wellhead pricing used in the determination of the reserves:

	December 31, 2014					
	Total	Piceance	San Juan	Williston	Powder River	Other
Gas per Mcf	$3.33	$3.16	$3.41	$4.81	$2.65	$4.01
Oil per Bbl	$85.80	$83.88	$82.84	$83.72	$86.26	$82.03
NGL per Bbl	$34.81	$44.21	$—	$43.56	$28.04	$45.59

	December 31, 2013					
	Total	Piceance	San Juan	Williston	Powder River	Other
Gas per Mcf	$3.45	$4.02	$2.85	$4.10	$3.79	$3.58
Oil per Bbl	$89.79	$83.92	$94.26	$89.38	$90.04	$86.19

	December 31, 2012					
	Total	Piceance	San Juan	Williston	Powder River	Other
Gas per Mcf	$2.24	$2.51	$1.90	$2.05	$3.09	$2.27
Oil per Bbl	$85.31	$94.71	$87.47	$83.34	$85.73	$76.13

Drilling Activity

In 2014, we participated in drilling 33 gross (4 net) development and exploratory wells, with a net well success rate of 100%. A development well is a well drilled within a proved area of a reservoir known to be productive. An exploratory well is a well drilled to find and/or produce oil or gas in an unproved area, to find a new reservoir in a previously productive field or to extend a known reservoir. Gross wells represent the total wells we participated in, regardless of our ownership interest, while net wells represent the sum of our fractional ownership interests within those wells.

The following tables reflect the wells completed through our drilling activities for the last three years.

Year ended December 31,	2014		2013		2012	
Net Development Wells	Productive	Dry	Productive	Dry	Productive	Dry
Piceance	—	—	—	—	—	—
San Juan	—	—	—	—	—	—
Williston	0.26	—	1.00	—	1.80	—
Powder River	—	—	0.19	—	0.74	0.19
Other	—	—	—	—	—	—
Total net development wells	0.26	—	1.19	—	2.54	0.19

Year ended December 31,	2014		2013		2012	
Net Exploratory Wells	Productive	Dry	Productive	Dry	Productive	Dry
Piceance	1.17	—	1.00	—	0.86	—
San Juan	—	—	—	—	—	—
Williston	—	—	—	—	—	—
Powder River	3.00	—	—	1.80	—	—
Other	—	—	0.80	—	—	—
Total net exploratory wells	4.17	—	1.80	1.80	0.86	—

As of December 31, 2014, we were participating in the drilling of 17 gross (8.15 net) wells, which had been commenced but not yet completed.

Recompletion Activity

Recompletion activities for the years ended December 31, 2014, 2013 and 2012 were insignificant to our overall oil and gas operations.

Productive Wells

The following table summarizes our gross and net productive wells at December 31, 2014, 2013 and 2012:

		December 31, 2014				
	Total	Piceance	San Juan	Williston	Powder River	Other [(a)]
Gross Productive:						
Crude Oil	515	1	3	101	401	9
Natural Gas	690	75	155	—	9	451
Total	1,205	76	158	101	410	460
Net Productive:						
Crude Oil	302.38	0.17	2.91	3.32	294.47	1.51
Natural Gas	270.27	62.37	145.15	—	0.23	62.52
Total	572.65	62.54	148.06	3.32	294.70	64.03

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(a) The majority of these wells are non-operated wells.

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	December 31, 2013					
	Total	Piceance	San Juan	Williston	Powder River	Other [(a)]
Gross Productive:						
Crude Oil	519	—	2	75	432	10
Natural Gas	705	74	156	—	9	466
Total	1,224	74	158	75	441	476
Net Productive:						
Crude Oil	301.86	—	1.91	3.03	295.38	1.54
Natural Gas	268.42	60.24	142.60	—	0.21	65.37
Total	570.28	60.24	144.51	3.03	295.59	66.91

(a) The majority of these wells are non-operated wells.

	December 31, 2012					
	Total	Piceance	San Juan	Williston	Powder River	Other [(a)]
Gross Productive:						
Crude Oil	438	—	2	53	379	4
Natural Gas	762	68	212	—	27	455
Total	1,200	68	214	53	406	459
Net Productive:						
Crude Oil	286.52	—	1.91	2.44	281.77	0.40
Natural Gas	326.57	54.76	197.96	—	10.05	63.80
Total	613.09	54.76	199.87	2.44	291.82	64.20

(a) The majority of these wells are non-operated wells.

Acreage

The following table summarizes our undeveloped, developed and total acreage by location as of December 31, 2014:

	Undeveloped		Developed		Total	
	Gross	Net [(a)]	Gross	Net	Gross	Net
Piceance	93,059	69,070	33,698	30,492	126,757	99,562
San Juan	39,649	38,244	25,692	23,562	65,341	61,806
Williston [(b)]	746	64	11,042	1,692	11,788	1,756
Powder River	130,469	80,831	30,732	15,885	161,201	96,716
Bear Paw Uplift (MT)	129,079	37,186	103,771	19,511	232,850	56,697
Other	29,187	15,421	25,806	4,735	54,993	20,156
Total	422,189	240,816	230,741	95,877	652,930	336,693

(a) Approximately 18% (83,300 gross and 43,349 net acres), 15% (42,519 gross and 35,693 net acres) and 3% (12,502 gross and 6,375 net acres) of our undeveloped acreage could expire in 2015, 2016 and 2017, respectively, if production is not established on the leases or further action is not taken to extend the associated lease terms. Decisions on extending leases are based on expected exploration or development potential under the prevailing economic conditions.

(b) Reflects the sale of the majority of our Williston Basin assets in 2012.

Competition. The oil and gas industry is highly competitive. We compete with a substantial number of companies ranging from those that have greater financial resources, personnel, facilities and in some cases technical expertise, to a multitude of smaller, aggressive new start-up companies. Many of these companies explore, produce and market crude oil and natural gas. The primary areas in which we encounter considerable competition are in recruiting and maintaining high quality staff, locating and acquiring leasehold acreage, acquiring producing oil and gas properties, and obtaining sufficient drilling rig and contractor services, acquiring economical costs for drilling and other oil and gas services and marketing our production of oil, gas, and NGLs.

Seasonality of Business. Weather conditions affect the demand for, and prices of, natural gas and can also temporarily inhibit production and delay drilling activities, which in turn impacts our overall business plan. The demand for natural gas is typically higher in the fourth and first quarters of our fiscal year, which sometimes results in higher natural gas prices. Due to these seasonal fluctuations, results of operations on a quarterly basis may not reflect results which may be realized on an annual basis.

Delivery Commitments. In 2012, we entered into a ten-year gas gathering and processing contract for natural gas production from our properties in the Piceance Basin in Colorado, under which we pay a gathering fee per Mcf. This take or pay contract requires us to pay the fee on a minimum of 20,000 Mcf per day, regardless of the volume delivered. The ten-year term of the agreement became effective in first quarter of 2014 upon completion of the processing infrastructure capable of handling the committed volumes.

Operating Regulation. Crude oil and natural gas development and production activities are subject to various laws and regulations governing a wide variety of matters. Regulations often require multiple permits and bonds to drill, complete or operate wells, establish rules regarding the location of wells, well construction, surface use and restoration of properties on which wells are drilled, timing of when drilling and construction activities can be conducted relative to various wildlife and plant stipulations and plugging and abandoning of wells. We are also subject to various mineral conservation laws and regulations, including the regulation of the size of drilling and spacing/proration units, the density of wells that may be drilled in a given field and the unitization or pooling of crude oil and natural gas properties. Some states allow the forced pooling or integration of tracts to facilitate exploration, when voluntary pooling of lands and leases cannot be accomplished. The effect of these regulations may limit the number of wells or the locations where we can drill.

Various federal agencies within the United States Department of the Interior, particularly the Bureau of Land Management, the Office of Natural Resources Revenue and the Bureau of Indian Affairs, along with each Native American tribe, promulgate and enforce regulations pertaining to crude oil and natural gas operations and administration of royalties on federal onshore and tribal lands. These regulations include such matters as lease provisions, drilling and production requirements, environmental standards and royalty considerations. Each Native American tribe is a sovereign nation possessing the power to enforce laws and regulations independent from federal, state and local statutes and regulations. These tribal laws and regulations include various taxes, fees and other conditions that apply to lessees, operators and contractors conducting operations on tribal lands. One or more of these factors may increase our cost of doing business on tribal lands and impact the expansion and viability of our gas, oil and gathering operations on such lands.

In addition to being subject to federal and tribal regulations, we must also comply with state and county regulations, which have been going through significant change over the last several years. New regulations have increased costs and added uncertainty with respect to the timing and receipt of permits. We expect additional changes of this nature to occur in the future.

Environmental Regulations. Our operations are subject to various federal, state and local laws and regulations relating to the discharge of materials into, and the protection of, the environment. We must account for the cost of complying with environmental regulations in planning, designing, drilling, operating and abandoning wells. In most instances, the regulatory requirements relate to the handling and disposal of drilling and production waste products, water and air pollution control procedures (such as spill prevention, control and countermeasure plans, storm water pollution prevention plans, groundwater monitoring, state air quality permits and underground injection control disposal permits), chemical storage use and the remediation of petroleum-product contamination, identifying cultural resources and investigating threatened and endangered species. Certain states, such as Colorado, impose storm water requirements more stringent than the EPA’s and are actively implementing and enforcing these requirements. We take a proactive role in working with these agencies to ensure compliance.

Under state, federal and tribal laws, we could also be required to remove or remediate previously disposed waste, including waste disposed of or released by us, or prior owners or operators, in accordance with current laws, or to otherwise suspend or cease operations in contaminated areas, or to perform remedial well plugging operations or clean-up activities to prevent future contamination. We generate waste that is already subject to the RCRA and comparable state statutes. The EPA and various state agencies limit the disposal options for those wastes. It is possible that certain oil and gas wastes which are currently exempt from regulation such as RCRA wastes may in the future be designated as wastes under RCRA or other applicable statutes.

Hydraulic fracturing is an essential and common practice, which has been used extensively for decades in the oil and gas industry to enhance the production of natural gas and/or oil from dense subsurface rock formations. We routinely apply hydraulic fracturing techniques on our crude oil and natural gas properties. Our hydraulic fracturing mixture is 90% water, 9.5% sand and 0.5% of certain chemical additives to fracture the hydrocarbon-bearing rock formation to enhance flow of hydrocarbons into the well-bore. Chemicals used in the fracturing process are publicly posted as required by state regulations. The process is regulated by state oil and natural gas commissions; however, the EPA does assert federal regulatory authority over certain hydraulic fracturing activities when diesel comprises part of the fracturing fluid. In addition, several agencies of the federal government including the EPA and the BLM are conducting studies of the fracturing stimulation process, which may result in additional regulations. In the event federal, state, local or municipal legal restrictions are adopted in areas where we are conducting, or plan to conduct operations, we may incur additional costs to comply with such regulations, experience delays or curtailment in the pursuit of exploration, development or production activities and perhaps even be precluded from utilizing fracture stimulation which may effectively preclude the drilling of wells. In May 2013, the U.S. Department of the Interior re-proposed rules regulating the use of hydraulic fracturing on Federal and Indian Lands. Final action on these proposed rules is expected in 2015. All of these new or proposed regulations are expected to result in additional costs to our operations.

In 2011 and 2012, the EPA issued several air quality regulations that impact our operations. These include emission standards for reciprocating internal combustion engines (RICE requirements), new source performance standards for VOCs and SO_2 and hazardous air pollutant standards for oil and natural gas production, as well as natural gas transmission and storage (Quad O requirements). Since 2011, we have been in compliance with these new requirements and have been meeting the Quad O green completion requirements (directing flowback gas from natural gas wells to sales) due January 2015.

In 2013, we participated in the State of Colorado's stakeholder process to incorporate EPA Quad O requirements into state regulation. State regulations were finalized in early 2014. New Mexico incorporated Quad O regulations, effective December 19, 2013. Wyoming incorporated Quad O regulations effective January 3, 2014.

Our policy is to meet or exceed all applicable local, state, tribal and federal regulatory requirements when drilling, casing, cementing, completing and producing gas wells that we operate. We follow industry best practices for each project to ensure safety and minimize environmental impacts. Effective wellbore construction and casing design, in accordance with established recommended practices and engineering designs is important to ensure mechanical integrity and isolation from ground water aquifers throughout drilling, hydraulic fracturing and production operations. We place priority on drilling practices that ensure well control throughout the construction and completion phases.

We conduct groundwater sampling before and after our drilling and completion operations. While this is a requirement in Colorado and Wyoming, we conduct this sampling in all states in which we act as the operator for these activities.

Our wells are constructed using one or more layers of steel casing and cement to form a continuous barrier between fluids in the well and the subsurface strata. The only subsurface strata connected to the inside of the wellbore are the intervals that we perforate for the purpose of producing oil and gas. We isolate potential sources of ground water by cementing our surface and/or protection casing back to surface. In areas where additional protection may be necessary or required by regulations, we will cement the intermediate and or production casing string(s) back to surface. The casing is pressure-tested to ensure integrity. We may also run a cement bond log to determine the quality of the bond between the cement and the casing and the cement and the subsurface strata. Surface and/or protection casing string pressures are monitored when a well is stimulated. We also conduct a combination of tests during the life of the well to verify wellbore integrity. Our wells are designed to prevent natural gas and other produced fluids from migrating or leaking for the life of the well. We employ qualified companies to monitor the pressure response to ensure that rate and pressure of fracturing treatment proceeds as planned. Unexpected changes in the rate or pressure are immediately evaluated and necessary action taken. We use the most effective and efficient water management options available. The handling, storage and disposal of produced water meets or exceeds all applicable state, local, tribal and federal regulatory standards and requirements.

Greenhouse Gas Regulations. The EPA promulgated an amendment to its GHG reporting requirements in November 2010, adding Petroleum and Natural Gas Systems to the mandatory annual reporting requirements. Initial data gathering commenced on January 1, 2011, with the first annual report submitted to the EPA in 2012. The EPA added additional reporting requirements in 2011. By the end of 2015, the EPA is expected to further expand this reporting program so that all segments of the industry are included. This is a permanent program, with GHG emission reports now due to the EPA on an annual basis. The Oil and Gas segment is also impacted by GHG regulation in the state of New Mexico. Other states may implement their own such programs in the future.

On January 14, 2015, the Obama Administration announced a goal to reduce methane emissions from the oil and gas sector by 40-45% from 2012 levels, by 2025. Accordingly, the EPA will propose standards for methane and VOC emissions from new and modified oil and gas production sources and natural gas processing and transmission sources. Those rules are due to be proposed in the summer of 2015 with a final rule in 2016. Also by the end of 2015, the EPA will evaluate regulatory opportunities for applying remote sensing technologies to the required identification and quantification of GHG emissions.

In the spring of 2015, the Department of Interior's BLM will propose rules for new and existing oil and gas wells on public lands, targeting reduction or elimination of venting, flaring and leaks of natural gas.

Ozone Regulations. In 2015, the EPA is scheduled to develop guidelines for states to use in reducing ozone-forming pollutants from existing oil and gas systems in areas that do not meet the ozone health standard. The new ozone standards, scheduled to be final by October 2015, could significantly expand the current non-attainment areas and thus increase our costs of operation.

Other Properties

In addition to our electric generation facilities, we own or lease several facilities throughout our service territories. Our owned facilities are as follows:

- In Rapid City, South Dakota, we own an eight-story, 66,000 square foot office building where our corporate headquarters is located, an office building consisting of approximately 36,000 square feet, and a service center, warehouse building and shop with approximately 65,000 square feet.

- In Pueblo, Colorado, we own a building of approximately 46,600 square feet used for a service center and approximately 25,700 square feet used for a warehouse.

- In Cheyenne, Wyoming, we own a business office with approximately 14,300 square feet and a service center and garage with an aggregate of approximately 24,400 square feet.

- In Papillion, Nebraska, we own an office building consisting of approximately 36,600 square feet.

- In Nebraska, Iowa, Colorado and Kansas we own various office, service center, storage, shop and warehouse space totaling over 256,500 square feet utilized by our Gas Utilities.

- In South Dakota, Wyoming, Colorado and Montana we own various office, service center, storage, shop and warehouse space totaling approximately 164,500 square feet utilized by our Electric Utilities and our Coal Mining segments.

In addition to our owned properties, we lease the following properties:

- Approximately 8,800 square feet for an operations and customer call center in Rapid City, South Dakota;

- Approximately 37,600 square feet for a customer call center in Lincoln, Nebraska;
- Approximately 48,400 square feet of office space in Denver, Colorado, of which we sublease approximately 10,100 square feet to a third party;
- Approximately 116,000 square feet of various office, service center and warehouse space leased by the Gas Utilities;
- Approximately 2,000 square feet of various office, service center and warehouse space leased by the Electric Utilities; and
- Other offices and warehouse facilities located within our service areas.

Substantially all of the tangible utility properties of Black Hills Power and Cheyenne Light are subject to liens securing first mortgage bonds issued by Black Hills Power and Cheyenne Light, respectively.

Employees

At December 31, 2014, we had 2,021 full-time employees. Approximately 30% of our employees are represented by a collective bargaining agreement. We have not experienced any labor stoppages in recent years. At December 31, 2014, approximately 27% of our Utilities Group employees were eligible for regular or early retirement.

The following table sets forth the number of employees by business group:

	Number of Employees
Corporate	421
Utilities	1,457
Non-regulated Energy	143
Total	2,021

At December 31, 2014, certain of our Utilities Group employees were covered by the following collective bargaining agreements:

Utility	Number of Employees	Union Affiliation	Expiration Date of Collective Bargaining Agreement
Black Hills Power	140	IBEW Local 1250	March 31, 2017
Cheyenne Light	47	IBEW Local 111	June 30, 2016
Colorado Electric	115	IBEW Local 667	April 15, 2015
Iowa Gas	123	IBEW Local 204	July 31, 2015
Kansas Gas	19	Communications Workers of America, AFL-CIO Local 6407	December 31, 2019
Nebraska Gas	159	IBEW Local 244	March 13, 2017
Total	603		

ITEM 1A. RISK FACTORS

The nature of our business subjects us to a number of uncertainties and risks. The following risk factors and other risk factors that we discuss in our periodic reports filed with the SEC should be considered for a better understanding of our Company. These important factors and other matters discussed herein could cause our actual results or outcomes to differ materially.

OPERATING RISKS

Our current or future development, expansion and acquisition activities may not be successful, which could impair our ability to execute our growth strategy.

Execution of our future growth plan is dependent on successful ongoing and future development, expansion and acquisition activities. We can provide no assurance that we will be able to complete development projects or acquisitions we undertake or continue to develop attractive opportunities for growth. Factors that could cause our development, expansion and acquisition activities to be unsuccessful include:

- Our inability to obtain required governmental permits and approvals or the imposition of adverse conditions upon the approval of any acquisition;
- Our inability to secure adequate utility rates through regulatory proceedings;
- Our inability to obtain financing on acceptable terms, or at all;
- The possibility that one or more credit rating agencies would downgrade our issuer credit rating to below investment grade, thus increasing our cost of doing business;
- Our inability to successfully integrate any businesses we acquire;
- Our inability to attract and retain management or other key personnel;
- Our inability to negotiate acceptable acquisition, construction, fuel supply, power sales or other material agreements;
- The trend of utilities building their own generation or looking for developers to develop and build projects for sale to utilities under turnkey arrangements;
- Reduced growth in the demand for utility services in the markets we serve;
- Changes in federal, state, local or tribal laws and regulations, particularly those which would make it more difficult or costly to fully develop our coal reserves, our oil and gas reserves and our generation capacity;
- Fuel prices or fuel supply constraints;
- Pipeline capacity and transmission constraints;
- Competition within our industry and with producers of competing energy sources; and
- Changes in tax rates and policies.

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Our financial performance depends on the successful operation of our facilities. If the risks involved in our operations are not appropriately managed or mitigated, our operations may not be successful and this could adversely affect our results of operations.

Operating electric generating facilities, oil and gas properties, the coal mine and electric and natural gas distribution systems involves risks, including:

- Operational limitations imposed by environmental and other regulatory requirements;
- Interruptions to supply of fuel and other commodities used in generation and distribution. The Utilities Group purchases fuel from a number of suppliers. Our results of operations could be negatively impacted by disruptions in the delivery of fuel due to various factors, including but not limited to, transportation delays, labor relations, weather and environmental regulations, which could limit the Utilities Group’s ability to operate their facilities;
- Breakdown or failure of equipment or processes, including those operated by PacifiCorp at the Wyodak plant;
- Inability to recruit and retain skilled technical labor;
- Disrupted transmission and distribution. We depend on transmission and distribution facilities, including those operated by unaffiliated parties, to deliver the electricity and gas that we sell to our retail and wholesale customers. If transmission is interrupted, our ability to sell or deliver product and satisfy our contractual obligations may be hindered;
- Operating hazards such as leaks, mechanical problems and accidents, including explosions, affecting our natural gas distribution system which could impact public safety, reliability and customer confidence;
- Electricity is dangerous for employees and the general public should they come in contact with power lines or electrical equipment. Natural conditions and other disasters such as wind, lightning and winter storms can cause wildfires, pole failures and associated property damage and outages. For example, as described in more detail under “Legal Proceedings,” a fire investigator concluded that a forest and grassland fire in the western Black Hills of Wyoming and South Dakota in 2012 was caused by the failure of a transmission structure owned, operated and maintained by Black Hills Power, and claims have been made against us related to the fire;
- Disruption in the functioning of our information technology and network infrastructure which are vulnerable to disability, failures and unauthorized access. If our information technology systems were to fail and we were unable to recover in a timely manner, we would be unable to fulfill critical business functions; and
- Labor relations. Approximately 30% of our employees are represented by a total of six collective bargaining agreements.

Construction, expansion, refurbishment and operation of power generating and transmission and resource extraction facilities involve significant risks which could reduce profitability.

The construction, expansion, refurbishment and operation of power generating and transmission and resource extraction facilities involve many risks, including:

- The inability to obtain required governmental permits and approvals along with the cost of complying with or satisfying conditions imposed upon such approvals;

- Contractual restrictions upon the timing of scheduled outages;
- The cost of supplying or securing replacement power during scheduled and unscheduled outages;
- The unavailability or increased cost of equipment;
- The cost of recruiting and retaining or the unavailability of skilled labor;
- Supply interruptions, work stoppages and labor disputes;

- Increased capital and operating costs to comply with increasingly stringent environmental laws and regulations;
- Opposition by members of public or special-interest groups;
- Weather interferences;
- Availability and cost of fuel supplies;
- Unexpected engineering, environmental and geological problems; and
- Unanticipated cost overruns.

The ongoing operation of our facilities involves many of the risks described above, in addition to risks relating to the breakdown or failure of equipment or processes and performance below expected levels of output or efficiency. New plants may employ recently developed and technologically complex equipment, including newer environmental emission control technology. Any of these risks could cause us to operate below expected capacity levels, which in turn could reduce revenues, increase expenses or cause us to incur higher operating and maintenance costs and penalties. While we maintain insurance, obtain warranties from vendors and obligate contractors to meet certain performance levels, the proceeds of such insurance and our rights under warranties or performance guarantees may not be timely or adequate to cover lost revenues, increased expenses, liability or liquidated damage payments.

Operating results can be adversely affected by variations from normal weather conditions.

Our utility businesses are seasonal businesses and weather patterns can have a material impact on our operating performance. Demand for electricity is typically greater in the summer and winter months associated with cooling and heating. Because natural gas is primarily used for residential and commercial heating, the demand for this product depends heavily upon winter weather patterns throughout our service territory and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating seasons. Accordingly, our utility operations have historically generated lower revenues and income when weather conditions are cooler than normal in the summer and warmer than normal in the winter. Unusually mild summers and winters therefore could have an adverse effect on our financial condition and results of operations.

Our businesses are located in areas that could be subject to seasonal natural disasters such as severe snow and ice storms, flooding and wildfires. These factors could result in interruption of our business, damage to our property such as power lines and substations and repair and clean-up costs associated with these storms. We may not be able to recover the costs incurred in restoring transmission and distribution property following these natural disasters through a change in our regulated rates thereby resulting in a negative impact on our results of operations, financial condition and cash flows.

Our coal mining operations are subject to operating risks that are beyond our control which could affect our profitability and production levels. Our surface mining operations could be disrupted or materially affected due to adverse weather or natural disasters such as heavy snow, strong winds, rain or flooding. Additionally, weather patterns can also affect electricity demand. Extreme temperatures, both hot and cold, cause increased power usage, and therefore, increased generating requirements and the use of coal. Conversely, mild temperatures could result in lower electrical demand.

Weather conditions can also limit or temporarily halt our drilling, completion and producing activities and other crude oil and natural gas operations. Primarily in the winter and spring, our operations can be curtailed because of cold, snow and wet conditions. Severe weather could further curtail these operations, including drilling, and completion of new wells or production from existing wells. In addition, weather conditions and other events could temporarily impair our ability to transport our crude oil and natural gas production.

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Prices for some of our products and services as well as a portion of our operating costs are volatile and may cause our revenues and expenses to fluctuate significantly.

A portion of our net income is attributable to sales of contract and off-system wholesale electricity and natural gas. Energy prices are influenced by many factors outside our control, including, among other things, fuel prices, transmission constraints, supply and demand, weather, general economic conditions, and the rules, regulations and actions of system operators in those markets. Moreover, unlike most other commodities, electricity cannot be stored and therefore must be produced concurrently with its use. As a result, wholesale power markets may be subject to significant, unpredictable price fluctuations over relatively short periods of time.

The success of our crude oil and natural gas operations is affected by the prevailing market prices of crude oil and natural gas. Crude oil and natural gas prices and markets historically have been, and are likely to continue to be, unpredictable. A decrease in crude oil or natural gas prices would not only reduce revenues and profits, but would also reduce the quantities of reserves that are commercially recoverable and may result in charges to earnings for impairment of the net capitalized cost of these assets. Crude oil and natural gas prices are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for crude oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control.

The proliferation of domestic crude oil and natural gas shale plays in recent years has provided the market with an abundant new supply of crude oil and natural gas. The increase in domestic natural gas supply has driven prices down in recent years. The ratio of crude oil to natural gas prices remains at high levels, far in excess of the six to one heating value equivalent ratio. There is also risk that the increased domestic crude oil resources could drive crude oil prices lower.

Our mining operation requires reliable supplies of replacement parts, explosives, fuel, tires and steel-related products. If the cost of these increase significantly, or if sources of supplies and mining equipment become unavailable to meet our replacement demands, our productivity and profitability could be lower than our current expectations. In recent years, industry-wide demand growth exceeded supply growth for certain surface mining equipment and off-the-road tires. As a result, lead times for procuring some items generally increased to several months and prices for these items increased significantly.

Our operations rely on storage and transportation assets owned by third parties to satisfy our obligations. If storage capacity is inadequate or transportation is disrupted, our ability to satisfy our obligations may be hindered.

Our Utilities Group and Power Generation segment rely on pipeline companies and other owners of gas storage facilities to deliver natural gas to ratepayers, to supply our natural gas-fired power plants and to hedge commodity costs. If storage capacity is inadequate or transportation is disrupted, our ability to satisfy our obligations may be hindered. As a result, we may be responsible for damages incurred by our counterparties, such as the additional cost of acquiring alternative supply at then-current market rates, or for penalties imposed by state regulatory authorities.

Threats of terrorism and catastrophic events that could result from terrorism, or individuals and/or groups attempting to disrupt our businesses, or the businesses of third parties, may impact our operations in unpredictable ways and could adversely affect our results of operations, financial position and liquidity.

We are subject to the potentially adverse operating and financial effects of terrorist acts and threats and other disruptive activities of individuals or groups. Our generation, transmission and distribution facilities, fuel storage facilities, information technology systems and other infrastructure facilities and systems and physical assets, could be direct targets of, or indirectly affected by, such activities. Terrorist acts or other similar events could harm our businesses by limiting their ability to generate, purchase or transmit power and by delaying their development and construction of new generating facilities and capital improvements to existing facilities. These events, and governmental actions in response, could result in a material decrease in revenues and significant additional costs to repair and insure our assets and could adversely affect our operations by contributing to disruption of supplies and markets for natural gas, oil and other fuels. They could also impair our ability to raise capital by contributing to financial instability and lower economic activity.

The implementation of security guidelines and measures and maintenance of insurance, to the extent available, addressing such activities could increase costs. These types of events could materially adversely affect our financial results. In addition, these types of events could require significant management attention and resources and could adversely affect our reputation among customers and the public.

A disruption of the regional electric transmission grid, natural gas pipeline infrastructure or other fuel sources, could negatively impact our business. Because generation, transmission systems and natural gas pipelines are part of an interconnected system, we face the risk of possible loss of business due to a disruption caused by the impact of an event on the interconnected system (such as severe weather or a generator or transmission facility outage, pipeline rupture, or a sudden significant increase or decrease in wind generation) within our system or within a neighboring system. Any such disruption could have a material impact on our financial results.

A cyber attack may disrupt our operations, or lead to a loss or misuse of confidential and proprietary information and create a potential liability.

We operate in a highly regulated industry that requires the continuous use and operation of sophisticated information technology systems and network infrastructure. In addition, in the ordinary course of business, we collect and retain sensitive information including personal information about our customers and employees. Cyber attacks targeting our electronic control systems used at our generating facilities and for electric and gas distribution systems, could result in a full or partial disruption of our electric and/or gas operations. Cyber attacks targeting other key information technology systems could further add to a full or partial disruption to our operations. Any disruption of these operations could result in a loss of service to customers and a significant decrease in revenues, as well as significant expense to repair system damage and remedy security breaches. Any theft, loss and/or fraudulent use of customer, shareowner, employee or proprietary data as a result of a cyber attack could subject us to significant litigation, liability and costs, as well as adversely impact our reputation with customers and regulators, among others.

We have instituted security measures and safeguards to protect our operational systems and information technology assets. FERC, through the North American Electric Reliability Corporation, requires certain safeguards be implemented to deter cyber attacks. The security measures and safeguards we have implemented may not always be effective due to the evolving nature and sophistication of cyber attacks. Despite our implementation of security measures and safeguards, all of our information technology systems are vulnerable to disability, failures or unauthorized access, including cyber attacks. If our information technology systems were to fail or be breached by a cyber attack or a computer virus and be unable to recover in a timely way, we would be unable to fulfill critical business functions and sensitive confidential and other data could be compromised which could have a material adverse effect not only on our financial results, but on our public reputation as well.

Increased risks of regulatory penalties could negatively impact our results of operations, financial position or liquidity.

Business activities in the energy sector are heavily regulated, primarily by agencies of the federal government. Agencies that historically sought voluntary compliance, or issued non-monetary sanctions, now employ mandatory civil penalty structures for regulatory violations. The FERC, CFTC, EPA, OSHA, SEC and MSHA may impose significant civil and criminal penalties to enforce compliance requirements relative to our business. In addition, FERC delegated certain aspects of authority for enforcement of electric system reliability standards to the NERC, with similar penalty authority for violations. If a serious regulatory violation occurred and penalties were imposed by FERC or another federal agency, this action could have a material adverse effect on our operations and/or our financial results.

Certain Federal laws, including the Migratory Bird Act and the Endangered Species Act, provide special protection to certain designated species. These laws and any state equivalents provide for significant civil and criminal penalties for non-permitted activities that result in harm to or harassment of certain protected animals, including damage to their habitats. If such species are located in an area in which we conduct operations, or if additional species in those areas become subject to protection, our operations and development projects, particularly transmission, generation, wind, pipeline or drilling projects, could be restricted or delayed, or we could be required to implement expensive mitigation measures.

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Our energy production, transmission and distribution activities involve numerous risks that may result in accidents and other catastrophic events. These events could disrupt or impair our operations, create additional costs and cause substantial loss to us.

Inherent in our natural gas and electricity transmission and distribution activities, as well as our production, transportation and storage of crude oil and natural gas and our coal mining operations, are a variety of hazards and operating risks, such as leaks, blow-outs, fires, releases of hazardous materials, explosions and mechanical problems that could cause substantial adverse financial impacts. These events could result in injury or loss of human life, significant damage to property or natural resources (including public parks), environmental pollution, impairment of our operations and substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events not fully covered by insurance could have a material adverse effect on our financial position and results of operations. Particularly for our transmission and distribution lines located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the damages resulting from any such events could be significant.

Utilities

Regulatory commissions may refuse to approve some or all of the utility rate increases we have requested or may request in the future, or may determine that amounts passed through to customers were not prudently incurred and therefore are not recoverable, which could adversely affect our results of operations, financial position or liquidity.

Our regulated electric and gas utility operations are subject to cost-of-service regulation and earnings oversight from federal and state utility commissions. This regulatory treatment does not provide any assurance as to achievement of desired earnings levels. Our retail electric and gas utility rates are regulated on a state-by-state basis by the relevant state regulatory authorities based on an analysis of our costs, as reviewed and approved in a regulatory proceeding. The rates that we are allowed to charge may or may not match our related costs and allowed return on invested capital at any given time. While rate regulation is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that the state public utility commissions will judge all of our costs, including our direct and allocated borrowing and debt service costs, to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that produce a full recovery of our costs and the return on invested capital allowed by the applicable state public utility commission.

To some degree, each of our gas and electric utilities are permitted to recover certain costs (such as increased fuel and purchased power costs) without having to file a rate case. To the extent we are able to pass through such costs to our customers and a state public utility commission subsequently determines that such costs should not have been paid by the customers; we may be required to refund such costs. Any such costs not recovered through rates, or any such refund, could adversely affect our results of operations, financial position or cash flow.

If regulatory commissions refuse to approve the implementation of a cost of service gas program to serve our natural gas utilities and the fuel needs of our electric utilities, it could adversely affect future operations or require us to make changes to our business strategy.

We are evaluating the implementation of a program supporting our natural gas and electric utilities that can provide longer-term price stability for our regulated customers by enhancing our current utility gas supply portfolio, through the addition of utility or affiliate owned natural gas production and reserves. In addition to providing our customers the benefits associated with more predictable long-term commodity prices, it also provides additional opportunities for increased earnings. We will require regulatory approval from our state commissions to implement this program. If regulatory commissions refuse to approve the program, we may have to reconsider our long-term strategy, including the potential for vertical integration of our oil and gas operations in support of this program.

If market or other conditions adversely affect operations or require us to make changes to our business strategy in any of our utility businesses, we may be forced to record a non-cash goodwill impairment charge. Any significant impairment of our goodwill related to these utilities would cause a decrease in our assets and a reduction in our net income and shareholders' equity.

We had approximately $353 million of goodwill on our consolidated balance sheets as of December 31, 2014. A substantial portion of the goodwill is related to the Aquila Transaction. If we make changes in our business strategy or if market or other conditions adversely affect operations in any of our businesses, we may be forced to record a non-cash impairment charge, which would reduce our reported assets, net income and shareholders' equity. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. If the testing performed indicates that impairment has occurred, we are required to record an impairment charge for the difference between the carrying value of the goodwill and the implied fair value of the goodwill in the period the determination is made. The testing of goodwill for impairment requires us to make significant estimates about our future performance and cash flows, as well as other assumptions. These estimates can be affected by numerous factors, including: future business operating performance, changes in economic conditions and interest rates, regulatory, industry or market conditions, changes in business operations, changes in competition or changes in technologies. Any changes in key assumptions, or actual performance compared with key assumptions, about our business and its future prospects could affect the fair value of one or more business segments, which may result in an impairment charge.

Municipal governments may seek to limit or deny franchise privileges which could inhibit our ability to secure adequate recovery of our investment in assets subject to condemnation.

Municipal governments within our utility service territories possess the power of condemnation and could establish a municipal utility within a portion of our current service territories by limiting or denying franchise privileges for our operations and exercising powers of condemnation over all or part of our utility assets within municipal boundaries. Although condemnation is a process that is subject to constitutional protections requiring just and fair compensation, as with any judicial procedure, the outcome is uncertain. If a municipality sought to pursue this course of action, we cannot assure that we would secure adequate recovery of our investment in assets subject to condemnation.

Power Generation

Our ability to execute the purchase option for the sale of Wygen I to Cheyenne Light Fuel & Power could adversely affect our Power Generation segment.
Black Hills Wyoming has a power sales agreement with Cheyenne Light which expires in December 2022. This power sales agreement includes an option for Cheyenne Light to purchase Black Hills Wyoming's ownership interest in the Wygen I facility until 2019. This purchase by Cheyenne Light, estimated to be approximately $154 million at December 31, 2014, would be subject to WPSC approval in order to obtain regulatory treatment. The inability to obtain power sales contracts at reasonable rates to fully utilize these assets subsequent to the expiration of long-term contracts could affect our results of operations, financial position and liquidity.

Coal Mining

If the assumptions underlying our reclamation and mine closure obligations are materially inaccurate, our costs could be significantly greater than anticipated or be incurred sooner than anticipated.

Our mining consists of surface mining operations. The Surface Mining Control and Reclamation Act and similar state laws and regulation establish operations, reclamation and closure standards for all aspects of surface mining. We estimate our total reclamation liabilities based on permit requirements, engineering studies and our engineering expertise related to these requirements. The estimate of ultimate reclamation liability is reviewed periodically by our management and engineers and by government regulators. The estimated liability can change significantly if actual costs vary from our original assumptions or if government regulations change significantly. GAAP requires that asset retirement obligations be recorded as a liability based on fair value, which reflects the present value of the estimated future cash flows. In estimating future cash flows, we consider the estimated current cost of reclamation and apply inflation rates. The resulting estimated reclamation obligations could change significantly if actual amounts or the timing of these expenses change significantly from our assumptions, which could have a material adverse effect on our results of operations and financial condition.

Estimates of the quality and quantity of our coal reserves may change materially due to numerous uncertainties inherent in three dimensional structural modeling. Significant inaccuracies in interpretation or modeling could materially affect the estimated quantity and quality of our reserve which could adversely affect our results of operations.

There are many uncertainties inherent in estimating quantities of coal reserves. The process of coal volume estimation requires interpretations of drill hole log data and subsequent computer modeling of the intersected deposit. Significant inaccuracies in interpretation or modeling could materially affect the quantity and quality of our reserve estimates. The accuracy of reserve estimates is a function of engineering and geological interpretation, conditions encountered during actual reserve recovery and undetected deposit anomalies. Variance from the assumptions used and drill hole modeling density could result in additions or deletions from our volume estimates. In addition, future environmental, economic or geologic changes may occur or become known that require reserve revisions either upward or downward from prior reserve estimates.

Oil and Gas

Estimates of the quantity and value of our proved oil and gas reserves may change materially due to numerous uncertainties inherent in estimating oil and natural gas reserves. Significant inaccuracies in interpretations or assumptions could materially affect the estimated quantities and present value of our reserves which could adversely affect our results of operations.

There are many uncertainties inherent in estimating quantities of proved reserves and their associated value. The process of estimating crude oil and natural gas reserves requires interpretation of available technical data and various assumptions, including assumptions relating to economic factors. Significant inaccuracies in interpretations or assumptions could materially affect the estimated quantities and present value of our reserves. The accuracy of reserve estimates is a function of the quality of available data, engineering and geological interpretations and judgment and the assumptions used regarding quantities of recoverable oil and gas reserves, future capital expenditures and prices for crude oil and natural gas. Actual prices, production, development expenditures, operating expenses and quantities of recoverable crude oil and natural gas reserves may vary from those assumed in our estimates. These variances may be significant. Any significant variance from the assumptions used could cause the actual quantity of our reserves and future net cash flow to be materially different from our estimates. In addition, results of drilling, testing and production, changes in future capital expenditures and fluctuations in crude oil and natural gas prices after the date of the estimate may result in substantial upward or downward revisions.

The potential adoption of federal and state legislative and regulatory initiatives related to hydraulic fracturing could result in restrictions which could increase costs and cause delays to the completion of certain oil and gas wells and potentially preclude the economic drilling and completion of wells in certain reservoirs.

Hydraulic fracturing is an essential and common practice in the oil and gas industry used extensively for decades to stimulate production of natural gas and/or oil from dense subsurface rock formations. We routinely apply hydraulic fracturing techniques on our crude oil and natural gas properties. Hydraulic fracturing involves using mostly water, sand and a small amount of certain chemicals to fracture the hydrocarbon-bearing rock formation to enhance flow of hydrocarbons into the well-bore. The process is typically regulated by state crude oil and natural gas commissions; however, the EPA does assert federal regulatory authority over certain hydraulic fracturing activities when diesel comprises part of the fracturing fluid. In addition several agencies of the federal government including the EPA and the BLM are conducting studies of the fracturing stimulation process which may result in additional regulations. In May 2013, the U.S. Department of the Interior re-proposed rules regulating the use of hydraulic fracturing on Federal and Indian Lands, with final action expected in 2015. In addition, legislation has been introduced before Congress, called the Fracturing Responsibility and Awareness of Chemicals Act, to provide the federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process.

Certain states have adopted or are considering adopting regulations that could impose more stringent permitting, public disclosure and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In the event federal, state, local or municipal legal restrictions on the hydraulic fracturing are adopted in areas where we are conducting or in the future plan to conduct operations, we may incur additional costs to comply with such regulations that may be significant, experience delays or curtailment in the pursuit of exploration, development or production activities and perhaps even be precluded from utilizing fracture stimulation and effectively preclude the drilling of wells.

Exploratory and development drilling are speculative activities that may not result in commercially productive reserves. Lack of drilling success could result in uneconomical investments and could have an adverse effect on our financial condition and results of operations.

Drilling activities are subject to many risks, including the risk that no commercially productive oil or gas reservoirs will be encountered. There can be no assurance that new wells drilled by us or in which we have an interest will be productive or that we will recover all or any portion of our investment. Drilling for oil and gas may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. The cost of drilling, completing and operating wells is often uncertain. Our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, many of which are beyond our control, including economic conditions, mechanical problems, pressure or irregularities in formations, title problems, weather conditions, compliance with governmental rules and regulations and shortages in or delays in the delivery of equipment and services. Such equipment shortages and delays are caused by the high demand for rigs and other needed equipment by a large number of companies in active drilling basins. High activity in some basins may cause shortages of rigs and equipment in other basins. Our future drilling activities may not be successful. Lack of drilling success could have a material adverse effect on our financial condition and results of operations.

We could incur additional and substantial write-downs of the carrying value of our natural gas and oil properties, which would cause a decrease in our assets and stockholders' equity and could adversely impact our results of operations.

We review the carrying value of our natural gas and oil properties under the full cost accounting rules of the SEC on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. In calculating future net revenues, SEC-defined commodity prices and recent costs are utilized. Such prices and costs are utilized except when different prices and costs are fixed and determinable from applicable contracts for the remaining term of those contracts. Two primary factors in the ceiling test are natural gas and crude oil reserve quantities and SEC-defined crude oil and gas prices, both of which impact the present value of estimated future net revenues. Revisions to estimates of natural gas and crude oil reserves, or an increase or decrease in prices, can have a material impact on the present value of estimated future net revenues. The amount by which net book value, less deferred income tax, exceeds the tax adjusted net present value of reserves is written off as an expense.

We recorded a non-cash impairment charge in the second quarter of 2012 due to the full cost ceiling limitations. Using our year-end reserve information and holding all other variables constant, a price sensitivity analysis indicates it is probable a ceiling impairment charge will occur in 2015 if crude oil and natural gas prices remain at or near the low levels experienced in late 2014 and early 2015. See Note 12 to the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

FINANCING RISKS

Our credit ratings could be lowered below investment grade in the future. If this were to occur, it could impact our access to capital, our cost of capital and our other operating costs.

Our issuer credit rating is Baa1 (Stable outlook) by Moody’s; BBB (Stable outlook) by S&P; and BBB+ (Stable outlook) by Fitch. Reduction of our credit ratings could impair our ability to refinance or repay our existing debt and to complete new financings on reasonable terms, or at all. A credit rating downgrade, particularly to a sub-investment grade, could also result in counterparties requiring us to post additional collateral under existing or new contracts or trades. In addition, a ratings downgrade would increase our interest expense under some of our existing debt obligations, including borrowings under our credit facilities.

Derivatives regulations included in current financial reform legislation could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices and interest rates.

In July 2010, Dodd-Frank was passed by Congress and signed into law. Dodd-Frank contains significant derivatives regulations, including a requirement that certain transactions be cleared resulting in a requirement to post cash collateral (commonly referred to as “margin”) for such transactions. Dodd-Frank provides for a potential exception from these clearing and cash collateral requirements for commercial end-users such as utilities and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and the parties to those transactions.

We use crude oil and natural gas derivative instruments for our hedging activities for our oil and gas production activities and our gas utility operations. We also use interest rate derivative instruments to minimize the impact of interest rate fluctuations. As a result of Dodd-Frank regulations promulgated by the CFTC, we may be required to post collateral to clearing entities for certain swap transactions we enter into. In addition, many of the transactions which were previously classified as swaps have been converted to exchange-traded futures contracts, which are subject to futures margin posting requirements. Such a requirement could have a significant impact on our business by reducing our ability to execute derivative transactions to reduce commodity price and interest rate uncertainty and to protect cash flows. Requirements to post collateral may cause significant liquidity issues by reducing our ability to use cash for investment or other corporate purposes, or may require us to increase our level of debt. In addition, a requirement for our counterparties to post collateral could result in additional costs being passed on to us, thereby decreasing our profitability.

Our hedging activities that are designed to protect against commodity price and financial market risks may cause fluctuations in reported financial results due to accounting requirements associated with such activities.

We use various financial contracts and derivatives, including futures, forwards, options and swaps to manage commodity price and financial market risks. The timing of the recognition of gains or losses on these economic hedges in accordance with GAAP does not always match up with the gains or losses on the commodities or assets being hedged. The difference in accounting can result in volatility in reported results, even though the expected profit margin may be essentially unchanged from the dates the transactions were consummated.

Our use of derivative financial instruments could result in material financial losses.

From time to time, we have sought to limit a portion of the potential adverse effects resulting from changes in commodity prices and interest rates by using derivative financial instruments and other hedging mechanisms. To the extent that we hedge our commodity price and interest rate exposures, we forgo the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, even though they are closely monitored by management, our hedging activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the hedge arrangement, the hedge is economically imperfect, commodity prices or interest rates move unfavorably related to our physical or financial positions, or hedging policies and procedures are not followed.

Market performance or changes in other assumptions could require us to make significant unplanned contributions to our pension plans and other postretirement benefit plans. Increasing costs associated with our defined benefit retirement plans may adversely affect our results of operations, financial position or liquidity.

We have two defined benefit pension plans and three non-pension postretirement plans that cover certain eligible employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements and the expense recognized related to these plans. These estimates and assumptions may change based on actual return on plan assets, changes in interest rates and any changes in governmental regulations.

We have a holding company corporate structure with multiple subsidiaries. Corporate dividends and debt payments are dependent upon cash distributions to the holding company from the subsidiaries. The subsidiaries may not be allowed or may be unable to make dividend payments or loan funds to the holding company, which could adversely affect our ability to meet our financial obligations or pay dividends to our shareholders.

We are a holding company. Our investments in our subsidiaries are our primary assets. Our operating cash flow and ability to service our indebtedness depend on the operating cash flow of our subsidiaries and the payment of funds by them to us in the form of dividends or advances. Our subsidiaries are separate legal entities that have no obligation to make any funds available for that purpose, whether by dividends or otherwise. In addition, each subsidiary's ability to pay dividends to us depends on any applicable contractual or regulatory restrictions that may include requirements to maintain minimum levels of cash, working capital or debt service funds.

We expect to continue our policy of paying regular cash dividends. However, there is no assurance as to the amount of future dividends because they depend on our future earnings, capital requirements and financial conditions and are subject to declaration by the Board of Directors. Our operating subsidiaries have certain restrictions on their ability to transfer funds in the form of dividends or loans to us. See "Liquidity and Capital Resources" within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K for further information regarding these restrictions and their impact on our liquidity.

We may be unable to obtain the financing needed to refinance debt, fund planned capital expenditures or otherwise execute our operating strategy. Lack of credit at reasonable rates would have an adverse effect on our results of operations, financial position and liquidity.

Our ability to execute our operating strategy is highly dependent upon our access to capital. Historically, we have addressed our liquidity needs (including funds required to make scheduled principal and interest payments, refinance debt and fund working capital and planned capital expenditures) with operating cash flow, borrowings under credit facilities, proceeds of debt and equity offerings and proceeds from asset sales. Our ability to access the capital markets and the costs and terms of available financing depend on many factors, including changes in our credit ratings, changes in the federal or state regulatory environment affecting energy companies, volatility in commodity or electricity prices and general economic and market conditions.

In addition, because we are a holding company and our utility assets are owned by our subsidiaries, if we are unable to adequately access the credit markets, we could be required to take additional measures designed to ensure that our utility subsidiaries are adequately capitalized to provide safe and reliable service. Possible additional measures would be evaluated in the context of then-prevailing market conditions, prudent financial management and any applicable regulatory requirements.

National and regional economic conditions may cause increased counterparty credit risk, late payments and uncollectible accounts, which could adversely affect our results of operations, financial position and liquidity.

A future recession may lead to an increase in late payments from retail, commercial and industrial utility customers, as well as our non-utility customers. If late payments and uncollectible accounts increase, earnings and cash flows from our continuing operations may be reduced.

Our ability to obtain insurance and the terms of any available insurance coverage could be adversely affected by international, national, state or local events and company-specific events, as well as the financial condition of insurers. Our insurance coverage may not provide protection against all significant losses.

Our ability to obtain insurance, as well as the cost of such insurance, could be affected by developments affecting insurance businesses, international, national, state or local events, as well as the financial condition of insurers. Insurance coverage may not continue to be available at all, or at rates or on terms similar to those presently available to us. A loss for which we are not fully insured could materially and adversely affect our financial results. Our insurance may not be sufficient or effective under all circumstances and against all hazards or liabilities to which the Company may be subject, including but not limited to environmental hazards, fire-related liability from natural events or inadequate facility maintenance, risks associated with our oil and gas exploration and production activities, distribution property losses, cyber-security risks and dangers that exist in the gathering and transportation in pipelines.

Our operations are also subject to all the hazards and risks normally incident to the development, exploitation, production and transportation of, and the exploration for, oil and gas, including unusual or unexpected geologic formations, pressures, down hole fires, mechanical failures, blowouts, explosions, uncontrollable flows of oil, gas or well fluids, pollution and other environmental risks. These hazards could result in substantial losses to us due to injury and loss of life, severe damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations. We maintain insurance coverage for our operated wells and we participate in insurance coverage maintained by the operators of our wells, although there can be no assurances that such coverage will be sufficient to prevent a material adverse effect to us if any of the foregoing events occur.

Increasing costs associated with our health care plans and other benefits may adversely affect our results of operations, financial position or liquidity.

The costs of providing health care benefits to our employees and retirees have increased substantially in recent years. We believe that our employee benefit costs, including costs related to health care plans for our employees and former employees, will continue to rise. The increasing costs and funding requirements associated with our health care plans may adversely affect our results of operations, financial position or liquidity.

In March 2010, the President of the United States signed PPACA as amended by the Health Care and Education Reconciliation Act of 2010 (collectively, the "2010 Acts"). The 2010 Acts will have a substantial impact on health care providers, insurers, employers and individuals. The 2010 Acts will impact employers and businesses differently depending on the size of the organization and the specific impacts on a company's employees. Certain provisions of the 2010 Acts are effective while other provisions of the 2010 Acts will be effective in future years. The 2010 Acts could require, among other things, changes to our current employee benefit plans and in our administrative and accounting processes, as well as changes to the cost of our plans. The ultimate extent and cost of these changes cannot be determined at this time and are being evaluated and updated as related regulations and interpretations of the 2010 Acts become available.

Our electric and gas utility rates are regulated on a state-by-state basis by the relevant state regulatory authorities based on an analysis of our costs, as reviewed and approved in a regulatory proceeding. Within our utility rates we have generally recovered the cost of providing employee benefits. As benefit costs continue to rise, there can be no assurance that the state public utility commissions will allow recovery.

We have deferred a substantial amount of income tax related to various tax planning strategies, including the deferral of a gain associated with the assets sold in the IPP Transaction. If the Internal Revenue Service successfully challenges these tax positions, our results of operations, financial position or liquidity could be adversely affected.

We have deferred a substantial amount of tax payments through various tax planning strategies including the deferral of approximately $125 million in income taxes associated with a like-kind exchange related to the IPP Transaction and the Aquila Transaction.

The IRS has challenged our position with respect to the like-kind exchange. As stated in a revised Notice of Proposed Adjustment received from the IRS in April 2013, their position is to disallow a significant portion of the gain deferred as reported on our originally filed 2008 tax return. A 30 Day Letter along with a Revenue Agent's Report were received on July 30, 2014, indicating no change in the IRS' position. We disagree with such a position and will pursue all available IRS and/or legal channels to challenge the proposed adjustment. A protest was timely filed with IRS Appeals in August 2014. In the event we are unsuccessful in our challenge, the amount of deferred income tax on a worst case basis that could be accelerated into a current taxes payable based on the revised NOPA would be approximately $88 million. However, we would be entitled to a cash tax benefit associated with the additional tax depreciation that would result from increasing the depreciable cost for tax purposes in the assets acquired. This net current tax liability would accrue interest, which is estimated to be approximately $19 million before income tax effect.

In certain circumstances, the IRS may assess penalties when challenging our tax positions. If we were unsuccessful in defending against these penalties, it may have a material impact on our results of operations. No penalties have been assessed by the IRS in connection with the like-kind exchange transaction.

An effective system of internal control may not be maintained, leading to material weaknesses in internal control over financial reporting.

Section 404 of the Sarbanes-Oxley Act of 2002 requires management to make an assessment of the design and effectiveness of internal controls. Our independent registered public accounting firm is required to attest to the effectiveness of these controls. During their assessment of these controls, management or our independent registered public accounting firm may identify areas of weakness in control design or effectiveness, which may lead to the conclusion that a material weakness in internal control exists. Any control deficiencies we identify in the future could adversely affect our ability to report our financial results on a timely and accurate basis, which could result in a loss of investor confidence in our financial reports or have a material adverse effect on our ability to operate our business or access sources of liquidity.

ENVIRONMENTAL RISKS

Federal and state laws concerning greenhouse gas regulations and air emissions may materially increase our generation and production costs and could render some of our generating units uneconomical to operate and maintain. We own and operate regulated and non-regulated fossil-fuel generating plants in South Dakota, Wyoming and Colorado. Recent developments under federal and state laws and regulations governing air emissions from fossil-fuel generating plants will likely result in more stringent emission limitations, which could have a material impact on our costs of operations. Various pending or final state and EPA regulations that will impact our facilities are also discussed in Item 1 of this Annual Report on Form 10-K under the caption “Environmental Matters.”

On May 20, 2011, with amendments on December 21, 2012, the EPA's Industrial and Commercial Boiler regulations became effective, which provide for hazardous air pollutant-related emission limits and monitoring requirements. The compliance deadline for this rule was March 21, 2014. Engineering evaluations were completed and confirmed the significant impact on our Neil Simpson I, Osage and Ben French facilities. These units were permanently retired on March 21, 2014. We have requested recovery for the remaining net book values of these plants and prudent decommissioning costs of these units. The WPSC granted approval to our request in the Wyoming rate case approved in August 2014, and our request with the SDPUC is pending with a decision expected in March 2015.

On February 16, 2012, the EPA published in the Federal Register the National Emission Standards for Hazardous Air Pollutants from Coal and Oil Fired Electric Utility Steam Generating Units (MATS), with an effective date of April 16, 2012. Affected units have a compliance deadline of April 16, 2015, with a pathway defined to apply for a one year extension due to certain circumstances. It is expected that all of our plants will be in compliance by the initial 2015 deadline, with the primary impacts to Neil Simpson II, Wygen I, Wygen II, Wygen III and the Wyodak Plant including installation of mercury sorbent injection systems, along with additional monitoring and testing requirements.

The GHG Tailoring Rule, implementing regulations of GHG for permitting purposes, became effective in June 2010. This rule will impact us in the event of a major modification at an existing facility or in the event of a new major source as defined by EPA regulations. Upon renewal of operating permits for existing facilities, monitoring and reporting requirements will be implemented. New projects or major modifications to existing projects will result in a Best Available Control Technology review that could impose more stringent emissions control practices and technologies. The EPA's GHG New Source Performance Standard for new steam electric generating units was expected to be final by the end of 2014. As proposed, it effectively prohibits new coal fired units until carbon capture and sequestration becomes technically and economically feasible. It also effectively prohibits simple cycle natural gas combustion turbines from generating more than one-third of their capacity, averaged over a three year period. The rule was not finalized in 2014 and may be delayed to June 2015 to coincide with issuance of the Clean Power Plan regulations.

On June 2, 2014, the EPA proposed the Clean Power Plan to cut carbon emissions from existing electric generating units. The design of the Clean Power Plan is to decrease existing coal-fired generation, increase the utilization of existing gas generation, increase renewable energy and demand side management. This rule could have a significant impact on our coal and natural gas generating fleet. The rule calls for states to develop plans to meet their assigned emission rate targets by 2030. The rule also allows states to formulate a regional approach whereby they would join with other states and be assigned a new single target for the group. We are currently evaluating this proposal, but cannot predict the impact on operations as this rule is expected to be final in June 2015. State plans are expected to be due at the earliest in June 2016, with extensions possible to 2017 and 2018.

Due to uncertainty as to the final outcome of federal climate change legislation, or regulatory changes under the Clean Air Act, we cannot definitively estimate the effect of GHG legislation or regulation on our results of operations, cash flows or financial position. The impact of GHG legislation or regulation on our company will depend upon many factors, including but not limited to, the timing of implementation, the GHG sources that are regulated, the overall GHG emissions cap level and the availability of technologies to control or reduce GHG emissions. If a "cap and trade" structure is implemented, the impact will depend on the degree to which offsets are allowed, the allocation of emission allowances to specific sources and the effect of carbon regulation on natural gas and coal prices.

New or more stringent regulations or other energy efficiency requirements could require us to incur significant additional costs relating to, among other things, the installation of additional emission control equipment, the acceleration of capital expenditures, the purchase of additional emissions allowances or offsets, the acquisition or development of additional energy supply from renewable resources and the closure of certain generating facilities. To the extent our regulated fossil-fuel generating plants are included in rate base we will attempt to recover costs associated with complying with emission standards or other requirements. We will also attempt to recover the emission compliance costs of our non-regulated fossil-fuel generating plants from utility and other purchasers of the power generated by those non-regulated power plants. Any unrecovered costs could have a material impact on our results of operations and financial condition. In addition, future changes in environmental regulations governing air emissions could render some of our power generating units more expensive or uneconomical to operate and maintain.

The failure to achieve or maintain compliance with existing or future governmental laws, regulations or requirements could adversely affect our results of operations, financial position or liquidity. Additionally, the potentially high cost of complying with such requirements or addressing environmental liabilities could also adversely affect our results of operations, financial position or liquidity.

Our business is subject to extensive energy, environmental and other laws and regulations of federal, state, tribal and local authorities. We generally must obtain and comply with a variety of regulations, licenses, permits and other approvals in order to operate, which can require significant capital expenditure and operating costs. If we fail to comply with these requirements, we could be subject to civil or criminal liability and the imposition of penalties, liens or fines, claims for property damage or personal injury, or environmental clean-up costs. In addition, existing regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to us or our facilities, which could require additional unexpected expenditures or cause us to reevaluate the feasibility of continued operations at certain sites and have a detrimental effect on our business.

In connection with certain acquisitions, we assumed liabilities associated with the environmental condition of certain properties, regardless of when such liabilities arose, whether known or unknown, and in some cases agreed to indemnify the former owners of those properties for environmental liabilities. Future steps to bring our facilities into compliance or to address contamination from legacy operations, if necessary, could be expensive and could adversely affect our results of operation and financial condition. We expect our environmental compliance expenditures to be substantial in the future due to the continuing trends toward stricter standards, greater regulation, more extensive permitting requirements and an increase in the number of assets we operate.

The characteristics of coal may make it difficult for coal users to comply with various environmental standards related to coal combustion or utilization and the use of alternative energy sources for power generation as mandated by states could reduce coal consumption. As a result, coal users may switch to other fuels, which would affect the volume of our sales and the price of our products.

Coal contains impurities, including but not limited to sulfur, mercury, chlorine, carbon and other elements or compounds, many of which are released into the air when coal is burned. More stringent environmental regulations of emissions from coal-fueled power plants could increase the costs of using coal, thereby reducing demand for coal as a fuel source and the volume and price of our coal sales. Renewable energy requirements and changes to regulations could make coal a less attractive fuel alternative in the planning and building of power plants in the future.

Proposed reductions in emissions of mercury, sulfur dioxides, nitrogen oxides, particulate matter, or greenhouse gases may require the installation of costly emission control technology or the implementation of other measures. For example, in order to meet the federal Clean Air Act limits for SO_2 emission from power plants, coal users may need to install scrubbers, use SO_2 emission allowances (some of which they may purchase), blend high-sulfur coal with low-sulfur coal or switch to other fuels. Reductions in mercury emission required by certain states and the EPA will likely require some power plants to install new equipment, at substantial cost, or discourage the use of certain coals containing higher levels of mercury. On June 2, 2014, the EPA proposed the Clean Power Plan to cut carbon emissions from existing electric generating units. The design of the Clean Power Plan is to decrease existing coal-fired generation, increase the utilization of existing gas generation, increase renewable energy and demand side management. This rule could have a significant impact on our coal and natural gas generating fleet. The rule calls for states to develop plans to meet their assigned emission rate targets by 2030. The rule also allows states to formulate a regional approach whereby they would join with other states and be assigned a new single target for the group. We are currently evaluating this proposal, but cannot predict the impact on operations as this rule is expected to be final in June 2015. State plans are expected to be due at the earliest in June 2016, with extensions possible to 2017 and 2018.

Coal competes with other energy sources, such as natural gas, wind, solar and hydropower. If the Clean Power Plan Rule regulations were to have an adverse effect on coal as a domestic energy source, this rule could have a significant impact on our coal mining operations.

Existing or proposed legislation focusing on emissions enacted by the United States or individual states could make coal a less attractive fuel alternative for our customers and could impose a tax or fee on the producer of the coal. If our customers decrease the volume of coal they purchase from us or switch to alternative fuels as a result of existing or future environmental regulations aimed at reducing emissions, our operations and financial results could be adversely impacted.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

Information regarding our legal proceedings is incorporated herein by reference to the "Legal Proceedings" sub-caption within Item 8, Note 18, "Commitments and Contingencies", of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

ITEM 4. MINE SAFETY DISCLOSURES

Information concerning mine safety violations or other regulatory matters required by Sections 1503(a) of Dodd-Frank is included in Exhibit 95 of this Annual Report.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is traded on the New York Stock Exchange under the symbol BKH. As of December 31, 2014, we had 4,155 common shareholders of record and approximately 26,000 beneficial owners, representing all 50 states, the District of Columbia and 10 foreign countries.

We have paid a regular quarterly cash dividend each year since the incorporation of our predecessor company in 1941 and expect to continue paying a regular quarterly dividend for the foreseeable future. At its January 28, 2015 meeting, our Board of Directors declared a quarterly dividend of $0.405 per share, equivalent to an annual dividend of $1.62 per share, marking 2015 as the 45th consecutive annual dividend increase for the Company.

For additional discussion of our dividend policy and factors that may limit our ability to pay dividends, see "Liquidity and Capital Resources" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this Annual Report on Form 10-K.

Quarterly dividends paid and the high and low prices for our common stock, as reported in the New York Stock Exchange Composite Transactions, for the last two years were as follows:

Year ended December 31, 2014	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$0.390	$0.390	$0.390	$0.390
Common stock prices				
High	$59.05	$61.41	$62.13	$57.17
Low	$51.09	$55.23	$47.87	$47.11

Year ended December 31, 2013	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$0.380	$0.380	$0.380	$0.380
Common stock prices				
High	$44.32	$50.53	$55.09	$54.83
Low	$36.89	$43.19	$46.62	$47.00

UNREGISTERED SECURITIES ISSUED

There were no unregistered securities sold during 2014.

ISSUER PURCHASES OF EQUITY SECURITIES

There were no equity securities acquired for the three months ended December 31, 2014.

ITEM 6. SELECTED FINANCIAL DATA

Years Ended December 31, (dollars in thousands, except per share amounts)	2014	2013	2012	2011	2010
Total Assets	$4,279,806	$3,875,178	$3,729,471	$4,127,083	$3,711,509
Property, Plant and Equipment					
Total property, plant and equipment	$4,563,400	$4,259,445	$3,930,772	$3,724,016	$3,353,509
Accumulated depreciation and depletion	$(1,324,025)	$(1,269,148)	$(1,188,023)	$(934,441)	$(861,775)
Capital Expenditures	$391,267	$379,534	$347,980	$431,707	$496,990
Capitalization					
Current maturities of long-term debt	$275,000	$—	$103,973	$2,473	$5,181
Notes payable	75,000	82,500	277,000	345,000	249,000
Long-term debt, net of current maturities	1,267,589	1,396,948	938,877	1,280,409	1,186,050
Common stock equity	1,376,024	1,307,748	1,232,509	1,209,336	1,100,270
Total capitalization	$2,993,613	$2,787,196	$2,552,359	$2,837,218	$2,540,501
Capitalization Ratios					
Short-term debt, including current maturities	12 %	3 %	15 %	12 %	10 %
Long-term debt, net of current maturities	42 %	50 %	37 %	45 %	47 %
Common stock equity	46 %	47 %	48 %	43 %	43 %
Total	100 %	100 %	100 %	100 %	100 %
Total Operating Revenues	$1,393,570	$1,275,852	$1,173,884	$1,272,188	$1,219,691
Net Income Available for Common Stock					
Utilities	$101,421	$84,841	$79,588	$81,860	$74,563
Non-regulated Energy	28,335	18,403 (1)	24,725 (1)	866	10,189
Corporate and intersegment eliminations	(975)	12,602 (2)	(15,808) (2)	(42,361) (2)	(21,611) (2)
Income (loss) from continuing operations	128,781	115,846	88,505	40,365	63,141
Income (loss) from discontinued operations, net of tax (3)	—	(884)	(6,977)	9,365	5,544
Net income available for common stock	$128,781	$114,962	$81,528	$49,730	$68,685

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SELECTED FINANCIAL DATA continued

Years Ended December 31, (dollars in thousands, except per share amounts)	2014	2013	2012	2011	2010
Dividends Paid on Common Stock	$69,636	$67,587	$65,262	$59,202	$56,467
Common Stock Data[(4)] (in thousands)					
Shares outstanding, average basic	44,394	44,163	43,820	39,864	38,916
Shares outstanding, average diluted	44,598	44,419	44,073	40,081	39,091
Shares outstanding, end of year	44,672	44,499	44,206	43,925	39,269
Earnings (Loss) Per Share of Common Stock (in dollars) [(4)]					
Basic earnings (loss) per average share -					
Continuing operations	$2.90	$2.62	$2.02	$1.01	$1.62
Discontinued operations	—	(0.02)	(0.16)	0.24	0.14
Total	$2.90	$2.60	$1.86	$1.25	$1.76
Diluted earnings (loss) per average share -					
Continuing operations	$2.89	$2.61	$2.01	$1.01	$1.62
Discontinued operations	—	(0.02)	(0.16)	0.23	0.14
Non-controlling interest	—	—	—	—	—
Total	$2.89	$2.59	$1.85	$1.24	$1.76
Dividends Declared per Share	$1.56	$1.52	$1.48	$1.46	$1.44
Book Value Per Share, End of Year	$30.77	$29.35	$27.84	$27.55	$28.02
Return on Average Common Stock Equity (full year)	9.6 %	8.8 %	6.7 %	4.3 %	6.3 %

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SELECTED FINANCIAL DATA continued

Years ended December 31,	2014	2013	2012	2011	2010
Operating Statistics:					
Generating capacity (MW):					
Electric Utilities (owned generation)	841	790	859	865	687
Electric Utilities (purchased capacity)	210	150	150	450	440
Power Generation (owned generation)	269	309	309	309	120
Total generating capacity	1,320	1,249	1,318	1,624	1,247
Electric Utilities:					
MWh sold:					
Retail electric	4,775,808	4,642,254	4,598,080	4,590,800	4,532,191
Contracted wholesale	340,871	357,193	340,036	349,520	468,782
Wholesale off-system	1,118,641	1,456,762	1,652,949	1,788,005	1,749,524
Total MWh sold	6,235,320	6,456,209	6,591,065	6,728,325	6,750,497
Gas Utilities: [5]					
Gas sold (Dth)	60,323,416	59,097,493	47,358,505	55,764,154	55,265,630
Transport volumes (Dth)	67,463,143	63,821,546	60,480,822	59,216,132	59,879,450
Power Generation Segment:					
MWh Sold	1,760,160	1,564,789	1,304,637	556,577	519,057
MWh Purchased	38,237	5,481	8,011	402	27,734
Oil and Gas Segment:					
Oil and gas production sold (MMcfe)	9,986	9,529	12,544	11,762	11,300
Oil and gas reserves (MMcfe) [1]	101,416	86,713	80,683	133,242	131,096
Coal Mining Segment:					
Tons of coal sold (thousands of tons) [6]	4,317	4,285	4,246	5,692	5,931
Coal reserves (thousands of tons)	208,231	212,595	232,265	256,170	261,860

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(1) 2013 includes $6.6 million after-tax expense relating to the settlement of interest rate swaps in conjunction with the prepayment of Black Hills Wyoming’s project financing and write-off of deferred financing costs. 2012 includes a non-cash after-tax ceiling test impairment charge to our crude oil and natural gas properties of $17 million offset by an after-tax gain on sale of $19 million related to our Williston Basin assets. Reserves reflect the sale of the Williston Basin assets (see Notes 12 and 21 of the Notes to the Consolidated Financial Statements of this Annual Report on Form 10-K).

(2) 2011 and 2010 include a $27 million and $9.9 million non-cash after-tax unrealized mark-to-market loss, respectively, related to certain interest rate swaps; while 2013 and 2012 include a $20 million and $1.2 million non-cash after-tax unrealized mark-to-market gain, respectively, related to certain interest rate swaps. 2013 also includes $7.6 million after-tax expense for a make-whole premium, write-off of deferred financing costs relating to the early redemption of our $250 million notes and interest expense on new debt, while 2012 includes an after-tax make-whole provision of $4.6 million for early redemption of our $225 million notes.

(3) Discontinued operations include post-closing adjustments and operations relating to our Energy Marketing segment in 2013, 2012, 2011 and 2010.

(4) During November 2011, we issued 4.4 million shares of common stock, which diluted our earnings per share in subsequent periods.

(5) Excludes Cheyenne Light.

(6) Tons of coal decreased in 2012 due to the expiration of an unprofitable train load-out contract.

For additional information on our business segments see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Item 7A, Quantitative and Qualitative Disclosures about Market Risk and Note 4 to the Consolidated Financial Statements in this Annual Report on Form 10-K.

ITEMS 7 & and 7A. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS AND QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are a customer-focused integrated energy company operating principally in the United States with two major business groups - Utilities and Non-regulated Energy. We report our business groups in the following financial segments:

Business Group	Financial Segment
Utilities	Electric Utilities
	Gas Utilities
Non-regulated Energy	Power Generation
	Coal Mining
	Oil and Gas

Overview: Our customer focus provides opportunities to expand our business by constructing additional rate base assets to serve our utility customers and expanding our non-regulated energy products and services to our wholesale customers.

The diversity of our energy operations reduces reliance on any single business segment to achieve our strategic objectives. Our emphasis on our utility business with diverse geography and fuel mix, combined with a conservative approach to our non-regulated energy operations, mitigates our overall corporate risk and enhances our ability to earn stronger returns for shareholders over the long-term. Our long-term strategy focuses on growing both our utility and non-regulated energy businesses, primarily by increasing our customer base and providing superior service.

Our objective is to be best-in-class relative to certain operational performance metrics, such as safety, power plant availability, electric and gas system reliability, efficiency, customer service and cost management. Our notable operational performance metrics for 2014 include:

- Our three electric utilities achieved 1st quartile reliability ranking with 74 customer minutes of outage time (SAIDI) in 2014 compared to industry averages (IEEE 2013 1st quartile is less than 85 minutes);
- Our JD Power Customer Satisfaction Survey indicated our Electric and Gas Utilities were favorable to our peers in the Midwest;
- Our power generation fleet achieved a forced outage factor of 2.7% for coal-fired plants, 2.8% for natural gas plants in 2014 and 0.1% for diesel plants, compared to an industry average* of 3.5%, 4.6% and 1.7%, respectively (*NERC GADS 2013 data);
- Our power generation fleet availability was 94% for coal-fired plants, 95% for gas-fired plants, 96% for diesel-fired plants and 99% for wind generation in 2014 while the industry averages^ were 90%, 90%, 96% and 96%, respectively (^NERC GADS Data Base, 2013 most recent industry information);
- Our safety TCIR of 2.0 compares well to an industry average of 2.8* and our DART rate of 1.1 compares to an industry average of 1.4+ (+ Most recent industry averages are 2012);
- Our OSHA TCIR rate during construction of our generating facilities is also significantly better than industry average with a TCIR rate of 2 during the construction of the Wygen III coal-fired plant compared to an industry average of 5.1 for coal-fired plants, 1.3 during the construction of the Pueblo Airport Generating Station natural-gas fired plant compared to an industry average of 4.4 for natural-gas fired plants, 0 during construction of the Busch Ranch wind farm compared to an industry average of 4.4 for wind construction and 0 during the construction of the Cheyenne Prairie Generating Station natural-gas fired plant compared to an industry average of 2.1 for fossil fuel electric power generation; and
- Our coal mine completed three years with favorable MSHA safety results compared to other mines located in the Powder River Basin and received an award from the State of Wyoming for five years without a lost time accident.

The electric utility industry is facing requirements to upgrade aging infrastructure, deploy smart grid technology and comply with new state and federal environmental regulations and renewable portfolio standards. Increased energy efficiency, and smart grid technologies suppress demand in many areas of the United States. These competing considerations present challenges to energy companies’ approach of balancing capital spending and obtaining satisfactory rate recovery on investments.

State regulatory commissions have lowered authorized returns and implemented other regulatory mechanisms for cost recovery due to the slow-growing economy and concerns that utility rate increases may further harm local economies. The average awarded return on equity for investor-owned utilities over the past year has been averaging around 10%. The average regulatory lag is less than 12 months, according to the Edison Electric Institute. Falling interest rates account for much of the lower rates of return, along with actions by state commissions to moderate rate increases during a period of economic recovery.

In our gas and electric utilities’ service territories, we will continue to work with regulators to ensure we meet our obligations to serve projected customer demand and to comply with environmental mandates by constructing the infrastructure necessary to provide safe, reliable energy. By maintaining our high customer service and reliability standards in a cost-efficient manner, our goal is to secure appropriate rate recovery that provides fair economic returns on our utility investments.

The proliferation of domestic crude oil and natural gas production from shale plays in recent years has provided the domestic market an abundant new supply of both commodities, which has decreased the dependence on foreign resources of these commodities. The increased worldwide supply of crude oil caused WTI prices to decline from June 2014 highs of over $105 per Bbl, to January 2015 lows in the mid-$40s per Bbl. Natural gas prices have fallen from NYMEX prices exceeding $8.00 per MMbtu in February 2014 to below $3.00 per MMbtu in January 2015. Crude oil and natural gas prices are very difficult to predict. We will continue to evaluate the economics for oil or gas projects and investments to exceed our cost of capital. We strive to maintain strong relationships with mineral owners, landowners and regulatory authorities. As prudent, we will continue to grow and develop our existing inventory of crude oil and natural gas reserves. We intend to focus our near-term efforts on proving up the substantial Mancos shale gas potential of our Piceance Basin properties. Given increased regulatory emphasis on wind and solar power resources and environmental regulations and legislation that will limit construction of new coal-fired power plants, we believe that natural gas will be the fuel of choice for power generation. Additional gas-fired peaking resources will also be required to provide critical back-up for renewable technologies.

Currently approximately 40% of electricity generated in the United States is from coal-fired power plants. It will take significant time and expense before this generation can be replaced with alternative technologies. As a result, coal-fired resources will remain a necessary component of the nation's electric supply for the foreseeable future. The current regulatory climate, combined with the EPA's proposed and expected GHG regulations, have limited construction of new conventional coal-fired power plants, but, if technologies such as carbon capture and sequestration become more proven and less expensive, they could provide for the long-term economic use of coal. We have investigated and will continue to investigate the possible deployment of these technologies at our mine site in Wyoming.

We have expertise in permitting, constructing and operating power generation facilities. These skills, combined with our understanding of electric resource planning and regulatory procedures, provide a significant opportunity for us to add long-term shareholder value. We intend to grow our non-regulated power generation business by continuing to focus on long-term contractual relationships with our affiliates and other load-serving utilities.

Key Elements of our Business Strategy

Provide stable long-term rates for customers and increase earnings by efficiently planning, constructing and operating rate-base power generation facilities needed to serve our electric utilities. Our Company began as a vertically-integrated electric utility. This business model remains a core strength and strategy today, as we invest in and operate efficient power generation resources to cost effectively transmit and distribute electricity to our customers. We strive to provide power at reasonable rates to our customers and earn competitive returns for our investors.

We have a competitive power production strategy focused on low cost construction and operation of our generating facilities. Access to our own coal and third-party natural gas reserves allows us to be competitive as a power generator. Low production costs can result from a variety of factors including low fuel costs, efficiency in converting fuel into energy and low per unit operation and maintenance costs. We leverage our mine-mouth coal-fired generating capacity which strengthens our position as a low-cost producer by eliminating fuel transportation costs which often represent the largest component of the delivered cost of coal for many other utilities. In addition, we typically operate our plants with high levels of availability, compared to industry benchmarks. We aggressively manage each of these factors with the goal of achieving low production costs.

Rate-base generation assets offer several advantages including:

- Since the generating assets are included in the utility rate base and reviewed and approved by government authorities, customer rates are more stable and predictable, and typically less expensive in the long run, than if the power was purchased from the open market through wholesale contracts that are re-priced over time;
- Regulators participate in a planning process where long-term investments are designed to match long-term energy demand;
- Investors are provided a long-term, reasonable, stable return on their investment; and
- The lower risk profile of rate based generation assets may enhance credit ratings which, in turn, can benefit both consumers and investors by lowering our cost of capital.

Our actions to provide power at reasonable rates to our customers was exemplified in our successful request to secure the construction financing riders in Wyoming and South Dakota during the construction of Cheyenne Prairie. These riders reduced the total cost of the plant ultimately passed along to our customers while we constructed this plant to accommodate growth and replace plants that were closed prematurely due to environmental regulations.

Provide stable long-term rates for customers and increase earnings by efficiently planning and implementing a cost of service gas program to serve our electric and natural gas utilities. To further enhance our vertically integrated utility business model, we are evaluating the implementation of a program supporting our natural gas and electric utilities that can provide longer-term rate stability for our customers by enhancing our current gas supply portfolio through the addition of utility or affiliate-owned gas production and reserves. In addition to providing our customers the benefits associated with more predictable long-term commodity prices, it also provides increased earnings opportunity for our shareholders. We are discussing the concept with state regulatory commissioners, staff and consumer advocates. Prior to proceeding, we will need to obtain regulatory approval from our state utility commissions for the program. Several utilities have cost of service gas programs in place in various states, including both Wyoming and Montana.

We have a competitive advantage related to cost of service gas in that our existing non-regulated oil and gas subsidiary could assist in drilling/acquiring and operating the gas reserves required to meet the needs of our electric and gas utilities.

Expand utility operations through selective acquisitions of electric and gas utilities consistent with our regional focus and strategic advantages. For more than 130 years we have provided reliable utility services, delivering quality and value to our customers. Utility operations contribute substantially to the stability of our long-term cash flows, earnings and dividend policy. Our tradition of accomplishment supports efforts to expand our utility operations into other markets, most likely in areas that permit us to take advantage of our intrinsic competitive advantages, such as baseload power generation, system reliability, superior customer service, community involvement and a relationship-based approach to regulatory matters. Utility operations also enhance other important business development opportunities, including gas transmission pipelines and storage infrastructure, which could promote other non-regulated energy operations.

We have and will continue to pursue the purchase of not only large utility properties, but also smaller, private or municipal utility systems, which can be easily integrated into our operations. We purchased several small natural gas distribution systems in Kansas, Iowa and Wyoming in the past several years. We have a scalable platform of systems and processes, which simplifies the integration of our utility acquisitions. Merger and acquisition activity has continued in the utility industry and we expect to consider such opportunities if they advance our long-term strategy and add shareholder value.

Build and maintain strong relationships with wholesale power customers of both our utilities and non-regulated power generation business. We strive to build strong relationships with other utilities, municipalities and wholesale customers. We believe we will continue to be a primary provider of electricity to wholesale utility customers, who will continue to need products, such as capacity, in order to reliably serve their customers. By providing these products under long-term contracts, we help our customers meet their energy needs. We also earn more stable revenues and greater returns over the long term than we could by selling energy into more volatile spot markets. In addition, relationships that we have established with wholesale power customers have developed into other opportunities. MEAN, MDU and the City of Gillette, Wyoming were wholesale power customers that are now joint owners in two of our power plants, Wygen I and Wygen III.

Proactively integrate alternative and renewable energy into our utility energy supply while mitigating and remaining mindful of customer rate impacts. The energy and utility industries face tremendous uncertainty related to the potential impact of legislation and regulation intended to reduce GHG emissions and increase the use of renewable and other alternative energy sources. To date, many states have enacted and others are considering some form of mandatory renewable energy standard, requiring utilities to meet certain thresholds of renewable energy generation. Some states have either enacted or are considering legislation setting GHG emissions reduction targets. Federal legislation for both renewable energy standards and GHG emission reductions is also under consideration.

Mandates for the use of renewable energy or the reduction of GHG emissions will likely produce substantial increases in the prices for electricity and natural gas. At the same time, as a regulated utility we are responsible for providing safe, reasonably priced, reliable sources of energy to our customers. As a result, we employ a customer-centered strategy for complying with renewable energy standards and GHG emission regulations that balances our customers' rate concerns with environmental considerations and administrative and legislative mandates. We attempt to strike this balance by prudently and proactively incorporating renewable energy into our resource supply, while seeking to minimize the magnitude and frequency of rate increases for our utility customers.

- Colorado legislative mandates apply to our electric utility segment regarding the use of renewable energy. Therefore, we pursue cost-effective initiatives that allow us to meet our renewable energy requirements. Where permitted, we seek to construct renewable generation resources as rate base assets, which helps mitigate the long-term customer rate impact of adding renewable energy supplies. For example, the Busch Ranch Wind site, a 29 MW wind turbine project, was completed in the fourth quarter of 2012, as part of our plan to meet Colorado's Renewable Energy Standard. This site also has expansion potential;

- In states such as South Dakota and Wyoming that currently have no legislative mandate on the use of renewable energy, we have proactively integrated cost-effective renewable energy into our generation supply based upon our expectation that there will be mandatory renewable energy standards in the future. For example, under two 20-year PPAs we purchase a total of 60 MW of wind energy from wind farms located near Cheyenne, Wyoming for use at Black Hills Power and Cheyenne Light; and

- In all states in which we conduct electric utility operations, we are exploring other cost-effective potential biomass, solar and wind energy projects, particularly wind generation sites located near our utility service territories.

Increase the value of our oil and gas properties by prudently growing our reserves and increasing our production of natural gas and crude oil. Our strategy is to cost-effectively grow our reserves and increase our production of natural gas and crude oil through both organic growth and acquisitions. While consistent growth remains our objective, we emphasize managing for value creation over managing for growth as follows:

- Perform detailed reservoir analysis and apply proven technologies to our existing assets to maximize value;
- Participate in a limited number of selective and meaningful exploration prospects;
- Focus primarily on the Rocky Mountain region, where we can more easily integrate new opportunities with our existing crude oil and natural gas operations as well as our power generation activities. Specifically, we intend to focus our near term efforts on fully developing the substantial shale gas potential of our San Juan and Piceance Basin properties and participating in select oil exploration prospects with substantial upside opportunities;
- Support the future capital requirements of our drilling program by stabilizing cash flows with a hedging program that mitigates commodity price risk for up to three years of future production; and
- Enhance our crude oil and natural gas production activities with the construction or acquisition of mid-stream gathering, compression and treating facilities in a manner that maximizes the economic value of our operations.

Selectively grow our non-regulated power generation business in targeted regional markets by developing assets and selling most of the capacity and energy production through mid- and long-term contracts primarily to load-serving utilities. While much of our recent power plant development has been for our regulated utilities, we seek to expand our non-regulated power generation business by developing and operating power plants in regional markets based on prevailing supply and demand fundamentals, in a manner that complements our existing fuel assets and marketing capabilities. We seek to grow this business through the development of new power generation facilities and disciplined acquisitions primarily in the western region, where we believe our detailed knowledge of market and electric transmission fundamentals provides us a competitive advantage and, consequently, increases our ability to earn attractive returns. We prioritize small-scale facilities that serve incremental growth or provide critical back up to renewable resources and are typically easier to permit and construct than large-scale generation projects.

Most of the energy and capacity from our non-regulated power facilities is sold under mid- and long-term contracts. When possible, we structure long-term contracts as tolling arrangements, whereby the contract counterparty assumes the fuel risk. Going forward, we will continue to focus on selling a majority of our non-regulated capacity and energy primarily to load-serving utilities under long-term agreements that have been reviewed or approved by state utility commissions. An example of this strategy is the 200 MW of combined-cycle gas-fired generation constructed by our non-regulated power generation subsidiary to serve our Colorado Electric utility subsidiary. The plant commenced operations on January 1, 2012, under a 20-year tolling agreement.

Diligently manage the credit, price and operational risks inherent in buying and selling energy commodities. All of our operations require effective management of counterparty credit risk. We mitigate this risk by conducting business with a diverse group of creditworthy counterparties. In certain cases where creditworthiness merits security, we require prepayment, secured letters of credit or other forms of financial collateral. We establish counterparty credit limits and employ continuous credit monitoring, with regular review of compliance under our credit policy by our Executive Risk Committee. Our oil and gas and power generation operations require effective management of price and operational risks related to adverse changes in commodity prices and the volatility and liquidity of the commodity markets. To mitigate these risks, we implemented risk management policies and procedures. Our oversight committees monitor compliance with these policies.

Maintain an investment grade credit rating and ready access to debt and equity capital markets. Access to capital has been and will continue to be critical to our success. We have demonstrated our ability to access the debt and equity markets, resulting in sufficient liquidity. We require access to the capital markets to fund our planned capital investments or acquire strategic assets that support prudent business growth. Our access to adequate and cost-effective financing depends upon our ability to maintain our investment-grade issuer credit rating.

Moody's and Fitch each upgraded our corporate credit rating during 2014, which enhanced our capacity to extend our revolving credit facility, and place permanent financing for Cheyenne Prairie through the sale of $160 million of first mortgage bonds in a private placement at favorable terms.

Prospective Information

We expect to generate long-term growth through the expansion of integrated and diverse energy operations. Sustained growth requires continued capital deployment. Our diversified energy portfolio with an emphasis on regulated utilities provides growth opportunities, yet avoids concentrating business risk. We expect much of our growth in the next few years will come from major capital investments at our existing business segments. During 2014, we put permanent financing in place for Cheyenne Prairie and during 2013, we refinanced much of our highest cost debt on favorable terms. Although dependent on market conditions, we are confident in our ability to obtain additional financing, as necessary, to continue our growth plans. We remain focused on prudently managing our operations and maintaining our overall liquidity to meet our operating, capital and financing needs, as well as executing our long-term strategic plan.

Utilities Group

Electric Utilities

On October 1, 2014, Black Hills Power and Cheyenne Light placed into commercial service their jointly-owned Cheyenne Prairie generating station, a 132 MW generating facility located in Cheyenne, Wyoming. Cheyenne Prairie was constructed on time and on budget. Black Hills Power and Cheyenne Light sold $160 million of first mortgage bonds in a private placement to provide permanent financing for Cheyenne Prairie. Cheyenne Light and Black Hills Power received approval for increased rates in Wyoming effective October 1, 2014. Black Hills Power also implemented interim rates in South Dakota on October 1, 2014. Hearings for the South Dakota rate case were held on January 27-28, 2015 and the commission’s final decision is expected in first quarter 2015.

Residential MWh sold decreased in 2014 due to milder weather resulting from lower cooling degree days. Industrial loads increased primarily at Cheyenne Light and Colorado Electric. Cheyenne Light recorded an all-time peak load of 198 MW in July 2014.

BHC continued its efforts to acquire smaller public and municipal gas distribution systems adjacent to our existing service territories. On October 14, 2014, we announced an agreement to acquire Energy West Wyoming, Inc., a Wyoming gas utility, and pipeline assets of Gas Natural, Inc. for $17 million. The gas utility serves approximately 6,700 customers, including service to Cody, Ralston and Meeteetse, Wyoming. The pipeline assets include a 30 mile gas transmission pipeline and a 42 mile gas gathering pipeline, both located near the utility service territory. In January 2015, Cheyenne Light also closed on the acquisition of assets serving approximately 400 customers in northeast Wyoming.

Cheyenne Light received FERC approval to establish rates for transmission services under their Open Access Transmission Tariff, effective May 3, 2014.

Colorado Electric received a final order from the CPUC approving a CPCN for the retirement of Pueblo Units #5 and #6, effective December 31, 2013.

Pursuant to prior approved resource plans and pending electric rate increase requests, the Electric Utilities engaged in the following regulatory requests related to construction activities:

- On July 22, 2014, Black Hills Power filed a CPCN with the WPSC to construct the Wyoming portion of a $54 million, 230-kV, 144 mile-long transmission line that would connect the Teckla Substation in northeast Wyoming, to the Lange Substation near Rapid City, South Dakota. Approval by the WPSC is anticipated in the second quarter of 2015. Black Hills Power has received approval from the SDPUC for a permit to construct the line.

- On May 5, Colorado Electric issued an all-source generation request, including up to 60 megawatts of eligible renewable energy resources to serve its customers in southern Colorado. Our power generation segment submitted solar and wind bids in response to the request. On December 23, 2014 the independent evaluator submitted a report to the Colorado Public Utilities Commission confirming the ranking of the bids. The report's results indicate that our standalone bids were not among the highest ranked bids. However, two of the highest ranked bids provide an opportunity for Colorado Electric or our power generation segment to be partial or full owners of the facilities. At its deliberation in February 2015, the Commission determined none of the alternatives was acceptable, because of potential short-term rate impacts. The Commission discussed the possibility that Colorado Electric could more economically comply with the renewable energy standard by purchasing renewable energy credits. The purchase of renewable energy credits will be considered in a separate proceeding. After review of the Commission's decision regarding the all source solicitation (which has not yet been issued), Colorado Electric will determine whether to seek reconsideration.

- On December 19, 2014, Colorado Electric received approval from the CPUC for an annual electric revenue increase of $3.1 million with a return on equity of 9.83% and a capital structure of 49.83% equity and 50.17% debt. The CPUC also authorized the implementation of a rider for a return on capital expenditures for a $65 million natural gas-fired combustion turbine that will replace the retired W.N. Clark power plant.

Gas Utilities

Weather was colder than normal in the first quarter of 2014, which drove an increase in natural gas sales. Our Gas Utilities invested in our gas distribution network and related technology such as advanced metering infrastructure and mobile data terminals. We continually monitor our investments and costs of operations in all states to determine the appropriateness of additional rate case or other rate filings. As part of our growth strategy, we continue to look for opportunities to purchase municipal and privately-owned gas infrastructure and distribution systems. We acquired a small gas system during 2014 with a total of approximately 70 customers.

Non-regulated Energy Group

Power Generation

Black Hills Wyoming closed the sale of its 40 MW CTII natural gas-fired generating unit to the City of Gillette for approximately $22 million, upon expiration of the PPA with Cheyenne Light in August 2014. As part of the sale, Black Hills Wyoming will provide services to the City of Gillette through an economy energy PPA. We recognized approximately $0.5 million of margin under the new economy PPA, which became effective in September 2014. We plan to continue evaluating opportunities to bid on the construction of generation resources, both new and existing, for our affiliate electric utilities and other regional electric utilities for their energy and capacity needs.

Coal Mining

Production from the Coal Mining segment primarily serves mine-mouth generation plants and select regional customers with long-term fuel needs. Total annual production was approximately 4.3 million tons for 2014, which was consistent with 2013. Mining operations moved to an area with lower overburden ratios in 2013, which reduced mining costs, but in 2014, our overburden ratios increased as we mined areas with a higher stripping ratio. Stripping ratios are expected to increase again in 2015 to approximately 1.5 as the areas planned for mining contain higher overburden.

Our strategy is to sell the majority of our coal production to on-site, mine-mouth generation facilities under long-term supply contracts. Historically our off-site sales have been to consumers within a close proximity to our mine, including off-site sales contracts served by truck. In January 2014, we received State of Wyoming permit approval for Black Hills Power to acquire a stock pile of approximately 75,000 tons of coal near the mine mouth power plants to ensure adequate emergency back-up of coal supply. We continue to pursue new opportunities to market our coal despite limitations inherent to transporting our lower-heat content coal.

Oil and Gas

During 2014, BHEP continued to prove up the value of our existing properties, primarily our Mancos formation shale gas assets in the Piceance and San Juan Basins, while conserving capital and strictly controlling costs. After drilling and completing two Mancos formation exploration wells in the southern Piceance Basin and one exploration well in the San Juan Basin in 2011, the appraisal program was deferred in 2012 due to low natural gas prices. The program continued in 2013 with the drilling of two additional Piceance wells. Three more Piceance wells were drilled in 2014, which will be placed on production during the first quarter of 2015. We plan to continue our efforts in 2015 to prove up the value of our oil and gas properties.

Corporate

Our consolidated interest expense decreased in 2014, primarily due to the refinancing of higher cost debt in 2013 as well as upgrades to our corporate credit ratings by S&P, Moody's and Fitch during 2014 and 2013. We executed a 10-year $525 million note offering in November 2013 at an interest rate of 4.25%, which we used to repay higher cost debt and settle interest rate swaps. Our interest expense was unfavorably impacted in 2013 by costs related to early retirement of $250 million senior unsecured notes due in 2014 and the settlement of interest rate swaps.

A portion of the proceeds from the $525 million notes in late 2013 were used for the termination of the de-designated interest rate swaps, which did not qualify for "hedge accounting" treatment provided by accounting standards for derivatives and hedges. With the termination of these swaps, our income statement will no longer reflect the volatility associated with fluctuations in the fair value of these swaps caused by interest rate changes.

Results of Operations

Executive Summary and Overview

	For the Years Ended December 31,				
	2014	Variance	2013	Variance	2012
	(in thousands)				
Revenue					
Utilities	$1,315,079	$110,082	$1,204,997	$123,950	$1,081,047
Non-regulated Energy	206,030	11,481	194,549	(21,690)	216,239
Inter-company eliminations	(127,539)	(3,845)	(123,694)	(292)	(123,402)
	$1,393,570	$117,718	$1,275,852	$101,968	$1,173,884
Income (loss) from continuing operations					
Electric Utilities	$59,552	$7,418	$52,134	$536	$51,598
Gas Utilities	41,869	9,162	32,707	4,717	27,990
Utilities	101,421	16,580	84,841	5,253	79,588
Power Generation [(a)]	28,516	12,228	16,288	(5,040)	21,328
Coal Mining	10,452	4,125	6,327	701	5,626
Oil and Gas[(b)]	(10,633)	(6,421)	(4,212)	(1,983)	(2,229)
Non-regulated Energy	28,335	9,932	18,403	(6,322)	24,725
Corporate and Eliminations[(c)(d)(e)]	(975)	(13,577)	12,602	28,410	(15,808)
Income from continuing operations	128,781	12,935	115,846	27,341	88,505
Income (loss) from discontinued operations, net of tax[(f)]	—	884	(884)	6,093	(6,977)
Net income (loss)	$128,781	$13,819	$114,962	$33,434	$81,528

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(a) Income (loss) from continuing operations in 2013 includes a $6.6 million after-tax expense relating to the settlement of interest rate swaps in conjunction with the prepayment of Black Hills Wyoming’s project financing and write-off of deferred financing costs.

(b) Income (loss) from continuing operations in 2012 includes a $17 million non-cash after-tax ceiling test impairment loss and a $19 million after-tax gain on sale of our Williston Basin assets. See Notes 12 and 21 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

(c) Financial results of Enserco, our Energy Marketing segment, have been reclassified as discontinued operations in accordance with GAAP. When preparing this reclassification, certain indirect corporate costs and inter-segment interest expenses previously charged to our Energy Marketing segment could not be reclassified to discontinued operations of $0.6 million for 2012 and accordingly have been presented within Corporate. See Note 21 of the Consolidated Financial Statements in this Annual Report on Form 10-K.

(d) 2013 includes a $7.6 million after-tax make-whole premium and write-off of deferred financing costs relating to the early redemption of our $250 million notes and interest expense on new debt, while 2012 includes a $4.6 million after-tax make-whole premium for the early redemption of our $225 million notes and a $1.0 million write-off of deferred financing costs relating to early renewal of our Revolving Credit Facility.

(e) 2013 and 2012 include a $20 million and a $1.2 million non-cash after-tax mark-to-market gain, respectively, related to certain interest rate swaps.

(f)

Income (loss) from discontinued operations, net of tax includes the activities of Enserco, our Energy Marketing segment. See Note 21 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

On February 29, 2012, we sold our Energy Marketing segment, which resulted in this segment being classified as discontinued operations. Additionally, the following business group and segment information does not include inter-company eliminations and all amounts are presented on a pre-tax basis unless otherwise indicated. Per share information references diluted shares unless otherwise noted.

2014 Compared to 2013

Income from continuing operations was $129 million, or $2.89 per share, in 2014 compared to $116 million, or $2.61 per share, in 2013. The 2014 Income from continuing operations did not include any expenses, gains, or losses that we believe are not representative of our core operating performance. The 2013 Income from continuing operations includes a $20 million non-cash after-tax mark-to-market gain on certain interest rate swaps, $6.6 million after-tax interest expense related to the early settlement of interest rate swaps and write-off of deferred financing costs associated with the prepayment of Black Hills Wyoming's project financing and $7.6 million after-tax expense for a make-whole premium and write-off of deferred financing costs relating to the early redemption of our $250 million notes.

Net income was $129 million, or $2.89 per share, in 2014 compared to $115 million, or $2.59 per share, in 2013 and includes the same items described above and losses from our Energy Marketing segment sold in February 2012.

Business Group highlights for 2014 include:

Utilities Group

Highlights of the Utilities Group include the following:

- Gas Utilities were favorably impacted by colder than normal weather during the first quarter of 2014, which was 14% colder than normal and 7% colder than the first quarter of 2013. This led to an increase in retail natural gas sold and offset unfavorable weather experienced through the remainder of 2014 when compared to 2013. Our service territories reported colder than normal winter weather as measured by heating degree days, compared to the 30-year average, but not as cold as 2013. Heating degree days for the full year in 2014 were 7% colder than normal but 2% less than the same period in 2013.

- Mild weather was a contributing factor for our Electric Utilities during the year. Weather related demand during the peak summer months was tempered by significantly cooler temperatures within our service territories. Cooling degree days for the full year of 2014 were 29% lower than the same period in the prior year and 12% lower than normal.

- On December 19, 2014, Colorado Electric received approval from the CPUC for an annual electric revenue increase of $3.1 million. The approval also allowed a 9.83% return on equity and a capital structure of 49.83% equity and 50.17% debt. The CPUC also authorized the implementation of a rider for a return on capital expenditures for a $65 million natural gas-fired combustion turbine that will replace the retired W.N. Clark power plant.

- On December 16, Kansas Gas received approval from the Kansas Corporation Commission to increase annual base revenue by an estimated $5.2 million, effective Jan. 1, 2015.

- On October 1, 2014, Black Hills Power and Cheyenne Light placed into commercial service their jointly-owned Cheyenne Prairie generating station. Cheyenne Prairie is a 132 MW, $222 million natural gas-fired generating facility built to serve Black Hills Power and Cheyenne Light customers. Cheyenne Prairie was constructed on time and on budget. Construction financing costs were recovered through construction financing riders.

On October 1, 2014, Black Hills Power and Cheyenne Light sold $160 million of first mortgage bonds in a private placement to provide permanent financing for Cheyenne Prairie. Black Hills Power issued $85 million of 4.43% coupon first mortgage bonds due October 20, 2044 and Cheyenne Light issued $75 million of 4.53% coupon first mortgage bonds due October 20, 2044. Proceeds from Black Hills Power's bond sale also funded the early redemption of its 5.35%, $12 million pollution control revenue bonds, originally due October 1, 2024.

Black Hills Power and Cheyenne Light each received approval from the WPSC on rate cases associated with Cheyenne Prairie. On August 21, 2014, the WPSC approved rate case settlement agreements authorizing an increase for Black Hills Power of approximately $2.2 million for annual electric revenue, effective October 1, 2014. The settlement also included a return on equity of 9.9% and a capital structure of 53.3% equity and 46.7% debt. On July 31, 2014, the WPSC approved rate case settlement agreements authorizing an increase for Cheyenne Light of $8.4 million and $0.8 million for annual electric and natural gas revenue, respectively, effective October 1, 2014. The settlement also included a return on equity of 9.9% and a capital structure of 54% equity and 46% debt.

On March 31, 2014, Black Hills Power filed a rate request with the SDPUC to increase annual revenue by $14.6 million to recover operating expenses and infrastructure investments, primarily for Cheyenne Prairie. The filing seeks a return on equity of 10.25% and a capital structure of approximately 53.3% equity and 46.7% debt. Interim rates were implemented on October 1, 2014 when Cheyenne Prairie commenced commercial operations. A final ruling from the SDPUC is expected in the first quarter of 2015.

- On July 22, 2014, Black Hills Power filed a CPCN with the WPSC to construct the Wyoming portion of a $54 million, 230-kV, 144 mile-long transmission line that would connect the Teckla Substation in northeast Wyoming, to the Lange Substation near Rapid City, South Dakota. Approval by the WPSC is anticipated in the second quarter of 2015.
On June 30, 2014, Black Hills Power filed an application with the SDPUC, for a permit to construct the South Dakota portion of this line, and received approval on November 6, 2014.

- On May 5, 2014, Colorado Electric issued an all-source generation request, including up to 60 megawatts of eligible renewable energy resources to serve its customers in southern Colorado. Our power generation segment submitted solar and wind bids in response to the request. On December 23, 2014 the independent evaluator submitted a report to the Colorado Public Utilities Commission confirming the ranking of the bids. The report's results indicate that our standalone bids were not among the highest ranked bids. However, two of the highest ranked bids provide an opportunity for Colorado Electric or our power generation segment to be partial or full owners of the facilities. At its deliberation in February 2015, the Commission determined none of the alternatives was acceptable, because of potential short-term rate impacts. The Commission discussed the possibility that Colorado Electric could more economically comply with the renewable energy standard by purchasing renewable energy credits. The purchase of renewable energy credits will be considered in a separate proceeding. After review of the Commission's decision regarding the all source solicitation (which has not yet been issued), Colorado Electric will determine whether to seek reconsideration.

- On April 25, 2014, Cheyenne Light received FERC approval to establish rates for transmission services under their Open Access Transmission Tariff, effective May 3, 2014. The approval includes a return on equity of 10.6% and a capital structure of 54% equity and 46% debt.

- On March 21, 2014, Black Hills Power retired the Ben French, Neil Simpson I and Osage coal-fired power plants. These three plants totaling 81 MW were closed because of federal environmental regulations. These plants were largely replaced by Black Hills Power's share of Cheyenne Prairie.

- On February 25, 2014, the CPUC issued a final order after rehearing, approving a CPCN for the retirement of Pueblo Unit #5 and #6, effective December 31, 2013.

- BHC continued its efforts to acquire smaller public and municipal gas distribution systems adjacent to our existing service territories.

On January 1, 2015, we closed a $6 million transaction to acquire the natural gas utility assets of MGTC, Inc., a northeast Wyoming system serving more than 400 customers. This system will be operated by and consolidated into the results of Cheyenne Light.

On October 14, 2014, we announced an agreement to acquire Energy West Wyoming, Inc., a Wyoming gas utility, and pipeline assets of Gas Natural, Inc. for $17 million. The gas utility serves approximately 6,700 customers, including service to Cody, Ralston and Meeteetse, Wyoming. The pipeline assets include a 30 mile gas transmission pipeline and a 42 mile gas gathering pipeline, both located near the utility service territory.

During the first quarter of 2014, we acquired an additional gas system in Kansas, adding approximately 70 customers.

Non-regulated Energy Group

- Coal Mining completed negotiations on the coal contract price increase with the third-party operator of the Wyodak plant. The new coal price of $18.25 per ton, an increase of approximately $4.75, was effective July 1, 2014.

- On September 3, 2014, Black Hills Wyoming closed the sale of its 40 MW CTII natural-gas fired generating unit to the City of Gillette, Wyoming for approximately $22 million, upon expiration on August 31, 2014 of the PPA with Cheyenne Light. As part of the sale, Black Hills Wyoming will provide services to the City of Gillette through ancillary agreements, including an operating agreement and an economy energy PPA. The sale resulted in a deferred gain of $4.9 million which Black Hills Wyoming will recognize equally over the twenty-year term of the operating agreement.

- Our southern Piceance Basin drilling program continued in 2014. During the third quarter, three Mancos Shale wells were drilled, cased and cemented. On March 6, 2014, the Summit Midstream cryogenic gas processing plant with a capacity of 20,000 Mcf per day started serving the company's gas production in the southern Piceance Basin, including two Mancos Shale wells placed on production during the first quarter.

Corporate Activities

- The company recently announced that Anthony Cleberg, executive vice president and chief financial officer, will retire at the end of March 2015. Richard Kinzley, previously vice president and controller and a 15-year veteran of the company, was appointed senior vice president and chief financial officer, effective January 1, 2015. In addition, the senior leadership team was expanded when Brian Iverson, previously vice president and treasurer and 11-year veteran of the company, was appointed senior vice president regulatory and government affairs and assistant general counsel.

- Consolidated interest expense decreased by approximately $41 million in 2014, compared to 2013, due primarily to the refinancing activities occurring during the fourth quarter of 2013 and the extension of our Revolving Credit Facility under favorable terms on May 29, 2014.

- On June 13, 2014, Fitch upgraded the BHC credit rating to BBB+ with a stable outlook.

- On May 29, 2014, we amended our $500 million corporate Revolving Credit Facility agreement to extend the term through May 29, 2019. This facility is substantially similar to the former agreement, which includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents, to increase the capacity of the facility to $750 million. Borrowings continue to be available under a base rate or various Eurodollar rate options for which the borrowing rates were reduced under the amended agreement.

- On January 30, 2014, Moody's upgraded the BHC credit rating to Baa1 from Baa2 with a stable outlook.

2013 Compared to 2012

Income from continuing operations was $116 million, or $2.61 per share, in 2013 compared to $89 million, or $2.01 per share, in 2012. The 2013 Income from continuing operations includes a $20 million non-cash after-tax mark-to-market gain on certain interest rate swaps, $6.6 million after-tax interest expense related to the early settlement of interest rate swaps and write-off of deferred financing costs associated with the prepayment of Black Hills Wyoming's project financing and $7.6 million after-tax expense for a make-whole premium and write-off of deferred financing costs relating to the early redemption of our $250 million notes and interest expense on new debt. The 2012 Income from continuing operations includes a $19 million after-tax gain on sale related to the Williston Basin asset sale, a $17 million non-cash after-tax ceiling test impairment, a $1.0 million non-cash after-tax write-off of deferred financing costs related to our previous Revolving Credit Facility, a $4.6 million after-tax make-whole premium for the early redemption of our $225 million corporate notes and a $1.2 million non-cash after-tax mark-to-market gain on certain interest rate swaps.

Net income was $115 million, or $2.59 per share, in 2013 compared to $82 million, or $1.85 per share, in 2012 and includes the same items described above and losses from our Energy Marketing segment sold in February 2012.

Business Group highlights for 2013 included:

Utilities Group

Highlights of the Utilities Group include the following:

- On September 17, 2013, the South Dakota Public Utilities Commission approved a general rate case settlement agreement authorizing an increase for Black Hills Power of $8.8 million, or 6.4%, in annual electric revenues effective June 16, 2013. The settlement agreement was confidential and certain terms were not disclosed.

- On September 17, 2013, the SDPUC approved the construction financing rider in lieu of traditional AFUDC with an effective date of April 1, 2013. The rider allowed Black Hills Power to earn and collect a rate of return during the construction period on its approximately 40% share of the total Cheyenne Prairie project cost that relates to South Dakota customers, while also saving customers money over the long-term. Cheyenne Light and Black Hills Power received approval from the WPSC for a similar construction financing rider in 2012 which allowed Cheyenne Light and Black Hills Power to earn and collect a rate of return during the construction period on approximately a 60% share of the project costs related to serving Wyoming customers, while also lowering the overall cost of the project to customers.

- Utility results for 2013 were favorably impacted by cold weather while 2012 utility results were unfavorably impacted by warm weather, particularly at the Gas Utilities. Our service territories reported colder winter weather, as measured by heating degree days, compared to the 30-year average and the prior year. Heating degree days for the full year in 2013 were 9% higher than weighted average norms for our Gas Utilities and 25% higher than the same period in 2012.

- During 2013, Cheyenne Light and Black Hills Power commenced construction on Cheyenne Prairie. Project costs for plant construction and associated transmission were estimated at $222 million, of which approximately $156 million was spent as of December 31, 2013.

- In April 2013, Colorado Electric filed an Energy Resource Plan with the CPUC addressing its projected resource requirements through 2019. The resource plan identified a 40 MW, simple-cycle, natural gas-fired turbine as the replacement of W.N. Clark. On January 6, 2014, the CPUC issued its initial written decision approving construction of the turbine.

- On April 15, 2013, the IUB approved a Capital Infrastructure Automatic Adjustment Mechanism effective April 25, 2013, for $0.2 million. This adjustment mechanism requires an annual filing, therefore, subsequent filings will vary in size based on eligible infrastructure replacements and the timing of future general rate case filings.

- On November 25, 2013, the NPSC approved an Infrastructure System Replacement Cost Recovery Charge that provided for an annual revenue increase of $1.4 million.

- On December 31, 2013, Colorado Electric retired W.N. Clark and Pueblo Units #5 and #6. These facilities, and certain Black Hills Power generating facilities, are being permanently retired primarily due to state and federal environmental regulations. The affected plants are listed in the table below with their operations suspension date and their ultimate retirement date:

Plant	Company	MW	Type of Plant	Date Suspended	Actual Retirement Date	Age of Plant (in years)
Osage	Black Hills Power	34.5	Coal	October 1, 2010	March 21, 2014	64

Ben French	Black Hills Power	25.0	Coal	August 31, 2012	March 21, 2014	52
Neil Simpson I	Black Hills Power	21.8	Coal	NA	March 21, 2014	43
W.N. Clark	Colorado Electric	42.0	Coal	December 31, 2012	December 31, 2013	57
Pueblo Unit #5	Colorado Electric	9.0	Gas	December 31, 2012	December 31, 2013	71
Pueblo Unit #6	Colorado Electric	20.0	Gas	December 31, 2012	December 31, 2013	63
	Total MW	152.3				

- Gas Utilities continued efforts to acquire small gas distribution systems adjacent to their existing gas utility service territories. During 2013, five small gas systems with a total of approximately 900 customers were acquired.

Non-regulated Energy Group

Highlights of the Non-regulated Energy Group include the following:

- In 2013, our Oil and Gas segment drilled and completed two horizontal wells in the Mancos Shale formation in the Piceance Basin. These wells are part of a transaction in which we earned approximately 20,000 net acres of Mancos Shale leasehold in the Piceance Basin in exchange for drilling and completing the two wells.

- Black Hills Wyoming entered into an agreement to sell its 40 MW CTII natural-gas fired generating unit to the City of Gillette for approximately $22 million upon expiration on August 31, 2014 of the PPA with Cheyenne Light. As part of the sale, Black Hills Wyoming will provide services to the City of Gillette through ancillary agreements, including a 20-year operating agreement and a 20 year economy energy PPA. The sale closed in September 2014.

- On September 27, 2012, our Oil and Gas segment sold approximately 85% of its Williston Basin assets, including approximately 73 gross wells and 28,000 net leasehold acres, for net cash proceeds of approximately $228 million. We recognized a gain of $29 million on the sale. The portion of the sale amount not recognized as gain reduced the full-cost pool and had the effect of reducing the depreciation, depletion and amortization rate after the sale.

- Coal Mining continued operations under its revised mine plan. Mining operations moved in August 2012, to an area with lower overburden ratios, which reduced mining costs in 2013.

- In the second quarter of 2012, our Oil and Gas segment recorded a $27 million non-cash ceiling test impairment loss as a result of continued low natural gas prices.

Corporate

Activities at Corporate include the following:

- On November 19, 2013, we completed a public debt offering of $525 million in senior unsecured debt at 4.25% due November 30, 2023. Proceeds were used to redeem our $250 million, 9% senior unsecured notes, pay off the Black Hills Wyoming project financing and related interest rate swaps, settle the de-designated interest rate swaps, partially pay down our Revolving Credit Facility and the remainder was used for other corporate purposes.

- On September 25, 2013, Moody’s raised our corporate credit rating to Baa2 from Baa3 with continued positive outlook. On July 24, 2013, S&P raised our corporate credit rating to BBB from BBB- with a stable outlook. They also raised our senior unsecured rating to BBB from BBB-. On May 10, 2013, Fitch Ratings raised our Issuer Default Rating to BBB from BBB- with a positive outlook. Subsequently on January 30, 2014, Moody’s upgraded our corporate credit rating to Baa1 and changed their outlook to stable.

- On June 21, 2013, we replaced our $150 million and $100 million term loans with a two-year term loan for $275 million at an interest rate of 1.125% over LIBOR.

- We recognized a non-cash unrealized mark-to-market gain related to certain interest rate swaps of $30 million in 2013 compared to a $1.9 million unrealized mark-to-market loss on these swaps in 2012. These swaps were settled in November 2013.

Operating Results

A discussion of operating results from our business segments follows.

All amounts are presented on a pre-tax basis unless otherwise indicated.

Utilities Group

Non-GAAP Financial Measure

The following discussion includes financial information prepared in accordance with GAAP, as well as another financial measure, gross margin, that is considered a "non-GAAP financial measure." Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. Gross margin (revenue less cost of sales) is a non-GAAP financial measure due to the exclusion of depreciation from the measure. The presentation of gross margin is intended to supplement investors' understanding of our operating performance.

In our Management Discussion and Analysis of Results of Operations, gross margin for our Electric Utilities is calculated as operating revenue less cost of fuel, purchased power and cost of gas sold. Gross margin for our Gas Utilities is calculated as operating revenues less cost of gas sold. Our gross margin is impacted by the fluctuations in power purchases and natural gas and other fuel supply costs. However, while these fluctuating costs impact gross margin as a percentage of revenue, they only impact total gross margin if the costs cannot be passed through to our customers.

Our gross margin measure may not be comparable to other companies' gross margin measure. Furthermore, this measure is not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

Electric Utilities

Operating results for the years ended December 31 for the Electric Utilities were as follows (in thousands):

	2014	Variance	2013	Variance	2012
Revenue - electric	$657,556	$29,511	$628,045	$32,503	$595,542
Revenue - Cheyenne Light gas	39,754	2,491	37,263	5,839	31,424
Total revenue	697,310	32,002	665,308	38,342	626,966
Fuel and purchased power - electric	291,645	16,682	274,963	17,921	257,042
Purchased gas - Cheyenne Light	22,928	3,843	19,085	2,653	16,432
Total fuel and purchased power	314,573	20,525	294,048	20,574	273,474
Gross margin - electric	365,911	12,829	353,082	14,582	338,500
Gross margin - Cheyenne Light gas	16,826	(1,352)	18,178	3,186	14,992
Total gross margin	382,737	11,477	371,260	17,768	353,492
Operations and maintenance	165,640	5,679	159,961	13,434	146,527
Depreciation and amortization	79,424	1,720	77,704	2,460	75,244
Total operating expenses	245,064	7,399	237,665	15,894	221,771
Operating income	137,673	4,078	133,595	1,874	131,721
Interest expense, net	(48,787)	7,473	(56,260)	(5,219)	(51,041)
Other income, net	1,164	531	633	(549)	1,182
Income tax expense	(30,498)	(4,664)	(25,834)	4,430	(30,264)

Income from continuing operations	$59,552	$7,418	$52,134	$536	$51,598

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	2014	2013	2012
Regulated power plant fleet availability:			
Coal-fired plants [(a)]	93.8%	96.7%	90.8%
Other plants [(b)]	90.2%	96.5%	96.9%
Total availability	91.5%	96.6%	93.9%

(a) 2014 reflects a planned overhaul on Neil Simpson II for emissions controls upgrades.
(b) 2014 reflects planned overhauls for control system upgrades to meet NERC cyber security regulations on the Ben French CT's 1-4.

2014 Compared to 2013

Gross margin increased primarily due to a return on additional investments which increased base electric margins by $9.0 million, and increased rider margins from Cheyenne Prairie by $5.5 million. Industrial megawatt hours sold increased by approximately 15%, primarily due to load growth at Cheyenne Light resulting in increased margins of $1.7 million. Facility improvements at one of our large industrial customers drove a $1.8 million increase in technical service revenues. These increases were partially offset by a $3.5 million decrease from lower demand and residential megawatt hours sold driven by a 29% decrease in cooling degree days compared to the same period in the prior year, a $1.6 million decrease from the TCA, and a $0.8 million decrease from a construction savings incentive recognized in the prior year. Our Cheyenne Light gas utility experienced a decrease in heating degree days, resulting in a $1.4 million decrease in retail natural gas sales.

Operations and maintenance increased primarily due to property taxes, regulatory support and legal fees, generation maintenance, and employee costs.

Depreciation and amortization increased primarily due to a higher asset base driven by the addition of Cheyenne Prairie.

Interest expense, net decreased primarily due to lower interest rates from refinancing higher cost debt in the fourth quarter of 2013, and extending our revolving credit facility under favorable terms during the second quarter of 2014.

Income tax benefit (expense): The effective tax rate was comparable to the same period in the prior year.

2013 Compared to 2012

Gross margin increased primarily due to a return on additional investments which increased base electric margins by $5.9 million, increased rider margins by $9.4 million and a $2.2 million increase at our gas utility due to an increase in volumes driven by a 17% increase in heating degree days. These are partially offset by a $2.1 million construction savings incentive received by Colorado Electric in 2012 compared to $0.7 million received in 2013.

Operations and maintenance increased primarily due to property taxes, vegetation management and employee costs. Prior year included a $2.1 million reduction of major maintenance accruals related to plant suspensions and retirements.

Depreciation and amortization increased primarily due to a higher asset base.

Interest expense, net increased primarily due to lower AFUDC.

Income tax benefit (expense): The effective tax rate decreased primarily due to an unfavorable income tax true-up adjustment that impacted 2012.

Gas Utilities

Operating results for the years ended December 31 for the Gas Utilities were as follows (in thousands):

	2014	Variance	2013	Variance	2012
Revenue:					
Natural gas - regulated	$587,378	$77,123	$510,255	$84,987	$425,268
Other - non-regulated	30,390	956	29,434	621	28,813
Total revenue	617,768	78,079	539,689	85,608	454,081
Cost of natural gas sold:					
Natural gas - regulated	365,034	69,609	295,425	64,163	231,262
Other - non-regulated	15,818	780	15,038	951	14,087
Total cost of natural gas sold	380,852	70,389	310,463	65,114	245,349
Gross margin:					
Natural gas - regulated	222,344	7,514	214,830	20,824	194,006
Other - non-regulated	14,572	176	14,396	(330)	14,726
Total gross margin	236,916	7,690	229,226	20,494	208,732
Operations and maintenance	132,635	6,562	126,073	8,683	117,390
Depreciation and amortization	26,499	118	26,381	1,218	25,163
Total operating expenses	159,134	6,680	152,454	9,901	142,553
Operating income	77,782	1,010	76,772	10,593	66,179
Interest expense, net	(15,284)	8,974	(24,258)	(277)	(23,981)
Other expense (income), net	34	94	(60)	(165)	105
Income tax expense	(20,663)	(916)	(19,747)	(5,434)	(14,313)
Income from continuing operations	$41,869	$9,162	$32,707	$4,717	$27,990

2014 Compared to 2013

Gross margin increased primarily due to higher transport volumes which increased transport margins by $1.7 million. Rider margins increased $2.9 million primarily due to additional capital investments, and $1.6 million of additional margin was attributed to year over year customer growth. Higher retail volumes sold, driven mostly by a 7 percent increase in heating degree days realized in the first quarter of 2014 resulted in a $1.2 million increase. Heating degree days for the twelve months ended December 31, 2014, were 2% lower than the same period in the prior year, and 7% higher than normal.

Operations and maintenance increased primarily due to employee costs, property taxes, outside services, and uncollectible accounts attributed to increased revenue.

Depreciation and amortization was comparable to the same period in the prior year.

Interest expense, net decreased primarily due to lower interest rates from refinancing higher cost debt in the fourth quarter of 2013.

Income tax: The effective tax rate for 2014 was lower primarily due to a favorable true-up adjustment to the filed 2013 income tax return, in addition to an increase in flow-through tax adjustments.

2013 Compared to 2012

Gross margin increased primarily due to a $12 million increase resulting from higher retail volumes driven by a 25% increase in heating degree days. Transport margins increased $2.9 million, surcharge revenue increased $1.9 million primarily due to additional capital investments and $1.3 million of additional margin was attributed to year over year customer growth.

Operations and maintenance increased primarily due to employee costs, property taxes and uncollectible accounts attributed to increased revenue.

Depreciation and amortization increased primarily due to a higher asset base.

Interest expense, net was comparable to the same period in the prior year.

Income tax: The effective tax rate for 2013 increased primarily as a result of favorable flow-through tax adjustment that benefited 2012.

Non-regulated Energy Group

Power Generation

Our Power Generation segment operating results for the years ended December 31 were as follows (in thousands):

	2014	Variance	2013	Variance	2012
Revenue	$87,558	$4,521	$83,037	$3,648	$79,389
Operations and maintenance	33,126	2,940	30,186	195	29,991
Depreciation and amortization	4,540	(551)	5,091	492	4,599
Total operating expenses	37,666	2,389	35,277	687	34,590
Operating income	49,892	2,132	47,760	2,961	44,799
Interest expense, net	(3,669)	16,724	(20,393)	(5,636)	(14,757)
Other income (expense), net	(6)	(7)	1	(6)	7
Income tax expense	(17,701)	(6,621)	(11,080)	(2,359)	(8,721)
Income from continuing operations	$28,516	$12,228	$16,288	$(5,040)	$21,328

	2014	2013	2012
Contracted fleet plant availability:			
Gas-fired plants	99.0%	99.0%	99.4%
Coal-fired plants [(a)]	94.7%	94.5%	99.6%
Total	97.8%	97.9%	99.4%

(a) Wygen I experienced planned outages in 2014 and 2013.

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2014 Compared to 2013

Revenue increased primarily due to an increase in megawatt hours delivered at higher prices, an increase in fired hours, and an increase from the new economy energy PPA with the City of Gillette, partially offset by the expiration of the CTII capacity contract with Cheyenne Light.

Operations and maintenance increased primarily due to increased outside services and materials, and additional maintenance costs on the Wygen I outage, partially offset by decreased employee costs.

Depreciation and amortization decreased primarily due to lower depreciation at Black Hills Wyoming. The generating facility located in Pueblo, Colo. is accounted for as a capital lease under GAAP; as such, depreciation expense for the original cost of the facility is recorded at Colorado Electric for segment reporting purposes.

Interest expense, net decreased primarily due to refinancing higher cost project debt and settling associated interest rate swaps in the fourth quarter of 2013. The fourth quarter of 2013 included $7.7 million relating to the cost to settle the interest rate swaps associated with Black Hills Wyoming’s project financing and a $2.4 million write-off of related deferred financing costs.

Income tax expense: The effective tax rate was comparable to the same period in the prior year.

2013 Compared to 2012

Revenue increased primarily due to $2.1 million relating to increased MWh delivered at higher prices and $2.3 million related to increased volumes and pricing for off-system sales at Black Hills Wyoming.

Operations and maintenance increased primarily due to two Wygen I outages, partially offset by decreased property taxes at Black Hills Colorado IPP.

Depreciation and amortization were comparable to the same period in the prior year. The generating facility located in Pueblo, Colorado is accounted for as a capital lease under GAAP; as such, depreciation expense for the original cost of the facility is recorded at Colorado Electric for segment reporting purposes.

Interest expense, net increased primarily due to $7.7 million relating to the cost to settle the interest rate swaps associated with Black Hills Wyoming’s project financing and a $2.4 million write-off of related deferred financing costs, partially offset by lower inter-company debt.

Income tax expense: The effective tax rate in 2013 increased as a result of an unfavorable tax true-up adjustment.

Coal Mining

Coal Mining operating results for the years ended December 31 were as follows (in thousands):

	2014	Variance	2013	Variance	2012
Revenue	$63,358	$6,730	$56,628	$(1,150)	$57,778
Operations and maintenance	41,172	1,653	39,519	(3,034)	42,553
Depreciation, depletion and amortization	10,276	(1,247)	11,523	(1,537)	13,060
Total operating expenses	51,448	406	51,042	(4,571)	55,613
Operating income (loss)	11,910	6,324	5,586	3,421	2,165
Interest (expense) income, net	(434)	197	(631)	(1,561)	930
Other income, net	2,275	(29)	2,304	(312)	2,616
Income tax benefit (expense)	(3,299)	(2,367)	(932)	(847)	(85)
Income (loss) from continuing operations	$10,452	$4,125	$6,327	$701	$5,626

The following table provides certain operating statistics for the Coal Mining segment (in thousands):

	2014	2013	2012
Tons of coal sold	4,317	4,285	4,246
Cubic yards of overburden moved	4,646	3,192 [a]	8,329
Coal reserves at year-end	208,231	212,595 [b]	232,265

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(a) Reduction in overburden was due to relocating mining operations in the second half of 2012 to an area of the mine with lower overburden.

(b) Reduction in coal reserves was due to revisions in coal modeling based upon engineering data, changes in coal limit boundaries and current coal production.

2014 Compared to 2013

Revenue increased primarily due to an 11% increase in the price per ton sold driven primarily by a coal price increase with the third-party operator of the Wyodak plant. Price per ton also increased as a result of an increase in pricing on contracts containing price adjustments based on actual mining costs. Approximately 50% of our coal production is sold under contracts that include price adjustments based on actual mining costs, including income taxes. Our mining costs have increased due to higher operations and maintenance costs driven by mining in areas with a higher stripping ratio than the prior year, thereby increasing our price per ton for these customers.

Operations and maintenance increased primarily due to mining in areas with higher overburden, materials and outside services on major maintenance projects, and an increase in royalties and revenue related taxes driven by increased revenue, partially offset by lower employee costs.

Depreciation, depletion and amortization decreased primarily due to lower depreciation on mine assets driven by a reduction in equipment run hours from changes in the mine plan design, and lower depreciation of mine reclamation costs.

Interest (expense) income, net is comparable to the same period in the prior year.

Income tax: The effective tax rate in 2014 is higher due to the reduced impact of the tax benefit of percentage depletion.

2013 Compared to 2012

Revenue decreased primarily due to a 9% decrease in the average price per ton charged on coal sold under contracts containing price adjustments, partially offset by a 1% increase in tons sold. Approximately 50% of our coal production is sold under contracts that include price adjustments based on actual mining costs, including income taxes. Our mining costs have trended down due to lower operations and maintenance costs, thereby decreasing our price per ton for these customers.

Operations and maintenance decreased primarily due to mining in areas with lower overburden, resulting in decreased fuel costs and reduced employee costs, partially offset by materials and outside services related to major maintenance projects.

Depreciation, depletion and amortization decreased primarily due to lower depreciation on mine assets and lower depreciation of mine reclamation costs.

Interest (expense) income, net reflects decreased interest income primarily due to a decrease in the inter-company notes receivable, reduced by payment of a dividend to our parent.

Income tax benefit (expense): The effective tax rate increased in 2013 as a result of lower percentage depletion. In addition, the effective tax rate in 2012 was impacted by a favorable true-up adjustment that was primarily driven by an increased percentage depletion deduction reported on the 2011 tax return.

Oil and Gas

Oil and Gas operating results for the years ended December 31 were as follows (in thousands):

	2014	Variance	2013	Variance	2012
Revenue	$55,114	$230	$54,884	$(24,188)	$79,072
Operations and maintenance	42,659	2,294	40,365	(2,902)	43,267
Gain on sale of assets	—	—	—	29,129	(29,129)
Depreciation, depletion and amortization	27,584	5,814	21,770	(16,724)	38,494
Impairment of long-lived assets	—	—	—	(26,868)	26,868
Total operating expenses	70,243	8,108	62,135	(17,365)	79,500
Operating income (loss)	(15,129)	(7,878)	(7,251)	(6,823)	(428)
Interest expense, net	(1,685)	(1,071)	(614)	3,321	(3,935)
Other income (expense), net	183	75	108	(99)	207
Income tax benefit (expense)	5,998	2,453	3,545	1,618	1,927
Income (loss) from continuing operations	$(10,633)	$(6,421)	$(4,212)	$(1,983)	$(2,229)

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The following tables provide certain operating statistics for the Oil and Gas segment:

Crude Oil and Natural Gas Production	2014	2013	2012
Bbls of oil sold	337,196	336,140	559,971
Mcf of natural gas sold	7,155,076	6,983,104	8,686,191
Bbls of NGL sold	134,555	88,205	82,989
Mcf equivalent sales	9,985,584	9,529,178	12,543,948

Average Price Received [(a)]	2014	2013	2012
Gas/Mcf	$2.91	$2.69	$3.33
Oil/Bbl	$79.39	$89.34	$83.27
NGL/Bbl	$35.53	$33.15	$32.41

(a) Net of hedge settlement gains/losses

	2014	2013	2012
Depletion expense/Mcfe*	$2.21	$1.83	$2.87

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* The average depletion rate per Mcfe is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented. The decreased depletion rate in 2013 is primarily driven by the Williston Basin sale in 2012. See Note 21 of Notes to the Consolidated Financial Statements included in this Annual Report filed on Form 10-K.

The following is a summary of certain annual average costs per Mcfe at December 31:

2014	LOE	Gathering, Compression, Processing and Transportation	Production Taxes	Total
San Juan	$1.52	$1.11	$0.56	$3.19
Piceance	0.31	3.74	0.38	4.43
Powder River	1.77	—	1.26	3.03
Williston	1.46	—	1.24	2.70
All other properties	1.43	—	0.43	1.86
Average	$1.24	$1.37	$0.68	$3.29

2013	LOE	Gathering, Compression, Processing and Transportation	Production Taxes	Total
San Juan	$1.33	$0.96	$0.45	$2.74
Piceance	0.69	1.68	0.04	2.41
Powder River	1.66	—	1.18	2.84
Williston	1.06	—	1.38	2.44
All other properties	0.86	—	0.18	1.04
Average	$1.22	$0.66	$0.60	$2.48

	2012			
	LOE	Gathering, Compression, Processing and Transportation	Production Taxes	Total
San Juan	$1.22	$0.71	$0.35	$2.28
Piceance	0.30	1.29	0.17	1.76
Powder River	1.57	—	1.18	2.75
Williston	0.35	—	1.35	1.70
All other properties	1.91	—	0.34	2.25
Average	$1.05	$0.49	$0.64	$2.18

In the Piceance and San Juan Basins, our natural gas is transported through our own and third-party gathering systems and pipelines, for which we incur processing, gathering, compression and transportation fees. The sales price for natural gas, condensate and NGLs is reduced for these third-party costs, and the cost of operating our own gathering systems is included in operations and maintenance. The gathering, compression, processing and transportation costs shown in the tables above include amounts paid to third parties, as well as costs incurred in operations associated with our own gas gathering, compression, processing and transportation.

We revised our presentation of these costs in 2014 to include both third-party costs and operations costs, and have restated the 2013 and 2012 amounts accordingly. Our 2014 amounts were impacted by a ten-year gas gathering and processing contract for natural gas production in our Piceance Basin in Colorado that became effective in 2014. This take or pay contract requires us to pay the fee on a minimum of 20,000 Mcf per day, regardless of the volume delivered. In 2014 our delivery of production did not meet the minimum requirement; therefore our cost per Mcfe increased as illustrated in the table above.

The following is a summary of our proved oil and gas reserves at December 31:

	2014	2013	2012
Bbls of oil (in thousands)	4,276	3,921	4,116
MMcf of natural gas	65,440	63,190	55,985
Bbls of NGLs (in thousands) [(a)]	1,720	—	—
Total MMcfe	101,416	86,713	80,683

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(a) NGL reserves for 2013 and 2012 are not available and were included with MMcf of natural gas in 2013 and 2012.

Reserves are based on reports prepared by an independent consulting and engineering firm. The reports were prepared by CG&A. Reserves were determined using SEC-defined product prices. Such reserve estimates are inherently imprecise and may be subject to revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. The current estimate takes into account 2014 production of approximately 10.0 Bcfe, additions from extensions, discoveries and acquisitions (sales) of 16.2 Bcfe and positive revisions to previous estimates of 8.5 Bcfe, primarily due to oil and natural gas pricing.

Reserves reflect SEC-defined pricing held constant for the life of the reserves, as follows:

	2014		2013		2012	
	Oil	Gas	Oil	Gas	Oil	Gas
NYMEX prices	$94.99	$4.35	$96.94	$3.67	$94.71	$2.76
Well-head reserve prices	$85.80	$3.33	$89.79	$3.45	$85.31	$2.24

2014 Compared to 2013

Revenue increased primarily due to a 5% increase in volumes sold and an 8% increase in average price received for natural gas sold, partially offset by an 11% decrease in the average price received for crude oil sold.

Operations and maintenance increased primarily due to increased employee costs, higher lease operating and field operation expense, and higher production taxes and ad valorem taxes on higher revenue.

Depreciation, depletion and amortization increased primarily due to a higher depletion rate applied to increased production.

Interest expense, net increased primarily due to third-party interest received on non-operated well revenue in the prior year that offset 2013 expense.

Income tax (expense) benefit: Each period presented reflects a tax benefit. The tax benefit for 2014 was impacted by an unfavorable true-up adjustment to the filed 2013 income tax return.

2013 Compared to 2012

Revenue decreased primarily due to a 24% decrease in volumes sold as a result of the sale of our Williston Basin assets in 2012, a natural production decline in our gas wells and a 19% decrease in average price received for natural gas sold, partially offset by a 7% increase in the average price received for crude oil sold.

Operations and maintenance decreased primarily due to lower non-operated well costs and lower production taxes and ad valorem taxes on reduced revenue.

Gain on sale of operating assets represents the gain on the sale of our Williston Basin assets in 2012. We follow the full-cost method of accounting for oil and gas activities, which typically does not allow for gain on sale recognition unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves. The remainder of the sale amount not recognized as gain reduced the full-cost pool and had the effect of reducing the depreciation, depletion and amortization rate.

Depreciation, depletion and amortization decreased primarily due to a lower proportion of our total reserves being from crude oil in 2013, resulting from the sale of our Williston Basin assets in 2012.

Impairment of long-lived assets represents a write-down in the value of our natural gas and crude oil properties driven by low natural gas prices in the second quarter of 2012. The write-down reflected a 12-month average NYMEX price of $3.15 per Mcf, adjusted to $2.66 per Mcf at the wellhead, for natural gas and $95.67 per barrel, adjusted to $85.36 per barrel at the wellhead, for crude oil.

Interest expense, net reflects lower interest expense primarily due to decreased debt as a result of proceeds from the sale of our Williston Basin assets in 2012.

Income tax (benefit) expense: Each period presented produced a pre-tax net loss that resulted in an income tax benefit. The effective tax rate in 2013 reflects lower percentage depletion.

Corporate

Corporate results represent certain unallocated costs for administrative activities that support the business segments. Corporate also includes business development activities that do not fall under the two business groups as well as allocated costs associated with discontinued operations that could not be included in discontinued operations.

2014 Compared to 2013

Loss from continuing operations for the twelve months ended December 31, 2014, was $1 million compared to income from continuing operations of $13 million for the same period in the prior year. Results for the year ended December 31, 2014 increased primarily due to refinancing activity that took place during the fourth quarter of 2013. Results for the twelve months ended December 31, 2013 reflect a $30 million non-cash unrealized mark-to-market gain related to certain interest rate swaps. Corporate results for 2013 also include $10 million of costs related to early retirement of $250 million senior unsecured notes including a make-whole premium, write-off of deferred financing costs and interest expense on new debt.

2013 Compared to 2012

Corporate results for 2013 include costs of $10 million for a make-whole premium and write-off of deferred financing costs related to early retirement of our $250 million senior unsecured notes and interest expenses on new debt, compared to $7.1 million for a make-whole premium related to the early retirement of our $225 million senior unsecured notes in 2012. We also had an unrealized, non-cash mark-to-market gain on certain interest rate swaps of approximately $30 million in 2013, compared to an unrealized, non-cash mark-to-market gain of $1.9 million on these interest rate swaps for the year ended December 31, 2012.

2012 includes costs of $0.9 million previously allocated to our Energy Marketing segment were reclassified to the Corporate activities consistent with accounting for discontinued operations.

Discontinued Operations

On February 29, 2012, we sold the outstanding stock of Enserco, our Energy Marketing segment. Net cash proceeds at date of sale were approximately $165 million, subject to final post-closing adjustments.

The buyer asserted certain purchase price adjustments, some that we accepted, and several that we disputed. The disputed claims were substantially resolved through a binding arbitration decision dated January 17, 2014. We expensed an additional $1.1 million in 2013 related to the claims assigned to arbitration from purchase price adjustments we accepted through a partial settlement agreement with the buyer. Loss from discontinued operations was $0.9 million for the twelve months ended December 31, 2013. Results for 2013 include the resolution of all previously unresolved purchase price adjustments.

Critical Accounting Estimates

We prepare our consolidated financial statements in conformity with GAAP. In many cases, the accounting treatment of a particular transaction is specifically dictated by GAAP and does not require management’s judgment in application. There are also areas which require management’s judgment in selecting among available GAAP alternatives. We are required to make certain estimates, judgments and assumptions that we believe are reasonable based upon the information available. These estimates and assumptions affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. Actual results may differ from our estimates and to the extent there are material differences between these estimates, judgments, or assumptions and actual results, our financial statements will be affected. We believe the following accounting estimates are the most critical in understanding and evaluating our reported financial results. We have reviewed these critical accounting estimates and related disclosures with our Audit Committee.

The following discussion of our critical accounting estimates should be read in conjunction with Note 1, “Business Description and Significant Accounting Policies” of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Goodwill

We perform our goodwill impairment test as of November 30 each year or upon the occurrence of events or changes in circumstances that indicate that the asset might be impaired. Accounting standards for testing goodwill for impairment require a two-step process be performed to analyze whether or not goodwill has been impaired. Goodwill is tested for impairment at the reporting unit level. Our reporting units have been determined to be at the subsidiary level. The first step of this test, used to identify potential impairment, compares the estimated fair value of a reporting unit with its carrying amount, including goodwill. If the carrying amount exceeds fair value under the first step, then the second step of the impairment test is performed to measure the amount of any impairment loss.

Application of the goodwill impairment test requires judgment, including the identification of reporting units and determining the fair value of the reporting unit. We estimate the fair value of our reporting units using a combination of an income approach, which estimates fair value based on discounted future cash flows, and a market approach, which estimates fair value based on market comparables within the utility and energy industries. These valuations require significant judgments, including, but not limited to: 1) estimates of future cash flows, based on our internal five-year business plans with long range cash flows estimated using a terminal value calculation and adjusted as appropriate for our view of market participant assumptions, 2) estimates of long-term growth rates for our businesses, 3) the determination of an appropriate weighted-average cost of capital or discount rate, and 4) the utilization of market information such as recent sales transactions for comparable assets within the utility and energy industries.

We have $353 million in goodwill as of December 31, 2014. The results of our November 30, 2014, annual impairment test indicated that our goodwill was not impaired, since the estimated fair value of all reporting units exceeded their carrying value.

Although an impairment did not exist as of November 30, 2014, we determined that one reporting unit, Colorado Electric with goodwill of $245 million, had an estimated fair value that exceeded its carrying value by 24%, which we do not consider a substantial excess. The result of our valuation analysis estimates Colorado Electric's fair value at $860 million, compared to a carrying value of $694 million as of November 30, 2014. The result of the income approach was sensitive to the 2% long-term cash flow growth rate applicable to periods beyond our internal five-year business plan financial forecast and the 5.04% weighted-average cost of capital assumptions. As an illustration of this sensitivity, an increase of 0.25% in the cost of capital combined with a growth rate reduction of 0.25% would result in an estimated fair value in excess of carrying value of $99 million, or 14%, as of November 30, 2014.

Full Cost Method of Accounting for Oil and Gas Activities

Accounting for oil and gas activities is subject to special, unique rules. Two generally accepted methods of accounting for oil and gas activities are available - successful efforts and full cost. We account for our oil and gas activities under the full cost method, whereby all productive and nonproductive costs related to acquisition, exploration, development, abandonment and reclamation activities are capitalized. These costs are amortized using a unit-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are generally treated as adjustments to the cost of the properties with no gain or loss recognized. Net capitalized costs are subject to a ceiling test that limits such costs to the aggregate of the present value of future net revenues of proved reserves and the lower of cost or fair value of unproved properties. This method values the reserves based upon SEC-defined prices for oil and gas as of the end of each reporting period adjusted for contracted price changes. The prices, as well as costs and development capital, are assumed to remain constant for the remaining life of the properties. If the net capitalized costs exceed the full-cost ceiling, then a permanent non-cash write-down is required to be charged to earnings in that reporting period. Under these SEC-defined product prices, our net capitalized costs were more than the full cost ceiling at June 30, 2012, which required a write-down of $17 million after-tax. We’ve taken no further write-downs related to our oil and gas full-cost pool since then and under the

SEC-defined product prices at December 31, 2014, no write-down was required. Reserves in 2014 and 2013 were determined consistent with SEC requirements using a 12-month average price calculated using the first-day-of-the-month price for each of the 12 months in the reporting period held constant for the life of the properties. Because of the fluctuations in natural gas and oil prices, we can provide no assurance that future write-downs will not occur. However, if the current low price environment continues, it is probable that we will have an impairment in 2015.

As noted, we utilize the full-cost method of accounting for our oil and gas activities in accordance with SEC Rule 4-10 of Regulation S-X (Rule 4-10). Under the full-cost method, sales of oil and gas properties generally are recorded as an adjustment to capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between the capitalized costs and proved oil and gas reserves. The Company’s sale of oil and gas properties in the Williston Basin of North Dakota in 2012 was significant as defined by Rule 4-10 and, accordingly, a $19 million after-tax gain on sale was recorded. Total net cash proceeds from the sale were approximately $228 million.

Under the guidance of Rule 4-10, if a gain or loss is recognized on such a sale, total capitalized costs shall be allocated between the reserves sold and the reserves retained on the same basis used to compute amortization, unless there are substantial economic differences between the properties sold and those retained, in which case capitalized costs shall be allocated on the basis of the relative fair value of the properties in the cost center. Because of the substantial differences between the Williston Basin crude oil properties we sold and those properties retained, which were predominantly natural gas, we allocated based on relative fair values.
If a different method of allocating the capitalized costs was chosen, the gain recorded on our transaction could vary substantially. For example, if the allocation was made on the same basis used to compute amortization as noted within Rule 4-10 and we utilized the ratio of proven reserve quantities from the properties sold compared to total proven reserve quantities in our cost center, we would have recorded a gain on sale of approximately $160 million. Because of the value associated with the undeveloped acreage sold, we did not believe this was an appropriate methodology for allocation. If the amount of gain were recorded differently, it would impact the amount of adjustment to our capitalized costs therefore impacting future depletion expense recorded within our consolidated financial statements.
Oil, Natural Gas, and Natural Gas Liquids Reserve Estimates

Estimates of our proved oil, natural gas and NGL reserves are based on the quantities of each that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. An independent petroleum engineering company prepares reports that estimate our proved oil, natural gas and NGL reserves annually. The accuracy of any oil, natural gas and NGL reserve estimate is a function of the quality of available data, engineering judgment and geological interpretation. For example, we must estimate the amount and timing of future operating costs, severance taxes, development costs and work over costs, all of which may in fact vary considerably from actual results. In addition, as oil, natural gas and NGL prices and cost levels change from year to year, the estimate of proved reserves may also change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves.

Despite the inherent imprecision in estimating our oil, natural gas and NGL reserves, the estimates are used throughout our financial statements. For example, since we use the unit-of-production method of calculating depletion expense, the amortization rate of our capitalized oil and gas properties incorporates the estimated unit-of-production attributable to the estimates of proved reserves. The net book value of our oil and gas properties is also subject to a “ceiling” limitation based in large part on the value of our proved reserves. Finally, these reserves are the basis for our supplemental oil and gas disclosures.

Risk Management Activities

In addition to the information provided below, see Note 8, “Risk Management Activities” and Note 9, “Fair Value Measurement,” of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Derivatives

Accounting standards for derivatives require the recognition of all derivative instruments as either assets or liabilities on the balance sheet and their measurement at fair value. Our policy for recognizing the changes in fair value of derivatives varies based on the designation of the derivative. The changes in fair value of derivatives that are not designated as hedges are recognized currently in earnings. Derivatives may be designated as hedges of expected future cash flows or fair values. The effective portion of changes in fair values of derivatives designated as cash flow hedges is recorded as a component of other comprehensive income (loss) until it is reclassified into earnings in the same period that the hedged item is recognized in earnings. The ineffective portion of changes in fair value of derivatives designated as cash flow hedges is recorded in current earnings. Changes in fair value of derivatives designated as fair value hedges are recognized in current earnings along with fair value changes of the underlying hedged item.

We currently use derivative instruments, including options, swaps, and futures, for non-trading (hedging) purposes. Our typical hedging transactions relate to contracts we enter into to fix the price received for anticipated future production at our Oil and Gas segment, or to fulfill the natural gas hedging plans for gas and electric utilities and for interest rate swaps we enter into to convert a portion of our variable rate debt, or associated variable rate interest payments, to a fixed rate.

Fair values of derivative instruments contracts are based on actively quoted market prices or other external source pricing information, where possible. If external market prices are not available, fair value is determined based on other relevant factors and pricing models that consider current market and contractual prices for the underlying financial instruments or commodities, as well as time value and yield curve or volatility factors underlying the positions.

Pricing models and their underlying assumptions impact the amount and timing of unrealized gains and losses recorded and the use of different pricing models or assumptions could produce different financial results.

Pension and Other Postretirement Benefits

As described in Note 17 to the Consolidated Financial Statements in this Annual Report on Form 10-K, we have two defined benefit pension plans, three defined post-retirement healthcare plans and several non-qualified retirement plans. A Master Trust holds the assets for the Pension Plans. Each Pension Plan has an undivided interest in the Master Trust. Trusts for the funded portion of the post-retirement healthcare plans have also been established.

Accounting for pension and other postretirement benefit obligations involves numerous assumptions, the most significant of which relate to the discount rate for measuring the present value of future plan obligations; expected long-term rates of return on plan assets; rate of future increases in compensation levels; and healthcare cost projections. The determination of our obligation and expenses for pension and other postretirement benefits is dependent on the assumptions determined by management and used by actuaries in calculating the amounts. Although we believe our assumptions are appropriate, significant differences in our actual experience or significant changes in our assumptions may materially affect our pension and other postretirement obligations and our future expense.

The pension benefit cost for 2015 for our non-contributory funded pension plan is expected to be $13.2 million compared to $8.1 million in 2014. The estimated discount rate used to determine annual benefit cost accruals will be 4.20% in 2015; the discount rate used in 2014 was 5.05%. In selecting the discount rate, we consider cash flow durations for each plan's liabilities and returns on high credit quality fixed income yield curves for comparable durations.

We do not pre-fund our non-qualified pension plans. One of the three postretirement benefit plans is partially funded. The table below shows the expected impacts of an increase or decrease to our healthcare trend rate for our three Retiree Healthcare Plans (in thousands):

Change in Assumed Trend Rate	Impact on December 31, 2014 Accumulated Postretirement Benefit Obligation	Impact on 2014 Service and Interest Cost
Increase 1%	$2,635	$168
Decrease 1%	$(2,166)	$(136)

Contingencies

When it is probable that an environmental or other legal liability has been incurred, a loss is recognized when the amount of the loss can be reasonably estimated. Estimates of the probability and the amount of loss are made based on currently available facts. Accounting for contingencies requires significant judgment regarding the estimated probabilities and ranges of exposure to potential liability. Our assessment of our exposure to contingencies could change to the extent there are additional future developments, or as more information becomes available. If actual obligations incurred are different from our estimates, the recognition of the actual amounts could have a material impact on our financial position, results of operations and cash flows.

Income Taxes

The Company and its subsidiaries file consolidated federal income tax returns. Each tax paying entity records income taxes as if it were a separate taxpayer and consolidating adjustments are allocated to the subsidiaries based on separate company computations of taxable income or loss.

We use the liability method in accounting for income taxes. Under the liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities as well as operating loss and tax credit carryforwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements. We classify deferred tax assets and liabilities into current and non-current amounts based on the nature of the related assets and liabilities.

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. If we determine that we will be unable to realize all or part of our deferred tax assets in the future, an adjustment to the deferred tax asset would be charged to income in the period such determination was made. Although we believe our assumptions, judgments and estimates are reasonable, changes in tax laws or our interpretations of tax laws and the resolution of current and any future tax audits could significantly impact the amounts provided for income taxes in our consolidated financial statements. With respect to changes in tax law, the TIPA, which was enacted December 19, 2014, did not have a material impact on the amounts provided for income taxes including our ability to realize deferred tax assets. Certain provisions of the TIPA involving primarily the extension of 50% bonus depreciation resulted in the generation of a NOL for federal and state income tax purposes in 2014. In September 2013, the U.S. Treasury issued final regulations addressing the tax consequences associated with amounts paid to acquire, produce, or improve tangible property. The regulations had the effect of a change in law and as a result the impact was taken into account in the period of adoption. In general, such regulations apply to tax years beginning on or after January 1, 2014, with early adoption permitted. We implemented all of the provisions of the final regulations with the filing of the 2013 federal income tax return in September 2014. The adoption of the final regulations did not have a material impact on our consolidated financial statements.

See Note 14 in our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

Liquidity and Capital Resources

OVERVIEW

BHC and its subsidiaries require significant cash to support and grow our business. Our predominant source of cash is supplied by our operations and supplemented with corporate borrowings. This cash is used for, among other things, working capital, capital expenditures, dividends, pension funding, investments in or acquisitions of assets and businesses, payment of debt obligations and redemption of outstanding debt and equity securities when required or financially appropriate.

The most significant uses of cash are our capital expenditures, the purchase of natural gas for our Gas Utilities and our Power Generation segment, as well as the payment of dividends to our shareholders. We experience significant cash requirements during peak months of the winter heating season due to higher natural gas consumption and during periods of high natural gas prices.

We believe that our cash on hand, operating cash flows, existing borrowing capacity and ability to complete new debt and equity financings, taken in their entirety, provide sufficient capital resources to fund our ongoing operating requirements, debt maturities, anticipated dividends and anticipated capital expenditures discussed in this section.

The following table provides an informational summary of our financial position as of December 31 (dollars in thousands):

Financial Position Summary	2014	2013
Cash and cash equivalents	$21,218	$7,841
Restricted cash and equivalents	$2,056	$2
Short-term debt, including current maturities of long-term debt	$350,000	$82,500
Long-term debt	$1,267,589	$1,396,948
Stockholders’ equity	$1,376,024	$1,307,748

Ratios		
Long-term debt ratio	48 %	52 %
Total debt ratio	54 %	53 %

As described below in the Debt and Liquidity section, in 2014, we amended and extended our corporate Revolving Credit Facility through May 29, 2019 and completed the sale of $160 million of first mortgage bonds in a private placement providing permanent financing for Cheyenne Prairie. Additionally, during 2013, we issued $800 million in long-term debt and repaid approximately $640 million in short-term and long-term borrowings.

Significant Factors Affecting Liquidity

Although we believe we have sufficient resources to fund our cash requirements, there are many factors with the potential to influence our cash flow position, including seasonality, commodity prices, significant capital projects and acquisitions, requirements imposed by state and federal agencies and economic market conditions. We have implemented risk mitigation programs, where possible, to stabilize cash flow; however, the potential for unforeseen events affecting cash needs will continue to exist.

Weather Seasonality, Commodity Pricing and Associated Hedging Strategies

We manage liquidity needs through hedging activities, primarily in connection with seasonal needs of our utility operations (including seasonal peaks in fuel requirements), interest rate movements and commodity price movements.

Utility Factors

Our cash flows, and in turn liquidity needs in many of our regulated jurisdictions, can be subject to fluctuations in weather and commodity prices. Since weather conditions are uncontrollable, we have implemented commission-approved natural gas hedging programs in many of our regulated jurisdictions to mitigate significant changes in natural gas commodity pricing. We target hedging approximately 50% to 70% of our forecasted natural gas supply using options, futures and basis swaps.

Oil and Gas Factors

Our cash flows in our Oil and Gas segment can be subject to fluctuations in commodity prices. Significant changes in crude oil or natural gas commodity prices can have a significant impact on liquidity needs. Since commodity prices are uncontrollable, we have implemented a hedging program to mitigate the effects of significant changes in crude oil and natural gas commodity pricing on existing production. New production is subject to market prices until the production can be quantified and hedged. We use a price-based approach where, based on market pricing, our existing natural gas and crude oil production can be hedged using options, futures and basis swaps for a maximum term of three years forward. See “Market Risk Disclosures” for hedge details.

Interest Rates

Several of our debt instruments have a variable interest rate component which can change significantly depending on the economic climate. We deploy hedging strategies that include floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations. At December 31, 2014, 82% of our interest rate exposure has been mitigated through either fixed or hedged interest rates.

We have $75 million notional amount floating-to-fixed interest rate swaps with a maximum remaining term of 2 years. These swaps have been designated as cash flow hedges and accordingly their mark-to-market adjustments are recorded in accumulated other comprehensive income (loss) on the accompanying Consolidated Balance Sheets. The mark-to-market value of these swaps was a liability of $6.0 million at December 31, 2014.

Until November 2013, we had $250 million notional amount de-designated interest rate swaps. We paid approximately $64 million to settle these swaps in November 2013. We recognized a $30 million non-cash pre-tax unrealized mark-to-market gain on these de-designated interest rate swaps for the year ended December 31, 2013.

Until November 2013, we also had interest rates swaps with a notional amount of $75 million designated as cash flow hedges to our Black Hills Wyoming project financing debt. We paid $8.5 million to settle these swaps upon repayment of the debt.

Federal and State Regulations

Federal

We are structured as a utility holding company which owns several regulated utilities. Within this structure, we are subject to various regulations by our commissions that can influence our liquidity. As an example, the issuance of debt by our regulated subsidiaries and the use of our utility assets as collateral generally require the prior approval of the state regulators in the state in which the utility assets are located. Furthermore, as a result of our holding company structure, our right as a common shareholder to receive assets of any of our direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization is subordinate to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities and guarantee holders.

Income Tax

Acceleration of depreciation for tax purposes including 50% bonus depreciation was previously available for certain property placed in service during 2013. TIPA, enacted into law on December 19, 2014, extended 50% bonus depreciation generally to qualifying property placed in service during 2014. These provisions resulted in approximately $122 million of tax benefits for BHC as indicated in the table below:

(in millions)	2014	2013	2012
Tax benefit	$67	$24	$31

In addition, bonus depreciation applies to qualifying property whose construction began before 2015, but will be placed in service on or before December 31, 2016. No projects will qualify under this provision. The additional depreciation deductions will serve to reduce taxable income and contribute to extending the tax loss carryforwards from being fully utilized until 2020 based on current projections.

The cash generated by bonus depreciation is an acceleration of tax benefits that we would have otherwise received over 15 to 20 years. Additionally, from a regulatory perspective, while the capital additions at the Company's regulated businesses generally increase future revenue requirements, the bonus depreciation associated with these capital additions will partially mitigate future rate increases related to capital additions.

See Note 14 in our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

CASH GENERATION AND CASH REQUIREMENTS

Cash Generation

Our primary sources of cash are generated from operating activities, our five-year Revolving Credit Facility expiring May 29, 2019 and our ability to access the public and private capital markets through debt and securities offerings when necessary.

Cash Collateral

Under contractual agreements and exchange requirements, BHC or its subsidiaries have collateral requirements, which if triggered, require us to post cash collateral positions with the counterparty to meet these obligations.

We have posted the following amounts of cash collateral with counterparties at December 31 (in thousands):

Purpose of Cash Collateral	2014	2013
Natural Gas Futures and Basis Swaps Pursuant to Utility Commission Approved Hedging Programs	$20,007	$10,123
Oil and Gas Derivatives	4,392	2,501
Total Cash Collateral Positions	$24,399	$12,624

DEBT

Operating Activities

Our principal sources to meet day-to-day operating cash requirements are cash from operations and our corporate Revolving Credit Facility.

Revolving Credit Facility

On May 29, 2014, we amended our $500 million corporate Revolving Credit Facility agreement to extend the term through May 29, 2019. This facility is substantially similar to the former agreement, which includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents, to increase the capacity of the facility to $750 million. Borrowings continue to be available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings and the commitment fee under the Revolving Credit Facility are determined based upon our most favorable Corporate credit rating from S&P and Moody's for our unsecured debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings and letters of credit were 0.125%, 1.125%, and 1.125%, respectively, from May 29, 2014 through December 31, 2014; a reduction of 0.25% for each method of borrowing as compared to the previous arrangement. A commitment fee was charged on the unused amount of the Revolving Credit Facility and was 0.175% based on our credit rating, a reduction of 0.025% compared to the prior arrangement.

Our Revolving Credit Facility at December 31, 2014, had the following borrowings, outstanding letters of credit and available capacity (in millions):

Credit Facility	Expiration	Current Capacity	Borrowings at December 31, 2014	Letters of Credit at December 31, 2014	Available Capacity at December 31, 2014
Revolving Credit Facility	May 29, 2019	$500	$75	$35	$390

The Revolving Credit Facility contains customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions and maintaining a certain recourse leverage ratio. Under the Revolving Credit Facility, our recourse leverage ratio is calculated by dividing the sum of our recourse debt, letters of credit and certain guarantees issued, by total capital, which includes recourse indebtedness plus our net worth. Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding. We were in compliance with these covenants as of December 31, 2014.

The Revolving Credit Facility prohibits us from paying cash dividends if a default or an event of default exists prior to, or would result after paying a dividend. Although these contractual restrictions exist, we do not anticipate triggering any default measures or restrictions.

Capital Resources

Our principal sources for our long-term capital needs have been issuances of long-term debt securities by the Company and its subsidiaries along with proceeds obtained from public and private offerings of equity.

Recent Financing Transactions

On October 1, 2014, Black Hills Power and Cheyenne Light sold $160 million of first mortgage bonds in a private placement to provide permanent financing for Cheyenne Prairie. Black Hills Power issued $85 million of 4.43%

coupon first mortgage bonds due October 20, 2044 and Cheyenne Light issued $75 million of 4.53% coupon first mortgage bonds due October 20, 2044. Proceeds from Black Hills Power's bond sale also funded the early redemption of its 5.35% coupon $12 million pollution control revenue bonds, originally due October 1, 2024.

On November 19, 2013, we entered into a new $525 million, 4.25% unsecured note expiring on November 30, 2023. The proceeds from this new debt were used to:

- Redeem our $250 million senior unsecured 9.0% notes originally due on May 15, 2014. This repayment occurred on December 19, 2013, for approximately $261 million which included a make-whole provision of approximately $8.5 million and accrued interest.

- Repay our variable interest rate Black Hills Wyoming project financing with a remaining balance of $87 million originally due on December 9, 2016 and settle the interest rate swaps designated to this project financing of $8.5 million.

- Settle the $250 million notional de-designated interest rate swaps for approximately $64 million.

- Pay down $55 million of the Revolving Credit Facility.

- Remainder was used for general corporate purposes.

On June 21, 2013, we entered into a new two-year $275 million term loan expiring on June 19, 2015. The proceeds from this new term loan repaid the $150 million term loan due on June 24, 2013, the $100 million corporate term loan due on September 30, 2013 and $25 million in short-term borrowing under our Revolving Credit Facility. At December 31, 2014, the cost of borrowing under this new term loan was 1.313% (LIBOR plus a margin of 1.125%).

Future Financing Plans

During the next three years, BHC plans to consider completing the following financing activities to take advantage of the current, relatively-low interest rate environment:

- Evaluate alternatives for the $275 million term loan due June 19, 2015.

Cross-Default Provisions

Our $275 million corporate term loan contains cross-default provisions that could result in a default under such agreements if BHC or its material subsidiaries failed to make timely payments of debt obligations or triggered other default provisions under any debt agreement totaling in the aggregate principal amount of $35 million or more that permits the acceleration of debt maturities or mandatory debt prepayment. Our Revolving Credit Facility contains the same provisions; however the threshold principal amount is $50 million.

The Revolving Credit Facility prohibits us from paying cash dividends if we are in default or if paying dividends would cause us to be in default.

Equity

Based on our current capital spending forecast, we do not anticipate the need to access the equity capital markets in the next three years.

Shelf Registration

We have an effective automatic shelf registration statement on file with the SEC under which we may issue, from time to time, senior debt securities, subordinated debt securities, common stock, preferred stock, warrants and other securities. Although the shelf registration statement does not limit our issuance capacity, our ability to issue securities is limited to the authority granted by our Board of Directors, certain covenants in our financing arrangements and restrictions imposed by federal and state regulatory authorities. This shelf registration expires in August 2017. Our articles of incorporation authorize the issuance of 100 million shares of common stock and 25 million shares of preferred stock. As of December 31, 2014, we had approximately 45 million shares of common stock outstanding and no shares of preferred stock outstanding.

Common Stock Dividends

Future cash dividends, if any, will be dependent on our results of operations, financial position, cash flows, reinvestment opportunities and other factors which will be evaluated and approved by our Board of Directors.

In January 2015, our Board of Directors declared a quarterly dividend of $0.405 per share or an annualized equivalent dividend rate of $1.62 per share. The table below provides our historical three-year dividend payout ratio and dividends paid per share:

	2014	2013	2012
Dividend Payout Ratio	54%	59%	80%
Dividends Per Share	$1.56	$1.52	$1.48

Our three-year compound annualized dividend growth rate was 2.2% and all dividends were paid out of available operating cash flows.

Dividend Restrictions

As a utility holding company which owns several regulated utilities, we are subject to various regulations that could influence our liquidity. For example, the issuance of debt by our utility subsidiaries (including the ability of Black Hills Utility Holdings to issue debt) and the use of our utility assets as collateral generally requires the prior approval of the state regulators in the state in which the utility assets are located. As a result of our holding company structure, our right as a common shareholder, to receive assets from any of our direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization, is junior to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities and guarantee holders.

Our credit facilities and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be deemed to have occurred if we did not meet certain financial covenants. The most restrictive financial covenants of our Revolving Credit Facility include the following: a recourse leverage ratio not to exceed .65 to 1.00. As of December 31, 2014, we were in compliance with these covenants.

Covenants within Cheyenne Light's financing agreements require Cheyenne Light to maintain a debt to capitalization ratio of no more than .60 to 1.00. Our utilities in Colorado, Iowa, Kansas and Nebraska have regulatory agreements in which they cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40% of their total capitalization; and neither Black Hills Utility Holdings nor its utility subsidiaries can extend credit to the Company except in the ordinary course of business and upon reasonable terms consistent with market terms. Additionally, our utility subsidiaries may generally be limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As of December 31, 2014, the restricted net assets at our Electric and Gas Utilities were approximately $315 million.

Utility Money Pool

As a utility holding company, we are required to establish a cash management program to address lending and borrowing activities between our utility subsidiaries and the Company. We have established utility money pool agreements which address these requirements. These agreements are on file with the FERC and appropriate state regulators. Under the utility money pool agreements, our utilities may at their option, borrow and extend short-term loans to our other utilities via a utility money pool at market-based rates (1.3550% at December 31, 2014). While the utility money pool may borrow funds from the Company (as ultimate parent company), the money pool arrangement does not allow loans from our utility subsidiaries to the Company (as ultimate parent company) or to non-regulated affiliates.

At December 31, money pool balances included (in thousands):

	Borrowings From (Loans To) Money Pool Outstanding	
Subsidiary	2014	2013
Black Hills Utility Holdings	$88,551	$128,587
Black Hills Power	(68,626)	(17,293)
Cheyenne Light	28,663	65,772
Total Money Pool borrowings from Parent	$48,588	$177,066

CASH FLOW ACTIVITIES

The following table summarizes our cash flows (in thousands):

	2014	2013	2012
Cash provided by (used in)			
Operating activities	$323,457	$324,629	$316,971
Investing activities	$(401,147)	$(349,278)	$11,169
Financing activities	$91,067	$17,028	$(371,446)

2014 Compared to 2013

Operating Activities:

Net cash provided by operating activities was $1.2 million lower than in 2013 primarily attributable to:

- Cash earnings (income from continuing operations plus non-cash adjustments) were $44 million higher than prior year;

- Net outflow from operating assets and liabilities of continuing operations were $49 million higher than prior year, primarily attributable to:

  * Increased working capital requirements of approximately $39 million resulting from higher commodity prices experienced in 2014 which created an increase in fuel cost adjustments recorded in regulatory assets at our Electric and Gas Utilities;

  * Increase in accounts receivable of approximately $17 million as a result of increased revenue and increased commodity costs in 2014;

* Receipt in 2013 of approximately $8.4 million from a government grant relating to the Busch Ranch Wind Project.

- A $10 million contribution in 2014 to our defined benefit plans compared to $13 million in 2013; and

- 2013 included cash outflows from operating activities of $1.0 million for post-closing adjustments resulting from the sale of our Energy Marketing segment in 2012.

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Investing Activities:

Net cash used in investing activities was $401 million in 2014, which was an increase in outflows of $52 million from 2013 primarily due to the following:

- In 2014, we had higher capital expenditures with an increase of $44 million primarily due the increase at our Oil and Gas segment.

Financing Activities:

Net cash provided by financing activities was $91 million in 2014, which was an increase in inflow of $74 million from 2013 primarily due to the following:

- In 2014, Black Hills Power and Cheyenne Light sold $160 million of first mortgage bonds in a private placement to provide permanent financing for Cheyenne Prairie;

- In 2014, we repaid $12 million of Black Hills Power's pollution control bonds;

- In 2014, we received $22 million from the sale of an asset at our Power Generation segment. Under GAAP, this transaction did not qualify as the sale of an asset and the proceeds are presented as a financing activity;

- In 2014, net cash payments on our revolving credit facility increased $44 million over 2013, in addition to the 2013 revolving credit facility payments described below;

- In 2013, we re-paid $250 million senior unsecured notes plus a make-whole premium of approximately $8.5 million, paid off the Black Hills Wyoming project debt for approximately $96 million with settlement of the associated interest rate swaps for approximately $8.5 million, repaid $55 million on Revolving Credit Facility and settled the de-designated interest rate swaps for approximately $64 million with proceeds from issuance of a senior unsecured notes for $525 million;

- In 2013, we entered into a long-term Corporate term loan for $275 million which was primarily used to repay the $100 million long-term term loan, the $150 million short-term term loan and a portion of the Revolving Credit Facility; and

- Cash dividends on common stock of $70 million were paid in 2014 compared to $68 million paid in 2013.

2013 Compared to 2012

Operating Activities:

Net cash provided by operating activities was $7.7 million higher than in 2012 primarily attributable to:

- Cash earnings (income from continuing operations plus non-cash adjustments) were $24 million higher than prior year;

- Net outflow from operating assets and liabilities of continuing operations were $14 million higher than prior year. The variance primarily related to increased natural gas inventory, a decrease in accounts payable of approximately $9.0 million due to the expiration of Colorado Electric's contract with PSCo at December 31, 2011, the return of cash collateral from our de-designated interest rate swaps of $6.0 million and other normal working capital changes;

- A $13 million contribution in 2013 to our defined benefit plans compared to $25 million in 2012; and
- 2013 included cash outflows from operating activities of $0.9 million for post-closing adjustments resulting from the sale of our Energy Marketing segment in 2012 compared to 2012, which included a $21 million cash inflow from operating activities in our Energy Marketing segment.

Investing Activities:

Net cash used in investing activities was $349 million in 2013, which was an increase in outflows of $360 million from 2012 primarily due to the following:

- In 2012, proceeds from sale of assets was $254 million which included $228 million from the sale of a majority of our Williston Basin assets by our Oil and Gas segment and $25 million from the partial sale of the Busch Ranch Wind project;

- In 2012, we received proceeds of $108 million from the sale of Enserco; and

- In 2013, we had comparable capital expenditures to 2012, with an increase of $5.6 million primarily due to the construction of Cheyenne Prairie.

Financing Activities:

Cash provided by financing activities was $17 million in 2013, which was an increase in inflow of $388 million from 2012 primarily due to the following:

- In 2013, we re-paid $250 million senior unsecured notes plus a make-whole premium of approximately $8.5 million, paid off the Black Hills Wyoming project debt for approximately $96 million with settlement of the associated interest rate swaps for approximately $8.5 million, repaid $55 million on Revolving Credit Facility and settled the de-designated interest rate swaps for approximately $64 million with proceeds from issuance of a senior unsecured notes for $525 million;

- In 2013, we entered into a long-term Corporate term loan for $275 million which was primarily used to repay the $100 million long-term term loan, the $150 million short-term term loan and a portion of the Revolving Credit Facility;

- In 2012, we repaid our $225 million senior unsecured 6.5% notes with proceeds from the sale of Williston Basin assets and Black Hills Power repaid its $6.5 million Pollution Control Revenue Bonds. The redemption of the notes required a make-whole provision payment of $7.1 million;

- In 2012, we repaid short-term borrowings from proceeds from the sale of Enserco partially offset by the use of short-term borrowings to fund the construction of Cheyenne Prairie; and

- Cash dividends on common stock of $68 million were paid in 2013 compared to $65 million paid in 2012.

CAPITAL EXPENDITURES

Capital expenditures are a substantial portion of our cash requirements each year and we continue to forecast a robust capital expenditure program during the next three years.

Historically, a significant portion of our capital expenditures relate primarily to assets that may be included in utility rate base, and if considered prudent by regulators, can be recovered from our utility customers. Those capital expenditures also earn a rate of return authorized by the commissions in the jurisdictions in which we operate and are subject to rate agreements. During 2014, our Electric Utilities' capital expenditures included the completion of Cheyenne Prairie and improvements to generating stations, transmission and distribution lines. Capital expenditures associated with our Gas Utilities are primarily to improve or expand the existing gas distribution network. In addition to our utility capital expenditures, we allocate a portion of our capital budget to Non-regulated operations with specific focus on our oil and gas drilling program. We believe that cash generated from operations and borrowing on our existing Revolving Credit Facility will be adequate to fund ongoing capital expenditures.

Historical Capital Requirements

Our primary capital requirements for the three years ended December 31 were as follows (in thousands):

	2014	2013	2012
Property additions: [a]			
Utilities -			
Electric Utilities [b]	$193,199	$222,262	$167,263
Gas Utilities	70,528	63,205	45,711
Non-regulated Energy -			
Power Generation	2,379	13,533	5,547
Coal Mining	6,676	5,528	13,420
Oil and Gas [c]	109,439	64,687	107,839
Corporate	9,046	10,319	7,376
Capital expenditures for continuing operations	391,267	379,534	347,156
Discontinued operations investing activities	—	—	824
Total expenditures for property, plant and equipment	391,267	379,534	347,980
Common stock dividends	69,636	67,587	65,262
Maturities/redemptions of long-term debt	12,200	445,906	240,077
	$473,103	$893,027	$653,319

(a) Includes accruals for property, plant and equipment.
(b) 2014 and 2013 include costs relating to Cheyenne Prairie which began construction in the spring of 2013; and 2012 included construction of our 50% ownership in the Busch Ranch Wind Project.
(c) Increase in 2014 expenditures was due to drilling and completion delays experienced in 2013.

Forecasted Capital Expenditure Requirements

Our primary capital expenditure requirements for the three years ended December 31 are expected to be as follows (in thousands):

	2015	2016	2017
Utilities:			
Electric Utilities	$229,300	$225,400	$135,600
Gas Utilities	83,600	60,100	71,800
Cost of Service Gas	—	40,000	50,000
Non-regulated Energy:			
Power Generation	8,000	2,000	2,600
Coal Mining	7,000	6,000	6,600
Oil and Gas	123,000	122,000	120,000
Corporate	6,100	1,500	3,600
	$457,000	$457,000	$390,200

We continue to evaluate potential future acquisitions and other growth opportunities which are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the estimates identified above.

CREDIT RATINGS AND COUNTERPARTIES

Financing for operational needs and capital expenditure requirements not satisfied by operating cash flows depends upon the cost and availability of external funds through both short and long-term financing. The inability to raise capital on favorable terms could negatively affect the Company's ability to maintain or expand its businesses. Access to funds is dependent upon factors such as general economic and capital market conditions, regulatory authorizations and policies, the company's credit ratings, cash flows from routine operations and the credit ratings of counterparties. After assessing the current operating performance, liquidity and credit ratings of the Company, management believes that the Company will have access to the capital markets at prevailing market rates for companies with comparable credit ratings. BHC notes that credit ratings are not recommendations to buy, sell, or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating.

The following table represents the credit ratings, outlook and risk profile of BHC at December 31, 2014:

Rating Agency	Senior Unsecured Rating	Outlook
S&P	BBB	Stable
Moody's [(a)]	Baa1	Stable
Fitch [(b)]	BBB+	Stable

(a) On January 30, 2014, Moody’s upgraded the BHC credit rating to Baa1 with a Stable outlook.
(b) On June 13, 2014, Fitch upgraded the BHC credit rating to BBB+ with a Stable outlook.

Our fees and interest payments under various corporate debt agreements are based on the higher credit rating of S&P or Moody’s. If either S&P or Moody’s downgraded our senior unsecured debt, we may be required to pay additional fees and incur higher interest rates under current bank credit agreements.

The following table represents the credit ratings of Black Hills Power at December 31, 2014:

Rating Agency	Senior Secured Rating
S&P	A-
Moody's *	A1
Fitch **	A

* On January 30, 2014, Moody’s upgraded the BHP credit rating to A1 with a Stable outlook.
** On June 13, 2014, Fitch upgraded the BHP credit rating to A with a Stable outlook.

We do not have any trigger events (i.e., an acceleration of repayment of outstanding indebtedness, an increase in interest costs, or the posting of additional cash collateral) tied to our stock price and have not executed any transactions that require us to issue equity based on our credit ratings or other trigger events.

CONTRACTUAL OBLIGATIONS AND OTHER COMMITMENTS

Contractual Obligations

In addition to our capital expenditure programs, we have contractual obligations and other commitments that will need to be funded in the future. The following information summarizes our cash obligations and commercial commitments at December 31, 2014. Actual future obligations may differ materially from these estimated amounts (in thousands):

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Long-term debt[(a)(b)]	$1,544,855	$275,000	$—	$—	$1,269,855
Unconditional purchase obligations[(c)]	694,999	183,116	322,583	150,181	39,119
Operating lease obligations[(d)]	21,055	9,962	5,726	2,709	2,658
Other long-term obligations[(e)]	47,386	—	—	—	47,386
Employee benefit plans[(f)]	158,521	15,081	47,595	32,030	63,815
Liability for unrecognized tax benefits in accordance with accounting guidance for uncertain tax positions [(g)]	32,193	—	10,357	4,010	17,826
Notes payable	75,000	75,000	—	—	—
Total contractual cash obligations[(h)]	$2,574,009	$558,159	$386,261	$188,930	$1,440,659

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(a) Long-term debt amounts do not include discounts or premiums on debt.

(b) The following amounts are estimated for interest payments over the next five years based on a mid-year retirement date for long-term debt expiring during the identified period and are not included within the long-term debt balances presented: $68 million in 2015, $65 million in 2016, $65 million in 2017, $65 million in 2018 and $60 million in 2019. Estimated interest payments on variable rate debt are calculated by utilizing the applicable rates as of December 31, 2014.

(c) Unconditional purchase obligations include the energy and capacity costs associated with our PPAs, capacity and certain transmission, gas purchases, gas transportation and storage agreements, and gathering commitments for our Oil and Gas segment. The energy charge under the PPAs and the commodity price under the gas purchase contracts are variable costs, which for purposes of estimating our future obligations, were based on costs incurred during 2014 and price assumptions using existing prices at December 31, 2014. Our transmission obligations are based on filed tariffs as of December 31, 2014. A portion of our gas purchases are purchased under evergreen contracts and therefore, for purposes of this disclosure, are carried out for 60 days. The gathering commitments for our Oil and Gas segment are described in Part I, Delivery Commitments, of this Annual Report filed on Form 10-K.

(d) Includes operating leases associated with several office buildings, warehouses and call centers, equipment and vehicles.

(e) Includes estimated asset retirement obligations associated with our Electric Utilities, Gas Utilities, Coal Mining and Oil and Gas segments as discussed in Note 7 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

(f) Represents both estimated employer contributions to Defined Benefit Pension Plans and payments to employees for the Non-Pension Defined Benefit Postretirement Healthcare Plans and the Supplemental Non-Qualified Defined Benefit Plans through the year 2024.

(g) Years 1-3 include an estimated reversal of approximately $6.2 million associated with the gain deferred from the tax treatment related to the IPP Transaction and the Aquila Transaction.

(h) Amounts in the table exclude: (1) any obligation that may arise from our derivatives, including interest rate swaps and commodity related contracts that have a negative fair value at December 31, 2014. These amounts have been excluded as it is impractical to reasonably estimate the final amount and/or timing of any associated payments; and (2) a portion of our gas purchases are hedged. These hedges are in place to reduce our customers' underlying exposure to commodity price fluctuations. The impact of these hedges is not included in the above table.

Off-Balance Sheet Commitments

Guarantees

We have entered into various off-balance sheet commitments in the form of guarantees and letters of credit. We provide various guarantees supporting certain of our subsidiaries under specified agreements or transactions. At December 31, 2014, we had outstanding guarantees as indicated in the table below. For more information on these guarantees, see Note 19 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

We had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2014	Year Expiring
Indemnification for subsidiary reclamation/surety bonds [(a)]	$63,900	Ongoing
	$63,900	

(a) We have guarantees in place for reclamation and surety bonds for our subsidiaries. The guarantees were entered into in the normal course of business. To the extent liabilities are incurred as a result of activities covered by the surety bonds, such liabilities are included in our Consolidated Balance Sheets.

During the second quarter of 2014, guarantees of Black Hills Utility Holdings' payment obligations up to $70 million arising from commodity transactions for natural gas supply were removed, primarily due to improvement of the corporate credit rating, as well as the conversion of certain guarantees to letters of credit.

Letters of Credit

Letters of credit reduce the borrowing capacity available on our corporate Revolving Credit Facility. We had $35 million in letters of credit issued under our Revolving Credit Facility at December 31, 2014.

Market Risk Disclosures

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operations of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures.

Market risk is the potential loss that may occur as a result of an adverse change in market price or rate. We are exposed to the following market risks, including, but not limited to:

- Commodity price risk associated with our natural long position with crude oil and natural gas reserves and production and fuel procurement for certain of our gas-fired generation assets; and
- Interest rate risk associated with our variable rate debt and our other short-term and long-term debt instruments as described in Notes 5 and 6 of our Notes to Consolidated Financial Statements.

Our exposure to these market risks is affected by a number of factors including the size, duration and composition of our energy portfolio, the absolute and relative levels of interest rates and commodity prices, the volatility of these prices and rates and the liquidity of the related interest rate and commodity markets.

The Black Hills Corporation Risk Policies and Procedures have been approved by our Executive Risk Committee and reviewed by the Audit Committee of our Board of Directors. These policies relate to numerous matters including governance, control infrastructure, authorized commodities and trading instruments, prohibited activities and employee conduct. The Executive Risk Committee, which includes senior level executives, meets on a regular basis to review our business and credit activities and to ensure that these activities are conducted within the authorized policies.

Utilities Group

We produce, purchase and distribute power in four states, and purchase and distribute natural gas in five states. All of our utilities have GCA provisions that allow them to pass the prudently-incurred cost of gas through to the customer. To the extent that gas prices are higher or lower than amounts in our current billing rates, adjustments are made on a periodic basis to “true-up” billed amounts to match the actual natural gas cost we incurred. In South Dakota, Colorado, Wyoming and Montana, we have a mechanism for our regulated electric utilities that serves a purpose similar to the GCAs for our regulated gas utilities. To the extent that our fuel and purchased power costs are higher or lower than the energy cost built into our tariffs, the difference (or a portion thereof) is passed through to the customer. These adjustments are subject to periodic prudence reviews by the state utility commissions.

The operations of our utilities, including power purchase arrangements where our utilities must provide the generation fuel (tolling agreements), expose our utility customers to volatility in natural gas prices; therefore, as allowed or required, by state utility commissions, we have entered into commission-approved hedging programs utilizing natural gas futures, options and basis swaps to reduce our customers’ underlying exposure to these fluctuations. These transactions are considered derivatives, and in accordance with accounting standards for derivatives and hedging, mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets, net of balance sheet offsetting as permitted by GAAP. Unrealized and realized gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in the accompanying Consolidated Balance Sheets in accordance with the state utility commission guidelines. Accordingly, the hedging activity is recognized in the Consolidated Statements of Income (Loss) or the Consolidated Statements of Comprehensive Income (Loss) when the related costs are recovered through our rates.

The fair value of our Utilities Group derivative contracts at December 31 is summarized below (in thousands):

	2014	2013
Net derivative liabilities	$(16,914)	$(6,071)
Cash collateral	20,007	10,123
	$3,093	$4,052

Oil and Gas

Oil and Gas Exploration and Production

We produce natural gas, NGLs and crude oil through our exploration and production activities. Our natural long positions, or unhedged open positions, result in commodity price risk and variability to our cash flows.

To mitigate commodity price risk and preserve cash flows, we primarily use exchange traded futures and related options to hedge portions of our crude oil and natural gas production. We elect hedge accounting on these instruments. Our hedging policy allows our natural gas and crude oil production from proven producing reserves to be hedged for a period up to three years in the future. Some of our commodity contracts are subject to master netting agreements, where our asset and liability positions include cash collateral that allow us to settle positive and negative positions.

We have entered into agreements to hedge a portion of our estimated 2015 and 2016 natural gas and crude oil production from the Oil and Gas segment. The hedge agreements in place as of December 31, 2014, are as follows:

Natural Gas

	For the Three Months Ended				
	March 31,	June 30,	September 30,	December 31,	Total Year
2015					
Swaps - MMBtu	1,215,000	1,180,000	955,000	1,000,000	4,350,000
Weighted Average Price per MMBtu	$4.24	$4.03	$4.00	$4.04	$4.08
2016					
Swaps - MMBtu	585,000	557,500	545,000	545,000	2,232,500
Weighted Average Price per MMBtu	$3.91	$3.98	$4.08	$3.90	$3.97

Crude Oil

	For the Three Months Ended				
	March 31,	June 30,	September 30,	December 31,	Total Year
2015					
Swaps - Bbls	55,500	51,000	42,000	36,000	184,500
Weighted Average Price per Bbl	$89.98	$87.84	$88.18	$87.92	$88.58
2016					
Swaps - Bbls	39,000	39,000	36,000	36,000	150,000
Weighted Average Price per Bbl	$84.55	$84.55	$84.55	$84.55	$84.55

The fair value of our Oil and Gas segment's derivative contracts at December 31 is summarized below (in thousands):

	2014	2013
Net derivative asset (liability)	$14,684	$(869)
Cash collateral (received) paid	(10,292)	2,500
	$4,392	$1,631

Wholesale Power

A potential risk related to power sales is the price risk arising from the sale of wholesale power that exceeds our generating capacity. These potential short positions can arise from unplanned plant outages or from unanticipated load demands. To manage such risk, we restrict wholesale off-system sales to amounts by which our anticipated generating capabilities and purchased power resources exceed our anticipated load requirements plus a required reserve margin.

Financing Activities

We engage in activities to manage risks associated with changes in interest rates. We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations. At December 31, 2014, we had $75 million of notional amount floating-to-fixed interest rate swaps, with a maximum term of 2 years. These swaps have been designated as cash flow hedges in accordance with accounting standards for derivatives and hedges and accordingly their mark-to-market adjustments are recorded in Accumulated other comprehensive loss on the accompanying Consolidated Balance Sheets.

Further details of the swap agreements are set forth in Note 8 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

On December 31, 2014 and December 31, 2013, our interest rate swaps and related balances were as follows (dollars in thousands):

	Notional	Weighted Average Fixed Interest Rate	Maximum Terms in Years	Current Liabilities, net of Cash Collateral	Non-current Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)	Pre-tax Unrealized Gain (Loss)
December 31, 2014							
Interest rate swaps	$75,000	4.97 %	2	$3,340	$2,680	$ (6,020)	$—
December 31, 2013							
Interest rate swaps	$75,000	4.97 %	3	$3,474	$5,614	$ (9,088)	$—

Based on December 31, 2014 market interest rates and balances, a loss of approximately $3.3 million would be realized and reported in pre-tax earnings during the next 12 months. Estimated and realized losses will likely change during the next twelve months as market interest rates change.

The table below presents principal amounts and related weighted average interest rates by year of maturity for our long-term debt obligations, including current maturities (dollars in thousands):

	2015	2016	2017	2018	2019	Thereafter	Total
Long-term debt							
Fixed rate[(a)]	$—	$—	$—	$—	$—	$1,250,000	$1,250,000
Average interest rate [(b)]	— %	— %	— %	— %	— %	5.2 %	5.2 %
Variable rate	$275,000	$—	$—	$—	$—	$19,855	$294,855
Average interest rate [(b)]	1.31 %	— %	— %	— %	— %	0.18 %	1.24 %
Total long-term debt	$275,000	$—	$—	$—	$—	$1,269,855	$1,544,855
Average interest rate [(b)]	1.31 %	— %	— %	— %	— %	5.12 %	4.44 %

(a) Excludes unamortized premium or discount.
(b) The average interest rates do not include the effect of interest rate swaps.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty. We have adopted the Black Hills Corporation Credit Policy that establishes guidelines, controls and limits to manage and mitigate credit risk within risk tolerances established by the Board of Directors. In addition, our Executive Risk Committee, which includes senior executives, meets on a regular basis to review our credit activities and to monitor compliance with the adopted policies.

We seek to mitigate our credit risk by conducting a majority of our business with investment grade companies, setting tenor and credit limits commensurate with counterparty financial strength, obtaining netting agreements and securing our credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit and other security agreements.

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer’s current creditworthiness, as determined by our review of their current credit information. We maintain a provision for estimated credit losses based upon our historical experience and any specific customer collection issue that we have identified. While most credit losses have historically been within our expectations and provisions established, we cannot provide assurance that we will continue to experience the same credit loss rates that we have in the past, or that an investment grade counterparty will not default sometime in the future.

At December 31, 2014, our credit exposure included a $0.6 million exposure to a non-investment grade rural electric utility cooperative. The remainder of our credit exposure was concentrated primarily among retail utility customers, investment grade companies, municipal cooperatives and federal agencies.

New Accounting Pronouncements

See Note 1 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for information on new accounting standards adopted in 2014 or pending adoption.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Management's Report on Internal Control over Financial Reporting

We are responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is a process designed 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.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.
Under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2014, based on the criteria set forth in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on our evaluation, we have concluded that our internal control over financial reporting was effective as of December 31, 2014.

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of Black Hills Corporation's financial statements, has issued an attestation report on the effectiveness of Black Hills Corporation's internal control over financial reporting as of December 31, 2014. Deloitte & Touche LLP's report on Black Hills Corporation's internal control over financial reporting is included herein.

Black Hills Corporation

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Black Hills Corporation
Rapid City, South Dakota

We have audited the accompanying consolidated balance sheets of Black Hills Corporation and subsidiaries (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income (loss), common stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedule listed in the Index at Item 15. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes 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 Black Hills Corporation 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. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2014, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2015 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 24, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Black Hills Corporation
Rapid City, South Dakota

We have audited the internal control over financial reporting of Black Hills Corporation and subsidiaries (the "Company") as of December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2014 of the Company and our report dated February 24, 2015 expressed an unqualified opinion on those consolidated financial statements and financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 24, 2015

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

Year ended	December 31, 2014	December 31, 2013	December 31, 2012
	(in thousands, except per share amounts)		
Revenue:			
Utilities	$1,300,969	$1,191,133	$1,064,813
Non-regulated energy	92,601	84,719	109,071
Total revenue	1,393,570	1,275,852	1,173,884
Operating expenses:			
Utilities -			
Fuel, purchased power and cost of natural gas sold	581,782	492,147	407,066
Operations and maintenance	270,954	261,919	242,367
Non-regulated energy operations and maintenance	88,141	83,762	85,830
Gain on sale of operating assets	—	—	(29,129)
Depreciation, depletion and amortization	148,083	141,217	154,632
Impairment of long-lived assets	—	—	26,868
Taxes - property, production and severance	43,580	40,012	40,487
Other operating expenses	500	1,243	2,052
Total operating expenses	1,133,040	1,020,300	930,173
Operating income	260,530	255,552	243,711
Other income (expense):			
Interest charges -			
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts and realized settlements on interest rate swaps)	(73,017)	(113,979)	(117,754)
Allowance for funds used during construction - borrowed	1,075	1,130	3,462
Capitalized interest	982	1,061	682
Unrealized gain (loss) on interest rate swaps, net	—	30,169	1,882
Interest income	1,925	1,723	1,957
Allowance for funds used during construction - equity	994	607	540
Other expense	(377)	(694)	(71)
Other income	2,065	1,971	2,486
Total other income (expense)	(66,353)	(78,012)	(106,816)
Income (loss) from continuing operations before earnings (loss) of unconsolidated subsidiaries and income taxes	194,177	177,540	136,895
Equity in earnings (loss) of unconsolidated subsidiaries	(1)	(86)	10
Income tax benefit (expense)	(65,395)	(61,608)	(48,400)
Income (loss) from continuing operations	128,781	115,846	88,505
Income (loss) from discontinued operations, net of tax	—	(884)	(6,977)
Net income (loss) available for common stock	$128,781	$114,962	$81,528
Earnings (loss) per share of common stock:			
Earnings (loss) per share, Basic -			
Income (loss) from continuing operations, per share	$2.90	$2.62	$2.02
Income (loss) from discontinued operations, per share	—	(0.02)	(0.16)

Total income (loss) per share, Basic	$2.90	$2.60	$1.86
Earnings (loss) per share, Diluted -			
Income (loss) from continuing operations, per share	$2.89	$2.61	$2.01
Income (loss) from discontinued operations, per share	—	(0.02)	(0.16)
Total income (loss) per share, Diluted	$2.89	$2.59	$1.85
Weighted average common shares outstanding:			
Basic	44,394	44,163	43,820
Diluted	44,598	44,419	44,073

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

Years ended (in thousands)	December 31, 2014	December 31, 2013	December 31, 2012
Net income (loss) available for common stock	$128,781	$114,962	$81,528
Other comprehensive income (loss), net of tax:			
Benefit plan liability adjustments - net gain (loss) (net of tax of $5,004, $(3,813) and $296, respectively)	(10,590)	8,237	(542)
Benefit plan liability adjustments - prior service (costs) (net of tax of $(17), $185 and $86, respectively)	237	(406)	(157)
Reclassification adjustment of benefit plan liability - net gain (loss) (net of tax of $(348), $(971) and $0, respectively)	646	1,820	—
Reclassification adjustment of benefit plan liability - prior service cost (net of tax of $76, $88 and $0, respectively)	(141)	(165)	—
Fair value adjustment on derivatives designated as cash flow hedges (net of tax of $(5,239), $(2,445) and $887, respectively)	8,906	4,534	(1,268)
Reclassification adjustment of cash flow hedges settled and included in net income (loss) (net of tax of $(2,344), $(2,016) and $534, respectively)	3,320	4,046	(643)
Other comprehensive income (loss), net of tax	2,378	18,066	(2,610)
Comprehensive income (loss)	$131,159	$133,028	$78,918

See Note 15 for additional disclosures related to Comprehensive Income.

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS

	As of December 31, 2014	December 31, 2013
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$21,218	$7,841
Restricted cash and equivalents	2,056	2
Accounts receivable, net	189,992	177,573
Materials, supplies and fuel	91,191	88,478
Derivative assets, current	—	717
Income tax receivable, net	2,053	1,460
Deferred income tax assets, net, current	48,288	18,889
Regulatory assets, current	74,396	24,451
Other current assets	24,842	25,877
Total current assets	454,036	345,288
Investments	17,294	16,697
Property, plant and equipment	4,563,400	4,259,445
Less accumulated depreciation and depletion	(1,324,025)	(1,269,148)
Total property, plant and equipment, net	3,239,375	2,990,297
Other assets:		
Goodwill	353,396	353,396
Intangible assets, net	3,176	3,397
Derivative assets, non-current	—	—
Regulatory assets, non-current	183,443	138,197
Other assets, non-current	29,086	27,906
Total other assets, non-current	569,101	522,896
TOTAL ASSETS	$4,279,806	$3,875,178

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS
(Continued)

	As of December 31, 2014	December 31, 2013
	(in thousands, except share amounts)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$124,139	$130,416
Accrued liabilities	170,115	151,277
Derivative liabilities, current	3,340	3,474
Regulatory liabilities, current	3,687	10,727
Notes payable	75,000	82,500
Current maturities of long-term debt	275,000	—
Total current liabilities	651,281	378,394
Long-term debt, net of current maturities	1,267,589	1,396,948
Deferred credits and other liabilities:		
Deferred income tax liabilities, net, non-current	523,716	432,287
Derivative liabilities, non-current	2,680	5,614
Regulatory liabilities, non-current	145,144	109,429
Benefit plan liabilities	158,966	111,479
Other deferred credits and other liabilities	154,406	133,279
Total deferred credits and other liabilities	984,912	792,088
Commitments and contingencies (See Notes 5, 6, 7, 8, 13, 17, 18 and 19)		
Stockholders' equity:		
Common stock $1 par value; 100,000,000 shares authorized; issued: 44,714,072 and 44,550,239 shares, respectively	44,714	44,550
Additional paid-in capital	748,840	742,344
Retained earnings	599,389	540,244
Treasury stock at cost - 42,226 and 50,877 shares, respectively	(1,875)	(1,968)
Accumulated other comprehensive income (loss)	(15,044)	(17,422)
Total stockholders' equity	1,376,024	1,307,748
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$4,279,806	$3,875,178

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended	December 31, 2014	December 31, 2013	December 31, 2012
	(in thousands)		
Operating activities:			
Net income available for common stock	$128,781	$114,962	$81,528
(Income) loss from discontinued operations, net of tax	—	884	6,977
Income (loss) from continuing operations	128,781	115,846	88,505
Adjustments to reconcile income (loss) from continuing operations to net cash provided by operating activities:			
Depreciation, depletion and amortization	148,083	141,217	154,632
Deferred financing cost amortization	2,127	6,763	5,555
Impairment of long-lived assets	—	—	26,868
Gain on sale of operating assets	—	—	(29,129)
Stock compensation	9,329	12,595	8,271
Unrealized (gain) loss on interest rate swaps, net	—	(30,169)	(1,882)
Deferred income taxes	69,002	63,784	39,716
Employee benefit plans	14,814	22,194	20,973
Other adjustments, net	14,415	9,826	4,929
Change in certain operating assets and liabilities:			
Materials, supplies and fuel	(4,563)	(5,770)	6,343
Accounts receivable, unbilled revenues and other current assets	(65,091)	(13,921)	13,739
Accounts payable and other current liabilities	16,027	15,336	(10,713)
Contributions to defined benefit pension plans	(10,200)	(12,500)	(25,350)
Other operating activities, net	733	312	(6,670)
Net cash provided by operating activities of continuing operations	323,457	325,513	295,787
Net cash provided by (used in) operating activities of discontinued operations	—	(884)	21,184
Net cash provided by operating activities	323,457	324,629	316,971
Investing activities:			
Property, plant and equipment additions	(398,494)	(354,749)	(349,129)
Proceeds from sale of assets	—	—	253,791
Other investing activities	(2,653)	5,471	(180)
Net cash provided by (used in) investing activities of continuing operations	(401,147)	(349,278)	(95,518)
Proceeds from sale of business operations	—	—	107,511
Net cash provided by (used in) investing activities of discontinued operations	—	—	(824)
Net cash provided by (used in) investing activities	(401,147)	(349,278)	11,169
Financing activities:			
Dividends paid on common stock	(69,636)	(67,587)	(65,262)
Common stock issued	3,251	4,354	4,726
Short-term borrowings - issuances	396,250	337,650	203,753
Short-term borrowings - repayments	(403,750)	(532,150)	(271,753)
Long-term debt - issuance	160,000	800,000	—
Long-term debt - repayments	(12,200)	(445,906)	(240,077)

De-designated interest rate swap settlement	—	(63,939)	—
Other financing activities	17,152	(15,394)	(2,833)
Net cash provided by (used in) financing activities of continuing operations	91,067	17,028	(371,446)
Net cash provided by (used in) financing activities of discontinued operations	—	—	—
Net cash provided by (used in) financing activities	91,067	17,028	(371,446)
Net change in cash and cash equivalents	13,377	(7,621)	(43,306)
Cash and cash equivalents beginning of year *	7,841	15,462	58,768
Cash and cash equivalents end of year	$21,218	$7,841	$15,462

* Cash and cash equivalents include cash of discontinued operations of $37 million at December 31, 2011.

See Note 16 for supplemental disclosure of cash flow information.

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

	Common Stock		Treasury Stock					
(in thousands except share)	Shares	Value	Shares	Value	Additional Paid in Capital	Retained Earnings	AOCI	Total
Balance at December 31, 2011	43,957,502	$43,958	32,766	$(970)	$722,623	$476,603	$(32,878)	$1,209,336
Net income (loss) available for common stock	—	—	—	—	—	81,528	—	81,528
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	(2,610)	(2,610)
Dividends on common stock	—	—	—	—	—	(65,262)	—	(65,262)
Share-based compensation	219,946	220	39,016	(1,275)	7,095	—	—	6,040
Tax effect of share-based compensation	—	—	—	—	117	—	—	117
Dividend reinvestment and stock purchase plan	100,741	100	—	—	3,282	—	—	3,382
Other stock transactions	—	—	—	—	(22)	—	—	(22)
Balance at December 31, 2012	44,278,189	$44,278	71,782	$(2,245)	$733,095	$492,869	$(35,488)	$1,232,509
Net income (loss) available for common stock	—	—	—	—	—	114,962	—	114,962
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	18,066	18,066
Dividends on common stock	—	—	—	—	—	(67,587)	—	(67,587)
Share-based compensation	190,172	190	(20,905)	277	5,400	—	—	5,867
Tax effect of share-based compensation	—	—	—	—	410	—	—	410
Dividend reinvestment and stock purchase plan	66,878	67	—	—	3,062	—	—	3,129
Other stock transactions	15,000	15	—	—	377	—	—	392
Balance at December 31, 2013	44,550,239	$44,550	50,877	$(1,968)	$742,344	$540,244	$(17,422)	$1,307,748
Net income (loss) available for common stock	—	—	—	—	—	128,781	—	128,781
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	2,378	2,378
Dividends on common stock	—	—	—	—	—	(69,636)	—	(69,636)
Share-based compensation	111,507	112	(8,651)	93	4,210	—	—	4,415
Tax effect of share-based compensation	—	—	—	—	(499)	—	—	(499)
Dividend reinvestment and stock purchase plan	52,326	52	—	—	2,826	—	—	2,878
Other stock transactions	—	—	—	—	(41)	—	—	(41)
Balance at December 31, 2014	44,714,072	$44,714	42,226	$(1,875)	$748,840	$599,389	$(15,044)	$1,376,024

Dividends per share paid were $1.56, $1.52 and $1.48 for the years ended December 31, 2014, 2013 and 2012, respectively.

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2014, 2013 and 2012

(1) BUSINESS DESCRIPTION AND SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Corporation is a diversified energy company headquartered in Rapid City, South Dakota. We are a holding company that, through our subsidiaries, operates in two primary business groups: Utilities and Non-regulated Energy.

The Utilities Group includes our Electric Utilities and Gas Utilities segments. Electric Utilities include the operating results of the regulated electric utility operations of Black Hills Power and Colorado Electric and the electric and natural gas utility operations of Cheyenne Light, which supply regulated electric utility services to areas in South Dakota, Wyoming, Colorado and Montana and natural gas utility services to Cheyenne, Wyoming and vicinity. Gas Utilities consist of the operating results of the regulated natural gas utility operations of Colorado Gas, Nebraska Gas, Iowa Gas and Kansas Gas.

The Non-regulated Energy Group includes our Power Generation, Coal Mining and Oil and Gas segments. Power Generation, which is conducted through Black Hills Electric Generation and its subsidiaries, engages in independent power generation activities in Wyoming and Colorado. Coal Mining, which is conducted through WRDC, engages in coal mining activities located near Gillette, Wyoming. Oil and Gas, which is conducted through BHEP and its subsidiaries, engages in crude oil and natural gas exploration and production activities in Colorado, Louisiana, Montana, Oklahoma, New Mexico, North Dakota, Wyoming, Texas and California. These businesses are aggregated for reporting purposes as Non-regulated Energy.

On February 29, 2012, we sold Enserco, our Energy Marketing segment, which resulted in this segment being reclassified as discontinued operations. See Note 21 for additional information.

For further descriptions of our reportable business segments, see Note 4.

Use of Estimates and Basis of Presentation

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Changes in facts and circumstances or additional information may result in revised estimates and actual results could differ materially from those estimates.

Principles of Consolidation

The consolidated financial statements include the accounts of Black Hills Corporation and its wholly-owned and majority-owned and controlled subsidiaries. Investment in non-controlled entities over which we have the ability to exercise significant influence over operating and financial policies are accounted for using the equity method of accounting. In applying the equity method of accounting, the investments are initially recognized at cost and subsequently adjusted for our proportionate share of earnings and losses and distributions. Under this method, a proportionate share of pretax income is recorded as Equity earnings (loss) of unconsolidated subsidiaries. All inter-company balances and transactions have been eliminated in consolidation. For additional information on inter-company revenues, see Note 4.

Our Consolidated Statements of Income include operating activity of acquired companies beginning with their acquisition date. We use the proportionate consolidation method to account for our working interests in oil and gas properties and for our ownership interest in any jointly-owned electric utility generating facility, wind project or transmission tie and the BHEP gas processing plant. See Note 3 for additional information.

As a result of the sale of our Energy Marketing segment, amounts associated with this segment have been reclassified as discontinued operations on the accompanying Consolidated Financial Statements. See Note 21 for additional information.

Cash and Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Equivalents

We maintain cash accounts for various specified purposes. Therefore, we classify these amounts as restricted cash.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable for our Utilities Group primarily consists of sales to residential, commercial, industrial, municipal and other customers, all of which do not bear interest. These accounts receivable are stated at billed and unbilled amounts net of write-offs and allowance for doubtful accounts. Accounts receivable for our Non-regulated Energy Group consists of amounts due from sales of coal, crude oil and natural gas, electric energy and capacity.
We maintain an allowance for doubtful accounts which reflects our estimate of uncollectible trade receivables. We regularly review our trade receivable allowance by considering such factors as historical experience, credit worthiness, the age of the receivable balances and current economic conditions that may affect collectibility.

In specific cases where we are aware of a customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be affected. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of commodity prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible or the time allowed for dispute under the contract has expired.
We utilize master netting agreements which consist of an agreement between two parties who have multiple contracts with each other that provide for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim, or the obligation to return, cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty.

Following is a summary of accounts receivable as of December 31 (in thousands):

2014	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$59,714	$26,474	$(722)	$85,466
Gas Utilities	47,394	45,546	(781)	92,159
Power Generation	1,369	—	—	1,369
Coal Mining	3,151	—	—	3,151
Oil and Gas	5,305	—	(13)	5,292
Corporate	2,555	—	—	2,555
Total	$119,488	$72,020	$(1,516)	$189,992

2013	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$52,437	$23,823	$(666)	$75,594
Gas Utilities	49,162	41,195	(558)	89,799
Power Generation	1,722	—	—	1,722
Coal Mining	1,711	—	—	1,711
Oil and Gas	8,156	—	(13)	8,143
Corporate	604	—	—	604
Total	$113,792	$65,018	$(1,237)	$177,573

Revenue Recognition

Revenue is recognized when there is persuasive evidence of an arrangement with a fixed or determinable price and delivery has occurred or services have been rendered. Sales tax collected from our customers is recorded on a net basis (excluded from Revenue).

Utility revenues are based on authorized rates approved by the state regulatory agencies and the FERC. Revenues related to the sale, transmission and distribution of energy, and delivery of service are generally recorded when service is rendered or energy is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, our utilities accrue an estimate of the revenue since the latest billing. This estimate is calculated based upon several factors including billings through the last billing cycle in a month and prices in effect in our jurisdictions. Each month the estimated unbilled revenue amounts are trued-up and recorded in Accounts receivable, net on the accompanying Consolidated Balance Sheets.

For long-term non-regulated power sales agreements, revenue is recognized either in accordance with accounting standards for revenue recognition, or in accordance with accounting standards for leases, as appropriate. Under accounting standards for revenue recognition, revenue is generally recognized as the lesser of the amount billed or the average rate expected over the life of the agreement.

Natural gas and crude oil sales are recognized when the products are sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred and collectibility of the revenue is reasonably assured. Our Oil and Gas segment records its share of revenues based on production volumes and contracted sales prices. The sales price for natural gas, crude oil, condensate and NGLs is adjusted for transportation costs and other related deductions when applicable. The transportation costs and other deductions are based on contractual or historical data and do not require significant judgment.

Materials, Supplies and Fuel

The following amounts by major classification are included in Materials, supplies and fuel on the accompanying Consolidated Balance Sheets as of (in thousands):

	December 31, 2014	December 31, 2013
Materials and supplies	$49,555	$50,196
Fuel - Electric Utilities	6,637	6,213
Natural gas in storage held for distribution	34,999	32,069
Total materials, supplies and fuel	$91,191	$88,478

Materials and supplies represent parts and supplies for all of our business segments. Fuel - Electric Utilities represents oil, gas and coal on hand used to produce power. Natural gas in storage primarily represents gas purchased for use by our gas customers. All of our Materials, supplies and fuel are valued using weighted-average cost. The value of our natural gas in storage fluctuates with seasonal volume requirements of our business and the commodity price of natural gas.

Property, Plant and Equipment

Additions to property, plant and equipment are recorded at cost. Included in the cost of regulated construction projects is AFUDC, when applicable, which represents the approximate composite cost of borrowed funds and a return on equity used to finance a regulated utility project. We also capitalize interest, when applicable, on undeveloped leasehold costs and certain non-regulated construction projects. In addition, asset retirement costs associated with tangible long-lived regulated utility assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived regulated utility assets in the period incurred. The amounts capitalized are included in Property, plant and equipment on the accompanying Consolidated Balance Sheets.

The cost of regulated utility property, plant and equipment retired, or otherwise disposed of in the ordinary course of business, less salvage plus cost of removal, is charged to accumulated depreciation. Estimated removal costs associated with non-legal obligations related to our regulated properties are reclassified from accumulated depreciation and reflected as regulatory liabilities. Retirement or disposal of all other assets, except for crude oil and natural gas properties as described below, result in gains or losses recognized as a component of operating income. Ordinary repairs and maintenance of property, except as allowed under rate regulations, are charged to operations as incurred.

Depreciation provisions for property, plant and equipment are generally computed on a straight-line basis based on the applicable estimated service life of the various class of property. Capitalized coal mining costs and coal leases are amortized on a unit-of-production method based on volumes produced and estimated reserves. For certain non-utility power plant components, a unit-of-production methodology based on plant hours run is used.

Oil and Gas Operations

We account for our oil and gas activities under the full cost method. Under the full cost method, costs related to acquisition, exploration and estimated future expenditures to be incurred in developing proved reserves as well as estimated reclamation and abandonment costs, net of estimated salvage values are capitalized. These costs are amortized using a unit-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonment of properties, are typically treated as adjustments to the cost of the properties with no gain or loss recognized. However, we recognized a gain on the sale of a majority of our Williston Basin assets in 2012. See Note 21 for further discussion.

Costs directly associated with unproved properties and major development projects, if any, are excluded from the costs to be amortized. These excluded costs are subsequently included within the costs to be amortized when it is determined whether or not proved reserves can be assigned to the properties. The properties excluded from the costs to be amortized are assessed for impairment at least annually and any amount of impairment is added to the costs to be amortized. These costs are generally expected to be included in costs to be amortized within the term of the underlying lease agreement which varies in length.

Under the full cost method, net capitalized costs, less accumulated amortization and related deferred income taxes, are subject to a ceiling test which limits the pooled costs to the aggregate of the discounted value of future net revenue attributable to proved natural gas and crude oil reserves using a discount rate defined by the SEC, plus the lower of cost or market value of unevaluated properties. Future net cash flows are estimated based on SEC-defined end-of-period commodity prices adjusted for contracted price changes and held constant for the life of the reserves. An average price is calculated using the price at the first day of each month for each of the preceding 12 months. If the net capitalized costs exceed the full cost “ceiling” at period end, a permanent non-cash write-down would be charged to earnings in that period. As a result of lower natural gas prices, we recorded a non-cash ceiling test impairment of oil and gas long-lived assets included in the Oil and Gas segment in 2012. No ceiling test write-down was recorded in

2014 or 2013. See Note 12 for additional information.

The SEC definition of “reliable technology” permits the use of any reliable technology to establish reserve volumes in addition to those established by production and flow test data. This definition allows, but does not require us, to calculate PUDs to be booked at more than one location away from a producing well. We elected to include PUDs of only one location away from a producing well in our volume reserve estimate. See information on our oil and gas drilling activities in Note 20.

Companies are permitted but not required to disclose probable and possible reserves. We have elected not to report on these additional reserve categories.

Goodwill and Intangible Assets

Goodwill and intangible assets with indefinite lives are not amortized but the carrying values are reviewed upon an indicator of impairment or at least annually. Intangible assets with a finite life continue to be amortized over their estimated useful lives. We perform this annual review of goodwill and indefinite lived intangible assets as of November 30 each year (or more frequently if impairment indicators arise).

We performed our annual goodwill impairment tests as of November 30, 2014. We estimated the fair value of the goodwill using discounted cash flow methodology, EBITDA multiple method and an analysis of comparable transactions. This analysis required the input of several critical assumptions, including future growth rates, cash flow projections, operating cost escalation rates, rates of return, a risk-adjusted discount rate, timing and level of success in regulatory rate proceedings, the cost of debt and equity capital and long-term earnings and merger multiples for comparable companies.

Goodwill at our Electric and Gas Utilities primarily arose from the acquisition of one regulated electric and four regulated gas utilities in the Aquila Transaction. This goodwill from the Aquila Transaction was allocated approximately $246 million, or 72%, to Colorado Electric and $94 million, or 28%, to the Gas Utilities. We believe that the goodwill amount reflects the value of the relatively stable, long-lived cash flows of the regulated gas utility business, considering the regulatory environment and market growth potential and the long-lived cash flow and rate base growth opportunities at our electric utility in Colorado. Goodwill balances were as follows (in thousands):

	Electric Utilities	Gas Utilities	Power Generation	Total
Ending balance at December 31, 2012	$250,487	$94,144	$8,765	$353,396
Additions (adjustments)	—	—	—	—
Ending balance at December 31, 2013	$250,487	$94,144	$8,765	$353,396
Additions (adjustments)	—	—	—	—
Ending balance at December 31, 2014	$250,487	$94,144	$8,765	$353,396

Our intangible assets represent easements, rights-of-way and trademarks and are amortized using a straight-line method based on estimated useful lives. The finite lived intangible assets are currently being amortized over 20 years. Changes to intangible assets for the years ended December 31, were as follows (in thousands):

	2014	2013	2012
Intangible assets, net, beginning balance	$3,397	$3,620	$3,843
Additions (adjustments)	—	—	—
Amortization expense*	(221)	(223)	(223)
Intangible assets, net, ending balance	$3,176	$3,397	$3,620

* Amortization expense for existing intangible assets is expected to be $0.2 million for each year of the next five years.

Asset Retirement Obligations

Accounting standards for asset retirement obligations associated with long-lived assets require that the present value of retirement costs for which we have a legal obligation be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The associated ARO accretion expense for our non-regulated operations is included within Depreciation, depletion and amortization on the accompanying Consolidated Statements of Income. The accounting for the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset or a regulatory liability.

We initially record liabilities for the present value of retirement costs for which we have a legal obligation, with an equivalent amount added to the asset cost. The asset is then depreciated or depleted over the appropriate useful life and the liability is accreted over time by applying an interest method of allocation. Any difference in the actual cost of the settlement of the liability and the recorded amount is recognized as a gain or loss in the results of operations at the time of settlement for our non-regulated operations, other than Oil and Gas. For the Oil and Gas segment, differences in the settlement of the liability and the recorded amount are generally reflected as adjustments to the capitalized cost of oil and gas properties and depleted pursuant to our use of the full cost method. Additional information is included in Note 7.

Fair Value Measurements

Derivative Financial Instruments

Assets and liabilities are classified and disclosed in one of the following fair value categories:

Level 1 — Unadjusted quoted prices available in active markets that are accessible at the measurement date for identical unrestricted assets or liabilities. This level primarily consists of financial instruments such as exchange-traded securities or listed derivatives.

Level 2 — Pricing inputs include quoted prices for identical or similar assets and 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.

Level 3 — Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs reflect management's best estimate of fair value using its own assumptions about the assumptions a market participant would use in pricing the asset or liability.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels. We record transfers, if necessary, between levels at the end of the reporting period for all of our financial instruments.

Transfers into Level 3, if any, occur when significant inputs used to value the derivative instruments become less observable such as a significant decrease in the frequency and volume in which the instrument is traded, negatively impacting the availability of observable pricing inputs. Transfers out of Level 3, if any, occur when the significant inputs become more observable such as the time between the valuation date and the delivery date of a transaction becomes shorter, positively impacting the availability of observable pricing inputs.

Valuation Methodologies for Derivatives

Oil and Gas Segment:

- The commodity contracts for the Oil and Gas segment are valued under the market approach and include exchange-traded futures and basis swaps. Fair value was derived using exchange quoted settlement prices from third party brokers for similar instruments as to quantity and timing. The prices are then validated through third party sources and therefore support Level 2 disclosure.

Utilities Segment:

- The commodity contracts for the Utilities, valued using the market approach, include exchange-traded futures, options and basis swaps (Level 2) and OTC basis swaps (Level 3) for natural gas contracts. For Level 2 assets and liabilities, fair value was derived using broker quotes validated by the Chicago Mercantile Exchange pricing for similar instruments. For Level 3 assets and liabilities, fair value was derived using average price quotes from the OTC contract broker and an independent third party market participant since these instruments are not traded on an exchange.

Corporate Segment:

- The interest rate swaps are valued using the market valuation approach. We establish fair value by obtaining price quotes directly from the counterparty which are based on the floating three-month LIBOR curve for the term of the contract. The fair value obtained from the counterparty is then validated by utilizing a nationally recognized service that obtains observable inputs to compute fair value for the same instrument. In addition, the fair value for the interest rate swap derivatives includes a CVA component. The CVA considers the fair value of the interest rate swap and the probability of default based on the life of the contract. For the probability of a default component, we utilize observable inputs supporting Level 2 disclosure by using our credit default spread, if available, or a generic credit default spread curve that takes into account our credit ratings.

Additional information is included in Note 9.

Derivatives and Hedging Activities

The accounting standards for derivatives and hedging require that derivative instruments be recorded on the balance sheet as either an asset or liability measured at its fair value and that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met and designated accordingly, and if they qualify for certain exemptions, including the normal purchases and normal sales exemption. Each Consolidated Balance Sheet reflects the offsetting of net derivative positions with fair value amounts for cash collateral with the same counterparty when a legal right of offset exists.

Accounting standards for derivatives and hedging require that the unrealized gains or losses on a derivative instrument designated and qualifying as a fair value hedging instrument as well as the offsetting unrealized gain or loss on the hedged item attributable to the hedged risk be recognized currently in earnings in the same accounting period. Conversely, the effective portion of the unrealized gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument must be reported as a component of other comprehensive income and be reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument, if any, is recognized currently in earnings.

Revenues and expenses on contracts that qualify are designated as normal purchases and normal sales and are recognized when the underlying physical transaction is completed under the accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable amount of time, and price is not tied to an unrelated underlying derivative. As part of our regulated electric and gas operations, we enter into contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy in the retail and wholesale markets with the intent and ability to deliver or take delivery. If it was determined that a transaction designated as a normal purchase or normal sale no longer met the exceptions, the fair value of the related contract would be reflected as either an asset or liability, under the accounting standards for derivatives and hedging.

We utilize master netting agreements which consist of an agreement between two parties who have multiple contracts with each other that provide for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim, or the obligation to return, cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty.

Deferred Financing Costs

Deferred financing costs are amortized using the effective interest method over the estimated useful life of the related debt.

Development Costs

According to accounting standards for business combinations, we expense, when incurred, development and acquisition costs associated with corporate development activities prior to acquiring or beginning construction of a project. Expensed development costs are included in Other operating expenses on the accompanying Consolidated Statements of Income.

Legal Costs

Litigation liabilities, including potential settlements, are recorded when it is both probable that a liability or settlement has been incurred and the amount can be reasonably estimated. Legal costs related to ongoing litigation are expensed as incurred.

When a range of the probable loss exists and no amount within the range is a better estimate than any other amount, we record a loss contingency at the minimum amount in the range. If the loss contingency at issue is not both probable and reasonably estimable, we do not establish an accrual and the matter will continue to be monitored for any developments that would make the loss contingency both probable and reasonably estimable.

Regulatory Accounting

Our Utilities Group follows accounting standards for regulated operations and reflects the effects of the numerous rate-making principles followed by the various state and federal agencies regulating the utilities. The accounting policies followed are generally subject to the Uniform System of Accounts of the FERC. These accounting policies differ in some respects from those used by our non-regulated businesses. If rate recovery becomes unlikely or uncertain due to competition or regulatory action, these accounting standards may no longer apply which would require these net assets to be charged to current income or OCI. Our regulatory assets represent amounts for which we will recover the cost, but generally are not allowed a return, except as described below. In the event we determine that our regulated net assets no longer meet the criteria for following accounting standards for regulated operations, the accounting impact to us could be an extraordinary non-cash charge to operations, which could be material.

We had the following regulatory assets and liabilities (in thousands):

	Maximum Amortization (in years)	As of December 31, 2014	As of December 31, 2013
Regulatory assets			
Deferred energy and fuel cost adjustments - current [(a)(d)]	1	$23,820	$16,775
Deferred gas cost adjustments [(a)(d)]	2	37,471	4,799
Gas price derivatives [(a)]	7	18,740	7,567
AFUDC [(b)]	45	12,358	12,315
Employee benefit plans [(c) (e)]	12	97,126	67,059
Environmental [(a)]	subject to approval	1,314	1,800
Asset retirement obligations [(a)]	44	3,287	3,266
Bond issue cost [(a)]	23	3,276	3,419
Renewable energy standard adjustment [(a)]	5	9,622	14,186
Flow through accounting [(c)]	35	25,887	20,916
Decommissioning costs	10	12,484	—
Other regulatory assets [(a)]	15	12,454	10,546
		$257,839	$162,648
Regulatory liabilities			
Deferred energy and gas costs [(a)]	1	$6,496	$11,708
Employee benefit plans [(c) (e)]	12	53,139	34,431
Cost of removal [(a)]	44	78,249	64,970
Other regulatory liabilities [(c)]	25	10,947	9,047
		$148,831	$120,156

(a) Recovery of costs, but we are not allowed a rate of return.

(b) In addition to recovery of costs, we are allowed a rate of return.

(c) In addition to recovery or repayment of costs, we are allowed a return on a portion of this amount or a reduction in rate base, respectively.

(d) Our deferred energy, fuel cost and gas cost adjustments represent the cost of electricity and gas delivered to our electric and gas utility customers that is either higher or lower than current rates and will be recovered or refunded in future rates. Increases in the current year balances as of December 31, 2014 are primarily due to higher natural gas prices driven by demand and market conditions during our peak winter heating season. Our electric and gas utilities file periodic quarterly, semi-annual and/or annual filings to recover these costs based on the respective cost mechanisms approved by their applicable state utility commissions.

(e)

Increases are due to a decrease in the discount rate and a change in the mortality tables used in employee benefit plan estimates.

Regulatory assets represent items we expect to recover from customers through probable future rates.

Deferred Energy and Fuel Cost Adjustments - Deferred energy and fuel cost adjustments represent the cost of electricity delivered to our electric utility customers that is either higher or lower than the current rates and will be recovered or refunded in future rates. Deferred energy and fuel cost adjustments are recorded and recovered or amortized as approved by the appropriate state commission.

Deferred Gas Cost Adjustment - Our regulated gas utilities have GCA provisions that allow them to pass the cost of gas on to their customers. The GCA is based on forecasts of the upcoming gas costs and recovery or refund of prior under-recovered or over-recovered costs. To the extent that gas costs are under-recovered or over-recovered, they are recorded as a regulatory asset or liability, respectively. Our Gas Utilities file periodic estimates of future gas costs based on market forecasts with state utility commissions.

Gas Price Derivatives - Our regulated utilities, as allowed or required by state utility commissions, have entered into certain exchange-traded natural gas futures and options to reduce our customers’ underlying exposure to fluctuations in gas prices. Gas price derivatives represent our unrealized positions on our commodity contracts supporting our utilities. The 7-year term represents the maximum forward term hedged.

AFUDC - The equity component of AFUDC is considered a permanent difference for tax purposes with the tax benefit being flowed through to customers as prescribed or allowed by regulators. If, based on a regulator’s action, it is probable the utility will recover the future increase in taxes payable represented by this flow-through treatment through a rate revenue increase, a regulatory asset is recognized. This regulatory asset is a temporary difference for which a deferred tax liability must be recognized. Accounting standards for income taxes specifically address AFUDC-equity and require a gross-up of such amounts to reflect the revenue requirement associated with a rate-regulated environment.

Employee Benefit Plans - Employee benefit plans include the unrecognized prior service costs and net actuarial loss associated with our defined benefit pension plans and post-retirement benefit plans in regulatory assets rather than in accumulated other comprehensive income, including costs being amortized from the Aquila Transaction.

Environmental - Environmental is associated with manufactured gas plant sites. The amortization of this asset is first offset by recognition of insurance proceeds and settlements with other third parties. Any remaining recovery will be requested in future rate filings. Recovery has not yet been approved by the applicable commission or board and therefore, the recovery period is unknown.

Asset Retirement Obligations - Asset retirement obligations represent the estimated recoverable costs for legal obligations associated with the retirement of a tangible long-lived asset. See Note 7 for additional details.

Bond Issue Costs - Bond issue costs are recovered over the remaining life of the original issue or, if refinanced, over the life of the new issue.

Renewable Energy Standard Adjustment - The renewable energy standard adjustment is associated with incentives for our Colorado Electric customers to install renewable energy equipment at their location. These incentives are recovered over time with an additional rider charged on customers’ bills.

Flow-Through Accounting - Under flow-through accounting, the income tax effects of certain tax items are reflected in our cost of service for the customer in the year in which the tax benefits are realized and result in lower utility rates. This regulatory treatment was applied to the tax benefit generated by repair costs that were previously capitalized for tax purposes in a rate case settlement that was reached with respect to Black Hills Power in 2010. In this instance, the agreed upon rate increase was less than it would have been absent the flow-through treatment. A regulatory asset was established to reflect that future increases in income taxes payable will be recovered from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record a tax benefit for costs considered repairs for tax purposes, but are capitalized for book purposes.

Decommissioning Costs - Black Hills Power and Colorado Electric received approval for regulatory treatment on the remaining net book values of their decommissioned coal plants in 2014. These balances were in Property, Plant and Equipment in 2013.

Regulatory liabilities represent items we expect to refund to customers through probable future decreases in rates.

Deferred Energy and Gas Costs - Deferred energy costs and gas costs related to over-recovery of purchased power, transmission and natural gas costs.

Employee Benefit Plans - Employee benefit plans represent the cumulative excess of pension and retiree healthcare costs recovered in rates over pension expense recorded in accordance with accounting standards for compensation - retirement benefits. In addition, this regulatory liability includes the income tax effect of the adjustment required under accounting for compensation - defined benefit plans, to record the full pension and post-retirement benefit obligations. Such income tax effect has been grossed-up to account for the revenue requirement aspect of a rate regulated environment.

Cost of Removal - Cost of removal represents the estimated cumulative net provisions for future removal costs included in depreciation expense for which there is no legal obligation for removal.

Income Taxes

The Company and its subsidiaries file consolidated federal income tax returns. Each tax paying entity records income taxes as if it were a separate taxpayer and consolidating adjustments are allocated to the subsidiaries based on separate company computations of taxable income or loss.

We use the liability method in accounting for income taxes. Under the liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities as well as operating loss and tax credit carry forwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements. We classify deferred tax assets and liabilities into current and non-current amounts based on the nature of the related assets and liabilities.

It is our policy to apply the flow-through method of accounting for investment tax credits as allowed by our rate-regulated jurisdictions. Under the flow-through method, investment tax credits are reflected in net income as a reduction to income tax expense in the year they qualify. Another acceptable accounting method and an exception to this general policy currently in our regulated businesses is to apply the deferral method whereby the credit is amortized as a reduction of income tax expense over the useful lives of the related property.

We recognize interest income or interest expense and penalties related to income tax matters in Income tax (expense) benefit on the Consolidated Statements of Income.

We account for uncertainty in income taxes recognized in the financial statements in accordance with the accounting standards for income taxes. The unrecognized tax benefit is classified in Other deferred credits and other liabilities on the accompanying Consolidated Balance Sheets. See Note 14 for additional information.

Earnings per Share of Common Stock

Basic earnings per share from continuing and discontinued operations is computed by dividing Income (loss) from continuing or discontinued operations by the weighted average number of common shares outstanding during each year. Diluted earnings per share is computed by including all dilutive common shares outstanding during each year. Diluted common shares are primarily due to outstanding stock options, restricted stock and performance shares under our equity compensation plans.

A reconciliation of share amounts used to compute earnings (loss) per share is as follows (in thousands):

	December 31, 2014	December 31, 2013	December 31, 2012
Income (loss) from continuing operations	$128,781	$115,846	$88,505
Weighted average shares - basic	44,394	44,163	43,820
Dilutive effect of:			
Equity compensation	204	256	250
Other	—	—	3
Weighted average shares - diluted	44,598	44,419	44,073
Income (loss) from continuing operations, per share - Diluted	$2.89	$2.61	$2.01

The following outstanding securities were not included in the computation of diluted earnings per share as their effect would have been anti-dilutive (in thousands):

	December 31, 2014	December 31, 2013	December 31, 2012
Equity compensation	81	22	163
Anti-dilutive shares excluded from computation of earnings (loss) per share	81	22	163

Discontinued Operations

On February 29, 2012, we sold the outstanding stock of our Energy Marketing segment, Enserco Energy Inc. The transaction was completed through a stock purchase agreement and certain other ancillary agreements. In accordance with GAAP, indirect corporate costs previously allocated to a disposal group cannot be reclassified to discontinued operations. See Note 21 for additional information.

Recently Issued and Adopted Accounting Standards

We have implemented all new accounting pronouncements that are in effect and may impact our financial statements and do not believe that there are any other new accounting pronouncements that have been issued that might have a material impact on our financial position, results of operations, or cash flows.

Revenue from Contracts with Customers, ASU 2014-09

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers. The standard provides companies with a single model for use in accounting for revenue arising from contracts with customers and supersedes current revenue recognition guidance, including industry-specific revenue guidance. The core principle of the model is to recognize revenue when control of the goods or services transfers to the customer, as opposed to recognizing revenue when the risks and rewards transfer to the customer under the existing revenue guidance. ASU 2014-09 is effective for annual and interim reporting periods beginning after December 15, 2016 and early adoption is not permitted. We are currently assessing the impact, if any, that ASU 2014-09 will have on our financial position, results of operations or cash flows.

Recently Issued Accounting Pronouncements and Legislation

Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforwards Exists, ASU 2013-11

In July 2013, the FASB issued an amendment to accounting for income taxes which provides guidance on financial statement presentation of an unrecognized tax benefit when an NOL carryforward, a similar tax loss, or a tax credit carryforward exists. The objective in issuing this amendment is to eliminate diversity in practice resulting from a lack of guidance on this topic in current GAAP. Under the amendment, an entity must present an unrecognized tax benefit, or a portion of an unrecognized tax benefit, in the financial statements as a reduction to a deferred tax asset for an NOL carryforward, a similar tax loss, or a tax credit carryforward except under certain conditions. The amendment is effective for fiscal years beginning after December 15, 2013 and interim periods within those years, and should be applied to all unrecognized tax benefits that exist as of the effective date. The adoption of this standard did not have any impact on our financial position, results of operations or cash flows.

Final Tangible Property Regulations, Treasury Decision 9636

In September 2013, the U.S. Treasury issued final regulations addressing the tax consequences associated with amounts paid to acquire, produce, or improve tangible property. The regulations had the effect of a change in law and as a result, the impact should be taken into account in the period of adoption. In general, such regulations apply to tax years beginning on or after January 1, 2014, with early adoption permitted. We implemented all of the provisions of the final regulations with the filing of the 2013 federal income tax return in September 2014. The adoption of the final regulations did not have a material impact on our consolidated financial statements.

(2) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment at December 31 consisted of the following (dollars in thousands):

Utilities Group	2014		2013		Lives (in years)	
Electric Utilities	Property, Plant and Equipment	Weighted Average Useful Life (in years)	Property, Plant and Equipment	Weighted Average Useful Life (in years)	Minimum	Maximum
Electric plant:						
Production	$1,125,845	45	$951,138	45	25	65
Electric transmission	284,032	49	238,542	50	40	65
Electric distribution	718,342	44	666,589	44	15	65
Plant acquisition adjustment (a)	4,870	32	4,870	32	32	32
General	152,982	21	138,263	22	3	60
Capital lease - plant in service (b)	261,441	20	261,441	20	20	20
Total electric plant in service	$2,547,512		$2,260,843			
Construction work in progress	49,700		203,760			
Total electric plant	2,597,212		2,464,603			
Less accumulated depreciation and amortization	484,406		472,970			
Electric plant net of accumulated depreciation and amortization	$2,112,806		$1,991,633			

(a) The plant acquisition adjustment is included in rate base and is being recovered with 16 years remaining.

(b) Capital lease - plant in service represents the assets accounted for as a capital lease under the PPA between Colorado Electric and Black Hills Colorado IPP. The capital lease ends in conjunction with the expiration of the PPA on December 31, 2031.

Gas Utilities	2014 Property, Plant and Equipment	Weighted Average Useful Life (in years)	2013 Property, Plant and Equipment	Weighted Average Useful Life (in years)	Lives (in years) Minimum	Maximum
Gas plant:						
Production	$13	37	$13	37	37	37
Gas transmission	24,090	54	24,984	54	53	57
Gas distribution	557,405	46	507,318	46	41	56
General	90,085	19	85,841	19	16	22
Total gas plant in service	671,593		618,156			
Construction work in progress	16,072		9,417			
Total gas plant	687,665		627,573			
Less accumulated depreciation and amortization	92,035		84,679			
Gas plant net of accumulated depreciation and amortization	$595,630		$542,894			

2014						Lives (in years)		
Non-regulated Energy	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Power Generation	$153,779	$2,262	$156,041	$47,704	$108,337	33	2	40
Coal Mining	145,619	3,748	149,367	90,629	58,738	15	2	59
Oil and Gas	962,395	—	962,395	612,736	349,659	24	3	25
	$1,261,793	$6,010	$1,267,803	$751,069	$516,734			

2013						Lives (in years)		
Non-regulated Energy	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Power Generation	$143,026	$10,491	$153,517	$43,069	$110,448	36	2	40
Coal Mining	149,067	1,156	150,223	86,306	63,917	14	2	59
Oil and Gas	852,384	—	852,384	585,334	267,050	24	3	25
	$1,144,477	$11,647	$1,156,124	$714,709	$441,415			

2014						Lives (in years)		
	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization (a)	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Corporate	$5,524	$5,196	$10,720	$(3,485)	$14,205	11	5	30

(a) Accumulated depreciation, depletion and amortization at Corporate reflects the elimination of the capital lease accumulated depreciation difference between Colorado Electric and Colorado IPP.

2013						Lives (in years)		
	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization (a)	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Corporate	$5,498	$5,647	$11,145	$(3,210)	$14,355	6	2	30

(a) Accumulated depreciation, depletion and amortization at Corporate reflects the elimination of the capital lease accumulated depreciation difference between Colorado Electric and Colorado IPP.

(3) JOINTLY OWNED FACILITIES

Utility Plant

Our consolidated financial statements include our share of several jointly-owned utility facilities as described below. Our share of the facilities expenses are reflected in the appropriate categories of operating expenses in the Consolidated Statements of Income. Each owner of the facility is responsible for financing its investment in the jointly-owned facilities.

- Black Hills Power owns a 20% interest in the Wyodak Plant, a coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp owns the remaining ownership percentage and operates the Wyodak Plant. Black Hills Power receives its proportionate share of the Wyodak Plant’s capacity and is committed to pay its proportionate share of its additions, replacements and operating and maintenance expenses. In addition to supplying Black Hills Power with coal for its share of the Wyodak Plant, our Coal Mining subsidiary, WRDC, supplies PacifiCorp’s share of the coal to the Wyodak Plant under a separate long-term agreement. This coal supply agreement is collateralized by a mortgage on and a security interest in some of WRDC’s coal reserves.

- Black Hills Power also owns a 35% interest in, and is the operator of, the Converter Station Site and South Rapid City Interconnection (the transmission tie), an AC-DC-AC transmission tie. Basin Electric owns the remaining ownership percentage. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides us with access to both the WECC region and the MAPP region. The total transfer capacity of the tie is 400 MW - 200 MW West to East and 200 MW from East to West. Black Hills Power is committed to pay its proportionate share of the additions and replacements to and operating and maintenance expenses of the transmission tie.

- Black Hills Power owns 52% of the Wygen III coal-fired generation facility. MDU and the City of Gillette each owns an undivided ownership interest in Wygen III and are obligated to make payments for costs associated with administrative services and their proportionate share of the costs of operating the plant for the life of the facility. We retain responsibility for plant operations. Our Coal Mining subsidiary supplies coal to Wygen III for the life of the plant.
- Colorado Electric owns 50% of the Busch Ranch Wind Project while AltaGas owns the remaining undivided ownership interest and is obligated to make payments for costs associated with their proportionate share of the costs of operating the wind project for the life of the facility. We retain responsibility for operations of the wind farm.

Non-Regulated Plants

Our consolidated financial statements include our share of a jointly-owned non-regulated power generation facility as described below. Our share of direct expenses for the jointly-owned facility is included in the corresponding categories of operating expenses in the accompanying Consolidated Statements of Income. Each of the respective owners is responsible for providing its own financing.

- Black Hills Wyoming owns 76.5% of the Wygen I plant while MEAN owns the remaining ownership percentage. MEAN is obligated to make payments for its share of the costs associated with administrative services, plant operations and coal supply provided by our Coal Mining subsidiary during the life of the facility. We retain responsibility for plant operations.

At December 31, 2014, our interests in jointly-owned generating facilities and transmission systems were (in thousands):

	Plant in Service	Construction Work in Progress	Accumulated Depreciation
Wyodak Plant	$110,123	$1,201	$53,816
Transmission Tie	$19,648	$—	$4,976
Wygen I	$109,040	$1,765	$31,852
Wygen III	$136,220	$29	$13,811
Busch Ranch Wind Project	$18,590	$—	$1,573

(4) BUSINESS SEGMENTS INFORMATION

Our reportable segments are based on our method of internal reporting, which generally segregates the strategic business groups due to differences in products, services and regulation. Primarily, all of our operations and assets are located within the United States.

On February 29, 2012, we sold our Energy Marketing segment, Enserco, which resulted in this segment being reclassified as discontinued operations. For comparative purposes, all prior periods presented have been restated to reflect the reclassification of this segment as discontinued operations. Indirect corporate costs and inter-segment interest expense related to Enserco that have not been reclassified as discontinued operations have been reclassified to our Corporate segment. For further information see Note 21.

Segment information was as follows (in thousands):

Total Assets (net of inter-company eliminations) as of December 31,	2014	2013
Utilities:		
Electric [(a)]	$2,748,680	$2,525,947
Gas	906,922	805,617
Non-regulated Energy:		
Power Generation [(a)]	76,945	95,692
Coal Mining	74,407	78,825
Oil and Gas	366,247	288,366
Corporate	106,605	80,731
Total assets	$4,279,806	$3,875,178

(a) The PPA under which Black Hills Colorado IPP provides generation to support Colorado Electric customers from the Pueblo Airport Generation station is accounted for as a capital lease. As such, assets owned by our Power

Generation segment are recorded at Colorado Electric under accounting for a capital lease.

Capital Expenditures and Asset Acquisitions[a] for the years ended December 31,	2014	2013
Utilities:		
Electric Utilities	$193,199	$222,262
Gas Utilities	70,528	63,205
Non-regulated Energy:		
Power Generation	2,379	13,533
Coal Mining	6,676	5,528
Oil and Gas	109,439	64,687
Corporate	9,046	10,319
Total capital expenditures and asset acquisitions	$391,267	$379,534

(a) Includes accruals for property, plant and equipment.

Property, Plant and Equipment as of December 31,	2014	2013
Utilities:		
Electric Utilities [a]	$2,597,212	$2,464,603
Gas Utilities	687,665	627,573
Non-regulated Energy:		
Power Generation [a]	156,041	153,517
Coal Mining	149,367	150,223
Oil and Gas	962,395	852,384
Corporate	10,720	11,145
Total property, plant and equipment	$4,563,400	$4,259,445

(a) The PPA under which Black Hills Colorado IPP provides generation to support Colorado Electric customers from the Pueblo Airport Generation station is accounted for as a capital lease. As such, assets owned by our Power Generation segment are recorded at Colorado Electric under accounting for a capital lease.

	Consolidating Income Statement							
Year ended December 31, 2014	Electric Utilities	Gas Utilities	Power Generation	Coal Mining	Oil and Gas	Corporate	Inter-company Eliminations	Total
Revenue	$683,201	$617,768	$6,401	$31,086	$55,114	$—	$—	$1,393,570
Inter-company revenue	14,110	—	81,157	32,272	—	222,460	(349,999)	—
Total revenue	697,311	617,768	87,558	63,358	55,114	222,460	(349,999)	1,393,570
Fuel, purchased power and cost of natural gas sold	314,573	380,852	—	—	—	116	(113,759)	581,782
Operations and maintenance	165,641	132,635	33,126	41,172	42,659	213,415	(225,473)	403,175
Depreciation, depletion and amortization	79,424	26,499	4,540	10,276	27,584	7,690	(7,930)	148,083
Operating income (loss)	137,673	77,782	49,892	11,910	(15,129)	1,239	(2,837)	260,530
Interest expense	(53,402)	(15,725)	(4,351)	(493)	(2,603)	(50,299)	55,913	(70,960)
Interest income	4,615	441	682	59	918	48,969	(53,759)	1,925
Other income (expense), net	1,164	34	(6)	2,275	183	61,605	(62,574)	2,681
	(30,498)	(20,663)	(17,701)	(3,299)	5,998	24	744	(65,395)

Income tax benefit (expense)								
Income (loss) from continuing operations	$59,552	$41,869	$28,516	$10,452	$(10,633)	$61,538	$(62,513)	$128,781

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Year ended December 31, 2013	Consolidating Income Statement Electric Utilities	Gas Utilities	Power Generation	Coal Mining	Oil and Gas	Corporate	Inter-company Eliminations	Total
Revenue	$651,445	$539,689	$4,648	$25,186	$54,884	$—	$—	$1,275,852
Inter-company revenue	13,863	—	78,389	31,442	—	220,620	(344,314)	—
Total revenue	665,308	539,689	83,037	56,628	54,884	220,620	(344,314)	1,275,852
Fuel, purchased power and cost of natural gas sold	294,048	310,463	—	—	—	125	(112,489)	492,147
Operations and maintenance	159,961	126,073	30,186	39,519	40,365	202,809	(211,977)	386,936
Depreciation, depletion and amortization	77,704	26,381	5,091	11,523	21,770	11,624	(12,876)	141,217
Operating income (loss)	133,595	76,772	47,760	5,586	(7,251)	6,062	(6,972)	255,552
Interest expense [(a)]	(61,537)	(25,234)	(21,178)	(641)	(2,253)	(85,195)	84,250	(111,788)
Unrealized gain (loss) on interest rate swaps, net	—	—	—	—	—	30,169	—	30,169
Interest income	5,277	976	785	10	1,639	69,760	(76,724)	1,723
Other income (expense), net	633	(60)	1	2,304	108	41,453	(42,641)	1,798
Income tax benefit (expense)	(25,834)	(19,747)	(11,080)	(932)	3,545	(7,778)	218	(61,608)
Income (loss) from continuing operations	$52,134	$32,707	$16,288	$6,327	$(4,212)	$54,471	$(41,869)	$115,846

(a) Power Generation includes costs associated with interest rate swaps settled and write-off of deferred financing costs upon repayment of Black Hills Wyoming Project Financing and Corporate includes a write-off of deferred financing costs and a make-whole provision from early repayment of long-term debt (see Note 5).

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Year ended December 31, 2012	Consolidating Income Statement Electric Utilities	Gas Utilities	Power Generation	Coal Mining	Oil and Gas	Corporate	Inter-company Eliminations	Total
Revenue	$610,732	$454,081	$4,189	$25,810	$79,072	$—	$—	$1,173,884
Inter-company revenue	16,234	—	75,200	31,968	—	196,453	(319,855)	—
Total revenue	626,966	454,081	79,389	57,778	79,072	196,453	(319,855)	1,173,884
Fuel, purchased power and cost of natural gas sold	273,474	245,349	—	—	—	—	(111,757)	407,066
Operations and maintenance	146,527	117,390	29,991	42,553	43,267	179,059	(188,051)	370,736
Gain on sale of operating assets [(a)]	—	—	—	—	(29,129)	—	—	(29,129)
Depreciation, depletion and amortization	75,244	25,163	4,599	13,060	38,494	10,936	(12,864)	154,632
Impairment of long-lived assets[(b)]	—	—	—	—	26,868	—	—	26,868
Operating income (loss)	131,721	66,179	44,799	2,165	(428)	6,458	(7,183)	243,711
Interest expense[(c)]	(59,194)	(26,746)	(15,452)	(238)	(4,539)	(92,650)	85,209	(113,610)
Unrealized gain (loss) on interest rate swaps, net	—	—	—	—	—	1,882	—	1,882
Interest income	8,153	2,765	695	1,168	604	64,695	(76,123)	1,957
Other income (expense), net	1,182	105	7	2,616	207	48,769	(49,921)	2,965
Income tax benefit (expense)	(30,264)	(14,313)	(8,721)	(85)	1,927	3,187	(131)	(48,400)
Income (loss) from continuing operations	$51,598	$27,990	$21,328	$5,626	$(2,229)	$32,341	$(48,149)	$88,505

(a) Oil and Gas includes gain on sale of the Williston Basin assets (see Note 21).
(b) Oil and Gas includes a ceiling test impairment (see Note 12).
(c) Corporate includes a make-whole provision from early repayment of long-term debt.

(5) LONG-TERM DEBT

Long-term debt outstanding was as follows (dollars in thousands) as of:

	Due Date	Interest Rate at December 31, 2014	December 31, 2014	December 31, 2013
Corporate				
Senior unsecured notes due 2023	November 30, 2023	4.25%	$525,000	$525,000
Unamortized discount on Senior unsecured note due 2023 (a)			(2,164)	—
Senior unsecured notes due 2020	July 15, 2020	5.88%	200,000	200,000
Corporate term loan due 2015 (b)	June 19, 2015	1.31%	275,000	275,000
Total Corporate Debt			997,836	1,000,000
Electric Utilities				
First Mortgage Bonds due 2044	October 20, 2044	4.43%	85,000	—
First Mortgage Bonds due 2044	October 20, 2044	4.53%	75,000	—
First Mortgage Bonds due 2032	August 15, 2032	7.23%	75,000	75,000
First Mortgage Bonds due 2039	November 1, 2039	6.13%	180,000	180,000
Unamortized discount on First Mortgage Bonds due 2039			(102)	(107)
Pollution control revenue bonds due 2024	October 1, 2024	5.35%	—	12,200
First Mortgage Bonds due 2037	November 20, 2037	6.67%	110,000	110,000
Industrial development revenue bonds due 2021, variable rate (c)	September 1, 2021	0.09%	7,000	7,000
Industrial development revenue bonds due 2027, variable rate (c)	March 1, 2027	0.09%	10,000	10,000
Series 94A Debt, variable rate (c)	June 1, 2024	0.75%	2,855	2,855
Total Electric Utilities			544,753	396,948
Total long-term debt			1,542,589	1,396,948
Less current maturities			275,000	—
Long-term debt, net of current maturities			$1,267,589	$1,396,948

(a) Discount on note initially reflected in deferred financing costs at December 31, 2013.
(b) Variable interest rate, based on LIBOR plus a spread.
(c) Variable interest rate.

Scheduled maturities of long-term debt, excluding amortization of premiums or discounts, for future years are (in thousands):

2015	$275,000
2016	$—
2017	$—
2018	$—
2019	$—

Thereafter	$1,269,855

Our debt securities contain certain restrictive financial covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2014.

Substantially all of the tangible utility property of Black Hills Power and Cheyenne Light is subject to the lien of indentures securing their first mortgage bonds. First mortgage bonds of Black Hills Power and Cheyenne Light may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures. The first mortgage bonds issued by Black Hills Power and Cheyenne Light are callable, but are subject to make-whole provisions which would eliminate any economic benefit for us to call the bonds.

Debt Transactions

On October 1, 2014, Black Hills Power and Cheyenne Light sold $160 million of first mortgage bonds in a private placement to provide permanent financing for Cheyenne Prairie. Black Hills Power issued $85 million of 4.43% coupon first mortgage bonds due October 20, 2044 and Cheyenne Light issued $75 million of 4.53% coupon first mortgage bonds due October 20, 2044. Proceeds from Black Hills Power's bond sale also funded the early redemption of its 5.35% $12 million pollution control revenue bonds, originally due October 1, 2024.

On November 19, 2013, we entered into a $525 million, 4.25% senior unsecured note expiring on November 30, 2023. The proceeds from this new debt were used to:

- Redeem our $250 million senior unsecured 9.0% notes originally due on May 15, 2014. This repayment occurred on December 19, 2013, for approximately $261 million which included a make-whole provision of approximately $8.5 million and accrued interest which are included in Interest expense on the accompanying Consolidated Statements of Income;
- Repay our variable interest rate Black Hills Wyoming project financing with a remaining balance of approximately $87 million originally due on December 9, 2016, as well as the interest rate swaps designated to this project financing of $8.5 million which is included in Interest expense on the accompanying Consolidated Statements of Income;
- Settle the $250 million notional de-designated interest rate swaps for approximately $64 million;
- Pay down approximately $55 million of the Revolving Credit Facility; and
- Remainder was used for general corporate purposes.

On June 21, 2013, we entered into a new long-term Corporate Term Loan for $275 million expiring on June 19, 2015. The proceeds from this new term loan were used to repay the $150 million corporate term loan due on June 24, 2013, the $100 million corporate term loan due on September 30, 2013 and approximately $25 million in short-term borrowing under our Revolving Credit Facility. The covenants of the new term loan are substantially the same as the Revolving Credit Facility. At December 31, 2014, the cost of borrowing under this term loan was 1.3125% (LIBOR plus a margin of 1.125%).

Amortization Expense

Our deferred financing costs and associated amortization expense included in Interest expense on the accompanying Consolidated Statements of Income were as follows (in thousands):

	Deferred Financing Costs Remaining in Other Assets, Non-current on Balance Sheets at	Amortization Expense for the years ended December 31,		
	December 31, 2014	2014	2013	2012
Senior unsecured notes due 2023	$3,908	$653	$86	$—
Senior unsecured notes due 2014	$—	$—	$635	$462
Senior unsecured notes due 2020	$926	$167	$167	$167
First mortgage bonds due 2044 (Black Hills Power) (a)	$711	$6	$—	$—

First mortgage bonds due 2044 (Cheyenne Light) [(a)]	$654	$6	$—	$—
First mortgage bonds due 2032	$584	$33	$33	$33
First mortgage bonds due 2039	$1,885	$76	$76	$76
First mortgage bonds due 2037	$705	$31	$31	$31
Black Hills Wyoming project financing due 2016 [(b)]	$—	$—	$3,177	$1,037
Other	$483	$53	$57	$57

(a) Deferred financing costs on Cheyenne Prairie first mortgage bonds executed on October 1, 2014.
(b) This project financing was repaid in 2013 and the deferred financing costs were written off.

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Dividend Restrictions

Our credit facility and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. As of December 31, 2014, we were in compliance with these covenants.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our shareholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. The following restrictions on distributions from our subsidiaries existed at December 31, 2014:

- Our utilities are generally limited to the amount of dividends allowed to be paid to our utility holding company under the Federal Power Act and settlement agreements with state regulatory jurisdictions. As of December 31, 2014, the restricted net assets at our Utilities Group were approximately $315 million.

(6) NOTES PAYABLE

Our Revolving Credit Facility and debt securities contain certain restrictive financial covenants. As of December 31, 2014, we were in compliance with all of these financial covenants.

We had the following short-term debt outstanding at the Consolidated Balance Sheets date (in thousands):

	Balance Outstanding at	
	December 31, 2014	December 31, 2013
Revolving Credit Facility	$75,000	$82,500

Revolving Credit Facility

On May 29, 2014, we amended our $500 million corporate Revolving Credit Facility agreement to extend the term through May 29, 2019. This facility is substantially similar to the former agreement, which includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents, to increase the capacity of the facility to $750 million. Borrowings continue to be available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings and the commitment fee under the Revolving Credit Facility are determined based upon our most favorable Corporate credit rating from S&P and Moody’s for our unsecured debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings and letters of credit were 0.125%, 1.125% and 1.125%, respectively, from May 29, 2014 through December 31, 2014; a reduction of 0.25% for each method of borrowing as compared to the previous arrangement. Borrowings under the facility are primarily Eurodollar based. A commitment fee is charged on the unused amount of the Revolving Credit Facility and was 0.175% based on our credit rating, a reduction of 0.025% compared to the prior arrangement.

As of December 31, 2014 and 2013, we had outstanding letters of credit totaling approximately $35 million and approximately $22 million, respectively.

Deferred financing costs on the facility of $3.8 million are being amortized over the estimated useful life of the Revolving Credit Facility and included in Interest expense on the accompanying Consolidated Statements of Income. Upon entering into the Revolving Credit Facility in 2012, $1.5 million of deferred financing costs relating to the previous credit facility was written off through Interest expense. The deferred financing costs on the new facility are being amortized as follows (in thousands):

	Deferred Financing Costs Remaining on Balance Sheets as of	Amortization Expense for the years ended December 31,		
	December 31, 2014	2014	2013	2012
Revolving Credit Facility	$1,779	$616	$752	$2,187

Debt Covenants

Our Revolving Credit Facility and our new Term Loan require compliance with the following financial covenant at the end of each quarter:

	At December 31, 2014	Covenant Requirement
Recourse leverage ratio	55 %	Less than 65 %

(7) ASSET RETIREMENT OBLIGATIONS

We have identified legal retirement obligations related to plugging and abandonment of natural gas and oil wells in the Oil and Gas segment, reclamation of coal mining sites in the Coal Mining segment and removal of fuel tanks, asbestos, transformers containing polychlorinated biphenyls, an evaporation pond and wind turbines at the regulated Electric Utilities segment and asbestos at our regulated utilities segments. We periodically review and update estimated costs related to these asset retirement obligations. The actual cost may vary from estimates because of regulatory requirements, changes in technology and increased costs of labor, materials and equipment.

The following tables present the details of ARO which are included on the accompanying Consolidated Balance Sheets in Other deferred credits and other liabilities (in thousands):

	December 31, 2013	Liabilities Incurred	Liabilities Settled	Accretion	Revisions to Prior Estimates [(a)] [(b)]	December 31, 2014
Electric Utilities	$6,922	$—	$(85)	$175	$—	$7,012
Gas Utilities	274	—	—	17	—	291
Coal Mining	20,627	345	—	951	(2,785)	19,138
Oil and Gas	24,028	68	(932)	1,043	(3,262)	20,945
Total	$51,851	$413	$(1,017)	$2,186	$(6,047)	$47,386

	December 31, 2012	Liabilities Incurred	Liabilities Settled	Accretion	Revisions to Prior Estimates	December 31, 2013
Electric Utilities	$6,981	$—	$—	$168	$(227)	$6,922
Gas Utilities	259	—	—	15	—	274
Coal Mining	20,286	3	(714)	1,052	—	20,627
Oil and Gas	23,022	143	(1,903)	1,450	1,316	24,028
Total	$50,548	$146	$(2,617)	$2,685	$1,089	$51,851

(a) The Coal Mining Revision to Prior Estimates reflects the change in backfill yards and disturbed acreage used in calculating the estimated liability.

(b) The Oil and Gas Revision to Prior Estimates was due to a change in useful well lives used in calculating the estimated liability.

We also have legally required AROs related to certain assets within our electric and gas utility transmission and distribution systems. These retirement obligations are pursuant to an easement or franchise agreement and are only required if we discontinue our utility service under such easement or franchise agreement. Accordingly, it is not possible to estimate a time period when these obligations could be settled and therefore, a value for the cost of these obligations cannot be measured at this time.

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(8) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operations of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures. Valuation methodologies for our derivatives are detailed within Note 1.

Market Risk

Market risk is the potential loss that may occur as a result of an adverse change in market price or rate. We are exposed to the following market risks, including, but not limited to:

- Commodity price risk associated with our natural long position with crude oil and natural gas reserves and production and fuel procurement for certain of our gas-fired generation assets; and

- Interest rate risk associated with our variable rate debt and our other short-term and long-term debt instruments.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty.

For production and generation activities, we attempt to mitigate our credit exposure by conducting business primarily with high credit quality entities, setting tenor and credit limits commensurate with counterparty financial strength, obtaining master netting agreements and mitigating credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit and other security agreements.

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer’s current creditworthiness, as determined by review of their current credit information. We maintain a provision for estimated credit losses based upon historical experience and any specific customer collection issue that is identified.

As of December 31, 2014, our credit exposure included a $0.6 million exposure to a non-investment grade rural electric cooperative. The remainder of our credit exposure was concentrated primarily among retail utility customers, investment grade companies, cooperative utilities and federal agencies. Our derivative and hedging activities included in the accompanying Consolidated Balance Sheets, Consolidated Statements of Income and Consolidated Statements of Comprehensive Income (Loss) are detailed below and within Note 9.

Oil and Gas Exploration and Production

We produce natural gas, NGLs and crude oil through our exploration and production activities. Our natural long positions, or unhedged open positions, result in commodity price risk and variability to our cash flows.

To mitigate commodity price risk and preserve cash flows, we primarily use exchange traded futures and related options to hedge portions of our crude oil and natural gas production. We elect hedge accounting on these instruments. These transactions were designated at inception as cash flow hedges, documented under accounting standards for derivatives and hedging and initially met prospective effectiveness testing. Effectiveness of our hedging position is evaluated at least quarterly.

The derivatives were marked to fair value and were recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets. The effective portion of the gain or loss on these derivatives for which we have elected cash flow hedge accounting is reported in AOCI in the accompanying Consolidated Balance Sheets and the ineffective portion, if any, is reported in Revenue on the accompanying Consolidated Statements of Income (Loss).

The contract or notional amounts, terms of our commodity derivatives and the derivative balances for our Oil and Gas segment reflected on the Consolidated Balance Sheets were as follows (dollars in thousands) as of:

	December 31, 2014		December 31, 2013	
	Crude oil futures, swaps and options	Natural gas futures, swaps and options	Crude oil futures, swaps and options	Natural gas futures, swaps and options
Notional [(a)]	334,500	6,582,500	412,500	7,082,500
Maximum terms in months [(b)]	1	1	3	1
Derivative assets, current	$—	$—	$55	$—
Derivative assets, non-current	$—	$—	$—	$—
Derivative liabilities, current	$—	$—	$—	$—
Derivative liabilities, non-current	$—	$—	$—	$—

(a) Crude in Bbls, gas in MMBtu.

(b) Refers to the tenor of the derivative instrument. Assets and liabilities are classified as current/non-current based on the production month hedged and the corresponding settlement of the derivative instrument.

Based on December 31, 2014 market prices, a $10 million gain would be reclassified from AOCI during 2015. Estimated and actual realized gains or losses will change during future periods as market prices fluctuate.

Utilities

The operations of our utilities, including power purchase arrangements where our utilities must provide the generation fuel (tolling agreements), expose our utility customers to volatility in natural gas prices; therefore, as allowed or required, by state utility commissions, we have entered into commission-approved hedging programs utilizing natural gas futures, options and basis swaps to reduce our customers' underlying exposure to these fluctuations. These transactions are considered derivatives, and in accordance with accounting standards for derivatives and hedging, mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets, net of balance sheet offsetting as permitted by GAAP. Unrealized and realized gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in the accompanying Consolidated Balance Sheets in accordance with the state utility commission guidelines. Accordingly, the hedging activity is recognized in the Consolidated Statements of Income (Loss) or the Consolidated Statements of Comprehensive Income (Loss) when the related costs are recovered through our rates.

The contract or notional amounts and terms of the natural gas derivative commodity instruments held by our Gas Utilities were as follows, as of:

	December 31, 2014		December 31, 2013	
	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]
Natural gas futures purchased	19,370,000	72	17,930,000	84
Natural gas options purchased	4,020,000	8	3,890,000	8
Natural gas basis swaps purchased	12,005,000	60	14,785,000	60

(a) Term reflects the maximum forward period hedged.

We had the following derivative balances related to the hedges in our Utilities reflected in our Consolidated Balance Sheets as of (in thousands):

	December 31, 2014	December 31, 2013
Derivative assets, current	$—	$662
Derivative assets, non-current	$—	$—
Derivative liabilities, current	$—	$—
Derivative liabilities, non-current	$—	$—
Net unrealized (gain) loss included in Regulatory assets or Regulatory liabilities	$18,740	$7,567

Financing Activities

We entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations. The contract or notional amounts, terms of our interest rate swaps and the interest rate swaps balances reflected on the Consolidated Balance Sheets were as follows (dollars in thousands) as of:

	December 31, 2014 Interest Rate Swaps [(a)]	December 31, 2013 Interest Rate Swaps [(a)]
Notional	$75,000	$75,000
Weighted average fixed interest rate	4.97 %	4.97 %
Maximum terms in years	2.0	3.0
Derivative liabilities, current	$3,340	$3,474
Derivative liabilities, non-current	$2,680	$5,614

(a) These swaps are designated to borrowings on our Revolving Credit Facility. These swaps are priced using three-month LIBOR, matching the floating portion of the related borrowings.

Based on December 31, 2014 market interest rates and balances related to our designated interest rate swaps, a loss of approximately $3.3 million would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. Estimated and realized gains or losses will change during future periods as market interest rates change.

Cash Flow Hedges

The impact of cash flow hedges on our Consolidated Statements of Income (Loss) for years ended were as follows (in thousands):

	December 31, 2014				
Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/ (Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	$(536)	Interest expense	$3,669		$—
Commodity derivatives	14,681	Revenue	1,995		—
Total	$14,145		$5,664		$—

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Derivatives in Cash Flow Hedging Relationships	December 31, 2013 Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	$7,935	Interest expense	$6,989		$—
Commodity derivatives	(956)	Revenue	(927)		—
Total	$6,979		$6,062		$—

Derivatives in Cash Flow Hedging Relationships	December 31, 2012 Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	$(4,794)	Interest expense	$(7,607)		$—
Commodity derivatives	2,639	Revenue	8,784		—
Total	$(2,155)		$1,177		$—

Derivatives Not Designated as Hedge Instruments

The impacts of derivative instruments not designated as hedge instruments on our Consolidated Statements of Income (Loss) for the years ended December 31 were as follows (in thousands):

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	2014 Amount of Gain/(Loss) on Derivatives Recognized in Income	2013 Amount of Gain/(Loss) on Derivatives Recognized in Income	2012 Amount of Gain/(Loss) on Derivatives Recognized in Income
Interest rate swaps - unrealized (a)	Unrealized gain (loss) on interest rate swap, net	$—	$30,169	$1,882
Interest rate swaps - realized (a)	Interest expense	—	(12,902)	(12,959)
		$—	$17,267	$(11,077)

(a) These interest rate swaps were settled in the fourth quarter of 2013.

(9) FAIR VALUE MEASUREMENTS

Recurring Fair Value Measurements

There have been no significant transfers between Level 1 and Level 2 derivative balances during 2014 or 2013. Amounts included in cash collateral and counterparty netting in the following tables represent the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions, netting of asset and liability positions permitted in accordance with accounting standards for offsetting as well as cash collateral posted with the same counterparties.

A discussion of fair value of financial instruments is included in Note 10. The following tables set forth, by level within the fair value hierarchy, our gross assets and gross liabilities and related offsetting as permitted by GAAP that were accounted for at fair value on a recurring basis for derivative instruments (in thousands):

	As of December 31, 2014				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
Assets:					
Commodity derivatives - Oil and Gas:					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	8,599	—	(8,599)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	6,558	—	(6,558)	—
Commodity derivatives - Utilities	—	2,389	—	(2,389)	—
Total	$—	$17,546	$—	$(17,546)	$—
Liabilities:					
Commodity derivatives - Oil and Gas:					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	—	—	—	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	473	—	(473)	—
Commodity derivatives - Utilities	—	19,303	—	(19,303)	—
Interest rate swaps	—	6,020	—	—	6,020
Total	$—	$25,796	$—	$(19,776)	$6,020

	As of December 31, 2013				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
Assets:					
Commodity derivatives - Oil and Gas:					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	130	—	(75)	55
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	815	—	(815)	—
Commodity derivatives - Utilities	—	3,030	—	(2,368)	662
Total	$—	$3,975	$—	$(3,258)	$717
Liabilities:					
Commodity derivatives - Oil and Gas:					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	1,229	—	(1,229)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	531	—	(531)	—
Commodity derivatives - Utilities	—	9,100	—	(9,100)	—
Interest rate swaps	—	9,088	—	—	9,088
Total	$—	$19,948	$—	$(10,860)	$9,088

Fair Value Measures by Balance Sheet Classification

As required by accounting standards for derivatives and hedges, fair values within the following tables are presented on a gross basis, aside from the netting of asset and liability positions permitted in accordance with accounting standards for offsetting and under terms of our master netting agreements and the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions. However, the amounts do not include net cash collateral on deposit in margin accounts at December 31, 2014 and 2013, to collateralize certain financial instruments, which are included in Derivative assets and/or Derivative liabilities. Therefore, the balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not agree with the amounts presented on our Consolidated Balance Sheets, nor will they correspond to the fair value measurements presented in Note 8.

The following tables present the fair value and balance sheet classification of our derivative instruments as of December 31, (in thousands):

		2014		2013	
	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:					
Commodity derivatives	Derivative assets - current	$10,391	$—	$248	$—
Commodity derivatives	Derivative assets - non-current	4,766	—	698	—
Commodity derivatives	Derivative liabilities - current	—	185	—	1,541
Commodity derivatives	Derivative liabilities - non-current	—	288	—	219
Interest rate swaps	Derivative liabilities - current	—	3,340	—	3,474
Interest rate swaps	Derivative liabilities - non-current	—	2,680	—	5,614
Total derivatives designated as hedges		$15,157	$6,493	$946	$10,848
Derivatives not designated as hedges:					
Commodity derivatives	Derivative assets - current	$—	$—	$662	$—
Commodity derivatives	Derivative assets - non-current	—	—	—	—
Commodity derivatives	Derivative liabilities - current	—	8,032	—	—
Commodity derivatives	Derivative liabilities - non-current	—	8,882	—	6,732
Interest rate swaps	Derivative liabilities - current	—	—	—	—
Interest rate swaps	Derivative liabilities - non-current	—	—	—	—
Total derivatives not designated as hedges		$—	$16,914	$662	$6,732

Derivatives Offsetting

It is our policy to offset in our Consolidated Balance Sheets contracts which provide for legally enforceable netting for our accounts receivable and payable and derivative activities.

As required by accounting standards for derivatives and hedges, fair values within the following tables reconcile the gross amounts to the net amounts. Amounts included in Gross Amounts Offset on Consolidated Balance Sheets in the following tables include the netting of asset and liability positions permitted in accordance with accounting standards for offsetting as well as the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions as well as cash collateral posted with the same counterparties. Additionally, the amounts reflect cash collateral on deposit in margin accounts at December 31, 2014 and December 31, 2013, to collateralize certain financial instruments, which are included in Derivative assets and/or Derivative liabilities. Therefore, the gross amounts are not indicative of either our actual credit exposure or net economic exposure.

Offsetting of derivative assets and derivative liabilities on our Consolidated Balance Sheets at December 31, 2014 was as follows (in thousands):

Derivative Assets	Gross Amounts of Derivative Assets	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Assets on Consolidated Balance Sheets
Subject to master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	$8,599	$(8,599)	$—
Oil and Gas - Crude Options	—	—	—
Oil and Gas - Natural Gas Basis Swaps	6,558	(6,558)	—
Utilities	2,389	(2,389)	—
Total derivative assets subject to a master netting agreement or similar arrangement	17,546	(17,546)	—
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	—	—	—
Oil and Gas - Crude Options	—	—	—
Oil and Gas - Natural Gas Basis Swaps	—	—	—
Utilities	—	—	—
Total derivative assets not subject to a master netting agreement or similar arrangement	—	—	—
Total derivative assets	$17,546	$(17,546)	$—

Derivative Liabilities	Gross Amounts of Derivative Liabilities	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Liabilities on Consolidated Balance Sheets
Subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	$—	$—	$—
Oil and Gas - Crude Options	—	—	—
Oil and Gas - Natural Gas Basis Swaps	473	(473)	—
Utilities	19,303	(19,303)	—
Interest Rate Swaps	—	—	—
Total derivative liabilities subject to a master netting agreement or similar arrangement	19,776	(19,776)	—
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	—	—	—
Oil and Gas - Crude Options	—	—	—
Oil and Gas - Natural Gas Basis Swaps	—	—	—
Utilities	—	—	—
Interest Rate Swaps	6,020	—	6,020
Total derivative liabilities not subject to a master netting agreement or similar arrangement	6,020	—	6,020
Total derivative liabilities	$25,796	$(19,776)	$6,020

Offsetting of derivative assets and derivative liabilities on our Consolidated Balance Sheets as of December 31, 2013 were as follows (in thousands):

Derivative Assets	Gross Amounts of Derivative Assets	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Assets on Consolidated Balance Sheets
Subject to master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	$75	$(75)	$—
Oil and Gas - Crude Options	—	—	—
Oil and Gas - Natural Gas Basis Swaps	815	(815)	—
Utilities	3,030	(2,368)	662
Total derivative assets subject to a master netting agreement or similar arrangement	3,920	(3,258)	662
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	55	—	55
Oil and Gas - Crude Options	—	—	—
Oil and Gas - Natural Gas Basis Swaps	—	—	—
Utilities	—	—	—
Total derivative assets not subject to a master netting agreement or similar arrangement	55	—	55

Total derivative assets	$3,975	$(3,258)	$717

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Derivative Liabilities	Gross Amounts of Derivative Liabilities	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Liabilities on Consolidated Balance Sheets
Subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	$1,229	$(1,229)	$—
Oil and Gas - Crude Options	—	—	—
Oil and Gas - Natural Gas Basis Swaps	531	(531)	—
Utilities	9,100	(9,100)	—
Interest Rate Swaps	—	—	—
Total derivative liabilities subject to a master netting agreement or similar arrangement	10,860	(10,860)	—
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	—	—	—
Oil and Gas - Crude Options	—	—	—
Oil and Gas - Natural Gas Basis Swaps	—	—	—
Utilities	—	—	—
Interest Rate Swaps	9,088	—	9,088
Total derivative liabilities not subject to a master netting agreement or similar arrangement	9,088	—	9,088
Total derivative liabilities	$19,948	$(10,860)	$9,088

Derivative assets and derivative liabilities and collateral held by counterparty included in our Consolidated Balance Sheets as of December 31, 2014 were (in thousands):

Contract Type		Net Amount of Total Derivative Assets	Gross Amounts Not Offset on Consolidated Balance Sheets Cash Collateral Received	Net Amount with Counterparty
Assets:				
Oil and Gas	Counterparty A	$—	$—	$—
Oil and Gas	Counterparty B	—	—	—
Utilities	Counterparty A	—	—	—
		$—	$—	$—

Contract Type		Net Amount of Total Derivative Liabilities	Gross Amounts Not Offset on Consolidated Balance Sheets Cash Collateral Paid	Net Amount with Counterparty
Liabilities:				
Oil and Gas	Counterparty A	$—	$(4,392)	$(4,392)
Oil and Gas	Counterparty B	—	—	—
Utilities	Counterparty A	—	(3,093)	(3,093)
Interest Rate Swaps	Counterparty F	6,020	—	6,020

$6,020	$(7,485)	$(1,465)

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Derivative assets and derivative liabilities and collateral held by counterparty included in our Consolidated Balance Sheets as of December 31, 2013 were (in thousands):

			Gross Amounts Not Offset on Consolidated Balance Sheets	
Contract Type		Net Amount of Total Derivative Assets	Cash Collateral Received	Net Amount with Counterparty
Assets:				
Oil and Gas	Counterparty A	$—	$—	$—
Oil and Gas	Counterparty B	55	—	55
Utilities	Counterparty A	662	—	662
		$717	$—	$717

			Gross Amounts Not Offset on Consolidated Balance Sheets	
Contract Type		Net Amount of Total Derivative Liabilities	Cash Collateral Paid	Net Amount with Counterparty
Liabilities:				
Oil and Gas	Counterparty A	$—	$(1,631)	$(1,631)
Oil and Gas	Counterparty B	—	—	—
Utilities	Counterparty A	—	(3,390)	(3,390)
Interest Rate Swap	Counterparty F	9,088	—	9,088
		$9,088	$(5,021)	$4,067

(10) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 9, were as follows at December 31 (in thousands):

	2014		2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [(a)]	$21,218	$21,218	$7,841	$7,841
Restricted cash and equivalents [(a)]	$2,056	$2,056	$2	$2
Notes payable [(a)]	$75,000	$75,000	$82,500	$82,500
Long-term debt, including current maturities [(b)]	$1,542,589	$1,734,555	$1,396,948	$1,491,422

(a) Carrying value approximates fair value due to either short-term length of maturity or variable interest rates that approximate prevailing market rates and therefore is classified in Level 1 in the fair value hierarchy.

(b) Long-term debt is valued based on observable inputs available either directly or indirectly for similar liabilities in active markets and therefore is classified in Level 2 in the fair value hierarchy.

Cash and Cash Equivalents

Included in cash and cash equivalents is cash, overnight repurchase agreement accounts, money market funds, and term deposits. As part of our cash management process, excess operating cash is invested in overnight repurchase agreements with our bank. Repurchase agreements are not deposits and are not insured by the U.S. Government, the FDIC, or any other government agency and involve investment risk including possible loss of principal. We believe however, that the market risk arising from holding these financial instruments is minimal.

Restricted Cash and Equivalents

Restricted cash and cash equivalents represent restricted cash and uninsured term deposits.

Notes Payable and Long-Term Debt

For additional information on our notes payable and long-term debt, see Note 5 and Note 6.

(11) STOCK

Equity Compensation Plans

Our 2005 Omnibus Incentive Plan allows for the granting of stock, restricted stock, restricted stock units, stock options and performance shares. We had 522,831 shares available to grant at December 31, 2014.

Compensation expense is determined using the grant date fair value estimated in accordance with the provisions of accounting standards for stock compensation and is recognized over the vesting periods of the individual awards. As of December 31, 2014, total unrecognized compensation expense related to non-vested stock awards was approximately $9.4 million and is expected to be recognized over a weighted-average period of 1.6 years. Stock-based compensation expense included in Operations and maintenance on the accompanying Consolidated Statements of Income was as follows for the years ended December 31 (in thousands):

	2014	2013	2012
Stock-based compensation expense	$9,329	$12,595	$8,271

Stock Options

We have granted options with an option exercise price equal to the fair market value of the stock on the day of the grant. The options granted vest proportionately over 3 years and expire 10 years after the grant date.

A summary of the status of the stock options at December 31, 2014 was as follows:

	Shares (in thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Balance at beginning of period	61	$ 33.25		
Granted [(a)]	81	54.29		
Forfeited/canceled	—	—		
Expired	—	—		
Exercised	(8)	30.87		
Balance at end of period	134	$ 46.12	8.2	$1,027
Exercisable at end of period	46	$ 32.63	6.5	$944

(a) The grant date fair value of the 2014 awards was $12.58 based on a Black-Scholes option pricing model. Assumptions used to estimate the fair value were a 2.1% risk free interest rate, 29.4% expected price volatility, 2.9% expected dividend yield and a 7 year expected life.

The table below provides details of our option plans at December 31 (in thousands):

	2014	2013	2012
Summary of Stock Options			
Unrecognized compensation expense	$816	$130	$218
Intrinsic value of options exercised [(a)]	$199	$789	$623
Net cash received from exercise of options	$237	$2,046	$2,839
Tax benefit realized from exercise of shares [(b)]	$70	$276	$218

(a) The intrinsic value represents the amount by which the market price of the stock on the date of exercise exceeded the exercise price of the option.
(b) The tax benefit realized from the exercise of shares granted was recorded as an increase in equity.

As of December 31, 2014, the unrecognized compensation expense related to non-vested stock options is expected to be recognized over a weighted-average period of 2.1 years.

Restricted Stock

The fair value of restricted stock awards equals the market price of our stock on the date of grant.

The shares carry a restriction on the ability to sell the shares until the shares vest. The shares substantially vest over 3 years, contingent on continued employment. Compensation expense related to the awards is recognized over the vesting period.

A summary of the status of the restricted stock at December 31, 2014, was as follows:

	Restricted Stock	Weighted-Average Grant Date Fair Value
	(in thousands)	
Restricted Stock at beginning of period	262	$36.76
Granted	99	54.34
Vested	(114)	35.25
Forfeited	(14)	43.17
Restricted Stock at end of period	233	$44.60

The weighted-average grant-date fair value of restricted stock granted and the total fair value of shares vested during the years ended December 31, was as follows:

	Weighted-Average Grant Date Fair Value	Total Fair Value of Shares Vested (in thousands)
2014	$54.34	$6,114
2013	$40.56	$5,842
2012	$34.99	$3,781

As of December 31, 2014, there was $6.1 million of unrecognized compensation expense related to non-vested restricted stock that is expected to be recognized over a weighted-average period of 1.7 years.

Performance Share Plan

Certain officers of the Company and its subsidiaries are participants in a performance share award plan, a market-based plan. Performance shares are awarded based on our total shareholder return over designated performance periods as measured against a selected peer group. In addition, certain stock price performance must be achieved for a payout to occur. The final value of the performance shares will vary according to the number of shares of common stock that are ultimately granted based upon the actual level of attainment of the performance criteria.

The performance awards are paid 50% in cash and 50% in common stock. The cash portion accrued is classified as a liability and the stock portion is classified as equity. In the event of a change-in-control, performance awards are paid 100% in cash. If it is determined that a change-in-control is probable, the equity portion of $2.1 million at December 31, 2014 would be reclassified as a liability.

Outstanding performance periods at December 31 were as follows (shares in thousands):

			Possible Payout Range of Target	
Grant Date	Performance Period	Target Grant of Shares	Minimum	Maximum
January 1, 2012	January 1, 2012 - December 31, 2014	64	0%	200%
January 1, 2013	January 1, 2013 - December 31, 2015	61	0%	200%
January 1, 2014	January 1, 2014 - December 31, 2016	44	0%	200%

A summary of the status of the Performance Share Plan at December 31 was as follows:

	Equity Portion		Liability Portion	
	Shares (in thousands)	Weighted-Average Grant Date Fair Value [(a)]	Shares (in thousands)	Weighted-Average Fair Value at [(b)] December 31, 2014
Performance Shares balance at beginning of period	93	$31.34	93	
Granted	23	55.18	23	
Forfeited	(1)	40.12	(1)	
Vested	(31)	25.92	(31)	
Performance Shares balance at end of period	84	$39.58	84	$82.42

(a) The grant date fair values for the performance shares granted in 2014, 2013 and 2012 were determined by Monte Carlo simulation using a blended volatility of 23%, 20% and 21%, respectively, comprised of 50% historical volatility and 50% implied volatility and the average risk-free interest rate of the three-year United States Treasury security rate in effect as of the grant date.

(b) The weighted-average fair value for the liability portion at December 31, 2014 was determined by the actual performance for the 2012 to 2014 performance period at the top of the peer group resulting in a 200% of target payout, and determined by Monte Carlo simulations for the 2013 to 2015 performance period and 2014 to 2016 performance period projecting a 157% and 51% of target payouts, respectively.

The weighted-average grant-date fair value of performance share awards granted in the years ended was as follows:

	Weighted Average Grant Date Fair Value
December 31, 2014	$55.18
December 31, 2013	$35.85
December 31, 2012	$32.26

Performance plan payouts have been as follows (dollars and shares in thousands):

Performance Period	Year of Payment	Shares Issued	Cash Paid	Total Intrinsic Value
January 1, 2011 to December 31, 2013	2014	59	$3,011	$6,020
January 1, 2010 to December 31, 2012	2013	63	$2,267	$4,533
January 1, 2009 to December 31, 2011	2012	—	$—	$—

On January 27, 2015, the Compensation Committee of our Board of Directors determined that the Company's total shareholder return for the January 1, 2012 through December 31, 2014 performance period was at the 100th percentile of its peer group and confirmed a payout equal to 200% of target shares, valued at $7.3 million. The payout was fully accrued at December 31, 2014.

As of December 31, 2014, there was $2.5 million of unrecognized compensation expense related to outstanding performance share plans that is expected to be recognized over a weighted-average period of 1.5 years.

Shareholder Dividend Reinvestment and Stock Purchase Plan

We have a DRSPP under which shareholders may purchase additional shares of common stock through dividend reinvestment and/or optional cash payments at 100% of the recent average market price. We have the option of issuing new shares or purchasing the shares on the open market. We are currently issuing new shares.

A summary of the DRSPP for the years ended December 31 is as follows (shares in thousands):

	2014	2013
Shares Issued	52	67
Weighted Average Price	$54.99	$46.78
Unissued Shares Available	474	286

Preferred Stock

Our articles of incorporation authorize the issuance of 25 million shares of preferred stock of which we had no shares of preferred stock outstanding.

(12) IMPAIRMENT OF LONG-LIVED ASSETS

Under the full cost method of accounting used by our Oil and Gas segment to account for exploration, development and acquisition of crude oil and natural gas reserves, all costs attributable to these activities are capitalized. These capitalized costs, less accumulated amortization and related deferred income taxes, are subject to a ceiling test that limits the pooled costs to the aggregate of the discounted value of future net revenue attributable to proved natural gas and crude oil reserves using a discount rate defined by the SEC plus the lower of cost or market value of unevaluated properties. Any costs in excess of the ceiling are written off as a non-cash charge.

As a result of continued low commodity prices in the second quarter of 2012, we recorded a $27 million non-cash impairment of oil and gas assets included in the Oil and Gas segment. In determining the ceiling value of our assets, we utilized the average of the quoted prices from the first day of each month from the previous 12 months. When this non-cash impairment occurred, commodity prices during the second quarter of 2012 were; for natural gas, the average NYMEX price was $3.15 per Mcf, adjusted to $2.66 per Mcf at the wellhead; for crude oil, the average NYMEX price was $95.67 per barrel, adjusted to $85.36 per barrel at the wellhead.

(13) OPERATING LEASES

We have entered into lease agreements for vehicles, equipment and office facilities. Rental expense incurred under these operating leases, including month to month leases, for the years ended December 31 was as follows (in thousands):

	2014	2013	2012
Rent expense	$6,932	$7,169	$6,839

The following is a schedule of future minimum payments required under the operating lease agreements (in thousands):

2015	$9,962
2016	$2,045
2017	$1,852
2018	$1,829
2019	$1,632
Thereafter	$3,735

(14) INCOME TAXES

Income tax expense (benefit) from continuing operations for the years ended December 31 was (in thousands):

	2014	2013	2012
Current:			
Federal	$(2,319)	$(2,003)	$4,972
State	(1,288)	(173)	3,712
	(3,607)	(2,176)	8,684
Deferred:			
Federal	63,645	56,963	39,876
State	5,563	7,033	68
Tax credit amortization	(206)	(212)	(228)
	69,002	63,784	39,716
	$65,395	$61,608	$48,400

The temporary differences, which gave rise to the net deferred tax liability, for the years ended December 31 were as follows (in thousands):

	2014	2013
Deferred tax assets:		
Regulatory liabilities	$49,243	$33,172
Employee benefits	26,714	28,724
Federal net operating loss	213,466	166,095
Asset impairment	55,067	55,124
Other deferred tax assets[(a)]	76,005	59,078
Less: Valuation allowance	(5,017)	(1,806)
Total deferred tax assets	415,478	340,387
Deferred tax liabilities:		
Accelerated depreciation, amortization and other plant-related differences	(679,911)	(598,415)
Regulatory assets	(25,340)	(24,581)
Mining development and oil exploration	(97,198)	(69,799)
State deferred tax liability	(37,489)	(30,293)
Deferred costs	(35,284)	(15,593)
Other deferred tax liabilities	(15,684)	(15,104)
Total deferred tax liabilities	(890,906)	(753,785)
Net deferred tax liability	$(475,428)	$(413,398)

(a) Other deferred tax assets consist primarily of state tax credits, state net operating loss, alternative minimum tax credit and federal research and development credits. No single item exceeds 5% of the total net deferred tax liability.

The effective tax rate differs from the federal statutory rate for the years ended December 31, as follows:

	2014		2013		2012	
Federal statutory rate	35.0	%	35.0	%	35.0	%
State income tax (net of federal tax effect)	1.1		2.4		2.0	
Amortization of excess deferred income taxes and investment tax credits	(0.1	)	(0.1	)	(0.2	)
Percentage depletion in excess of cost	(1.0	)	(1.0	)	(1.3	)
Equity AFUDC	(0.1	)	—		—	
Tax credits	(0.1	)	(0.5	)	—	
Accounting for uncertain tax positions adjustment	(0.1	)	0.7		0.8	
Flow-through adjustments [(a)]	(0.9	)	(0.9	)	(1.3	)
Other tax differences	(0.1	)	(0.9	)	0.4	
	33.7	%	34.7	%	35.4	%

(a) The flow-through adjustments relate primarily to an accounting method change for tax purposes that allows us to take a current tax deduction for repair costs that continue to be capitalized for book purposes. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and flowed the tax benefit through to our customers in the form of lower rates as a result of a rate case settlement that occurred in 2010. A regulatory asset was established to reflect the recovery of future increases in taxes payable from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record a tax benefit consistent with the flow-through method.

At December 31, 2014, we have federal and gross state NOL carryforwards that will expire at various dates as follows (in thousands):

	Amounts	Expiration Dates		
Federal Net Operating Loss Carryforward	$618,195	2019	to	2034
State Net Operating Loss Carryforward	$513,418	2015	to	2034

As of December 31, 2014, we had a $1.0 million valuation allowance against the state NOL carryforwards. Our 2014 analysis of the ability to utilize such NOLs resulted in an increase of the valuation allowance of approximately $0.5 million, which resulted in an increase to tax expense. The valuation allowance adjustment was primarily attributable to a decrease in taxable income for 2014 due to the enactment of TIPA. Such a decrease impacted the utilization of NOL carryforward in those states where the carryforward period is significantly shorter than the federal carryforward period of 20 years. In certain states, the carryforward period is limited to 5 years. Ultimate usage of these NOLs depends upon our future tax filings. If the valuation allowance is adjusted due to higher or lower than anticipated utilization of the NOLs, the offsetting amount will affect tax expense.

The following table reconciles the total amounts of unrecognized tax benefits, without interest, at the beginning and end of the period included in Other deferred credits and other liabilities on the accompanying Consolidated Balance Sheets (in thousands):

	Changes in Uncertain Tax Positions
Beginning balance at January 1, 2012	$49,327
Additions for prior year tax positions	111
Reductions for prior year tax positions	(8,906)
Additions for current year tax positions	151
Settlements	—
Ending balance at December 31, 2012	40,683
Additions for prior year tax positions	1,526
Reductions for prior year tax positions	(4,578)
Additions for current year tax positions	—
Settlements	—
Ending balance at December 31, 2013	37,631
Additions for prior year tax positions	1,253
Reductions for prior year tax positions	(6,692)
Additions for current year tax positions	—
Settlements	—
Ending balance at December 31, 2014	$32,192

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $1.8 million.

We recognized interest expense of $1.6 million, $1.6 million and $1.4 million for the years ended December 31, 2014, 2013 and 2012, respectively.

We had approximately $11.5 million and $9.9 million of accrued interest (before tax effect) associated with income taxes at December 31, 2014 and 2013, respectively.

We file income tax returns with the IRS and various state jurisdictions. We received a 30-day Letter along with a Revenue Agent's Report from the IRS in regards to the audit of the 2007 to 2009 tax years. A protest was timely filed with IRS in August 2014 related to the like-kind exchange transaction described below and research and development credits and deductions claimed with respect to certain costs and projects. We are also currently under examination by the IRS for the 2010 to 2012 tax years.

We have deferred a substantial amount of tax payments through various tax planning strategies including the deferral of approximately $125 million in income taxes attributable to the like-kind exchange effectuated in connection with the IPP Transaction and Aquila Transaction that occurred in 2008. The IRS has challenged our position with respect to the like-kind exchange and it is reasonably possible that the total unrecognized tax benefits attributable to such transaction could change significantly due to a settlement with the IRS that is anticipated to occur on or before December 31, 2015. However, based on the information currently available, it is difficult to determine any reasonable estimate of the financial statement impact including the impact on the effective tax rate.

Excess foreign tax credits have been generated and are available to offset United States federal income taxes. At December 31, 2014, we had foreign tax credit carryforwards of approximately $0.5 million, which expire between 2015 and 2017.

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As of December 31, 2014, we had a $0.5 million valuation allowance against the foreign tax credit carryforwards. In addition, the carryforward balance reflects the expected utilization of approximately $1.8 million of foreign tax credits to be included as computational adjustments upon finalization of our current IRS examination covering tax years 2007 to 2009. Such foreign tax credits have been reflected as an offset to liabilities for unrecognized tax benefits in recognition of the estimated impact the resolution of material uncertain tax positions could have with respect to utilization.

State tax credits have been generated and are available to offset future state income taxes. At December 31, 2014, we had the following state tax credit carryforwards (in thousands):

State Tax Credit Carryforwards		Expiration Year		
Investment tax credit	$14,793	2023	to	2025
Research and development	$155	No expiration		

As of December 31, 2014, we had a $3.5 million valuation allowance against the state tax credit carryforwards. The re-evaluation of our ability to utilize such credits resulted in an increase of the valuation allowance of approximately $2.7 million of which approximately $1.5 million resulted in an increase to tax expense. The remaining $1.2 million increase is attributable to our regulated business and is being accounted for under the deferral method whereby the credits are amortized to tax expense over the estimated useful life of the underlying asset that generated the credit. The valuation allowance adjustment was primarily attributable to the projected impact of lower commodity prices related to oil and natural gas on forecasted taxable income. Ultimate usage of these credits depends upon our future tax filings. If the valuation allowance is adjusted due to higher or lower than anticipated utilization of the state tax credit carryforwards, the offsetting amount will affect tax expense.

(15) OTHER COMPREHENSIVE INCOME

The components of the reclassification adjustments for the period, net of tax, included in Other comprehensive income were as follows (in thousands):

	Location on the Consolidated Statements of Income	Amount Reclassified from AOCI December 31, 2014	December 31, 2013
Gains and losses on cash flow hedges:			
Interest rate swaps	Interest expense	$3,669	$6,989
Commodity contracts	Revenue	1,995	(927)
		5,664	6,062
Income tax	Income tax benefit (expense)	(2,344)	(2,016)
Total reclassification adjustments related to cash flow hedges, net of tax		$3,320	$4,046
Amortization of defined benefit plans:			
Prior service cost	Utilities - Operations and maintenance	$(102)	$(125)
	Non-regulated energy operations and maintenance	(115)	(128)
Actuarial gain (loss)	Utilities - Operations and maintenance	630	1,693
	Non-regulated energy operations and maintenance	364	1,098
		777	2,538

Income tax	Income tax benefit (expense)	(272)	(883)
Total reclassification adjustments related to defined benefit plans, net of tax		$505	$1,655

Balances by classification included within Accumulated other comprehensive income (loss) on the accompanying Consolidated Balance Sheets were as follows (in thousands):

	Derivatives Designated as Cash Flow Hedges			
	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
As of December 31, 2013	$(6,625)	$(508)	$(10,289)	$(17,422)
Other comprehensive income (loss)	1,695	10,531	(9,848)	2,378
As of December 31, 2014	$(4,930)	$10,023	$(20,137)	$(15,044)

	Derivatives Designated as Cash Flow Hedges			
	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
As of December 31, 2012	$(16,313)	$600	$(19,775)	$(35,488)
Other comprehensive income (loss)	9,688	(1,108)	9,486	18,066
As of December 31, 2013	$(6,625)	$(508)	$(10,289)	$(17,422)

(16) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Years ended December 31,	2014	2013	2012
	(in thousands)		
Non-cash investing activities and financing from continuing operations -			
Property, plant and equipment acquired with accrued liabilities	$52,584	$59,811	$35,556
Increase (decrease) in capitalized assets associated with asset retirement obligations	$(5,634)	$1,235	$5,743
Cash (paid) refunded during the period for continuing operations-			
Interest (net of amount capitalized)	$(69,239)	$(108,361)	$(116,593)
Income taxes, net	$(413)	$(4,573)	$(3,027)

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(17) EMPLOYEE BENEFIT PLANS

Defined Contribution Plans

We sponsor a 401(k) retirement savings plan (the 401(k) Plan). Participants in the 401(k) Plan may elect to invest a portion of their eligible compensation to the 401(k) Plan up to the maximum amounts established by the IRS. The 401(k) Plan provides employees the opportunity to invest up to 50% of their eligible compensation on a pre-tax or after-tax basis. The 401(k) Plan provides a Company Matching Contribution for all eligible participants and for certain eligible participants a Company Retirement Contribution based on the participant's age and years of service. Vesting of all Company contributions ranges from immediate vesting to graduated vesting at 20% per year with 100% vesting when the participant has 5 years of service with the Company.

Funded Status of Benefit Plans

The funded status of postretirement benefit plans is required to be recognized in the statement of financial position. The funded status for pension plans is measured as the difference between the projected benefit obligation and the fair value of plan assets. The funded status for all other benefit plans is measured as the difference between the accumulated benefit obligation and the fair value of plan assets. A liability is recorded for an amount by which the benefit obligation exceeds the fair value of plan assets or an asset is recorded for any amount by which the fair value of plan assets exceeds the benefit obligation. Except for our regulated utilities, the unrecognized net periodic benefit cost is recorded within Accumulated other comprehensive income (loss), net of tax. For our regulated utilities, these costs are recoverable in our rates, and accordingly, the unrecognized net periodic benefit cost was alternatively recorded as a regulatory asset or regulatory liability, net of tax (see Note 1). The measurement date for all plans is December 31, 2014. As of December 31, 2014, the unfunded status of our Defined Benefit Pension Plans was $78 million; the unfunded status of our Supplemental Non-qualified Defined Benefit Plans was $41 million; and the unfunded status of our Non-pension Defined Benefit Postretirement Healthcare Plans was $44 million.

Defined Benefit Pension Plans (Pension Plans)

We have two defined benefit pension plans. Our BHC Pension Plan covers certain eligible employees of Black Hills Service Company, Black Hills Power, WRDC, BHEP and Cheyenne Light. The Black Hills Utility Holdings, Inc. Pension Plan covers certain eligible employees of Black Hills Energy. The benefits for the Pension Plans are based on years of service and calculations of average earnings during a specific time period prior to retirement. Both Pension Plans have been frozen to new employees and certain employees who did not meet age and service based criteria.

Pension Plan assets are held in a Master Trust. Each Plan holds an undivided interest in the Master Trust. Our Board of Directors has approved the Plans' investment policy. The objective of the investment policy is to manage assets in such a way that will allow the eventual settlement of our obligations to the Pension Plans' beneficiaries. To meet this objective, our pension assets are managed by an outside adviser using a portfolio strategy that will provide liquidity to meet the Plans' benefit payment obligations. The Pension Plans' assets consist primarily of equity, fixed income and hedged investments. The expected long-term rate of return for investments was 6.75% and 7.25% for the 2014 and 2013 plan years, respectively. Our Pension Plan funding policy is in accordance with the federal government's funding requirements.

In 2011, the Cheyenne Light Pension Plan was amended to freeze the benefits of certain bargaining unit employees. This amendment was effective as of January 1, 2012. Additionally, effective October 1, 2012, the Cheyenne Light Pension Plan was merged into the BHC Pension Plan. The Pension Plan benefits are based on years of service and compensation levels.

Plan Assets

The percentages of total plan asset fair value by investment category for our Pension Plans at December 31 were as follows:

	2014		2013	
Equity	27	%	26	%
Real estate	5		4	
Fixed income	58		58	
Cash	2		1	
Hedge funds	8		11	
Total	100	%	100	%

Supplemental Non-qualified Defined Benefit Plans

We have various supplemental retirement plans for key executives of the Company. The plans are non-qualified defined benefit and defined contribution plans (Supplemental Plans). The Supplemental Plans are subject to various vesting schedules and are not funded by the Company.

Plan Assets

We do not fund our Supplemental Plans. We fund on a cash basis as benefits are paid.

Non-pension Defined Benefit Postretirement Healthcare Plans

We sponsor three retiree healthcare plans (Healthcare Plans) for employees who meet certain age and service requirements at retirement. Healthcare Plan benefits are subject to premiums, deductibles, co-payment provisions and other limitations. A portion of the Healthcare Plans is pre-funded via VEBAs. Effective January 1, 2014, health care coverage for Medicare-eligible retirees will be provided through an individual market health care exchange for BHC and Black Hills Utility Holdings retirees.

Plan Assets

We fund the Healthcare Plans on a cash basis as benefits are paid. The Black Hills Energy Plan provides for partial pre-funding via VEBAs. Assets related to this pre-funding are held in trust and are for the benefit of the union and non-union employees of Black Hills Energy located in the states of Kansas and Iowa. We do not pre-fund the Postretirement Healthcare Plans for those employees outside Kansas and Iowa.

Plan Contributions

Contributions to the Pension Plans are cash contributions made directly to the Pension Plan Trust accounts. Healthcare and Supplemental Plan contributions are made in the form of benefit payments. Contributions for the years ended December 31 were as follows (in thousands):

	2014	2013
Defined Contribution Plan		
Company Retirement Contribution	$4,187	$2,775
Matching contributions - Defined Contribution Plans	$9,254	$8,524

	2014	2013
Defined Benefit Plans		

Defined Benefit Pension Plans	$10,200	$12,500
Non-Pension Defined Benefit Postretirement Healthcare Plans	$3,163	$5,123
Supplemental Non-Qualified Defined Benefit Plans	$1,553	$1,345

While we do not have required contributions, we expect to make approximately $10 million in contributions to our Defined Benefit Pension Plans in 2015.

Fair Value Measurements

As required by accounting standards for Compensation - Retirement Benefits, assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect their placement within the fair value hierarchy levels.

The following tables set forth, by level within the fair value hierarchy, the assets that were accounted for at fair value on a recurring basis (in thousands):

Defined Benefit Pension Plans	December 31, 2014			
	Level 1	Level 2	Level 3	Total
AXA Equitable General Fixed Income	$—	$541	$—	$541
Common Collective Trust - Cash and Cash Equivalents	—	4,013	—	4,013
Common Collective Trust - Equity	—	81,636	—	81,636
Common Collective Trust - Fixed Income	—	174,726	—	174,726
Common Collective Trust - Real Estate	—	3,864	9,719	13,583
Hedge Funds	—	—	25,034	25,034
Total investments measured at fair value	$—	$264,780	$34,753	$299,533

Defined Benefit Pension Plans	December 31, 2013			
	Level 1	Level 2	Level 3	Total
AXA Equitable General Fixed Income	$—	$1,056	$—	$1,056
Common Collective Trust - Cash and Cash Equivalents	—	1,253	—	1,253
Common Collective Trust - Equity	—	73,726	—	73,726
Common Collective Trust - Fixed Income	—	162,747	—	162,747
Common Collective Trust - Real Estate	—	3,392	8,541	11,933
Hedge Funds	—	—	29,647	29,647
Total investments measured at fair value	$—	$242,174	$38,188	$280,362

Non-pension Defined Benefit Postretirement Healthcare Plans	December 31, 2014			
	Level 1	Level 2	Level 3	Total
Registered Investment Company Trust - Money Market Mutual Fund	$—	$4,705	$—	$4,705
Total investments measured at fair value	$—	4,705	$—	$4,705

Non-pension Defined Benefit Postretirement Healthcare Plans	December 31, 2013			
	Level 1	Level 2	Level 3	Total
Registered Investment Company Trust - Money Market Mutual Fund	$—	$4,546	$—	$4,546
Total investments measured at fair value	$—	$4,546	$—	$4,546

The following table sets forth a summary of changes in the fair value of the Defined Benefit Pension Plans’ Level 3 assets for the period ended December 31 (in thousands):

	2014	2013
Balance, beginning of period	$38,188	$7,770
Purchase	454	29,000
Unrealized gain (loss)	1,789	1,508
Realized gain (loss)	322	(77)
Settlements	(6,000)	(13)
Balance, end of period	$34,753	$38,188

The following table presents the quantitative information about Level 3 fair value measurements (dollars in thousands):

	Fair Value at December 31, 2014	Valuation Technique	Level 3 Input	Range (Weighted) Average
Assets:				
Common Collective Trust - Real Estate [(a)]	$9,719	Market Approach	Redemption Restriction	N/A
Hedge Funds [(b)]	$25,034	Market Approach	Redemption Restriction	N/A

(a) The underlying net asset value in the Common Collective Trust - Real Estate fund is determined by appraisal of the properties held in the Trust. As part of the Trustee's valuation process, properties are externally appraised generally on an annual basis. The appraisals are conducted by reputable independent appraisal firms and signed by appraisers that are members of the Appraisal Institute, with the professional designation of Member, Appraisal Institute. All external appraisals are performed in accordance with the Uniform Standards of Professional Appraisal Practices. We receive monthly statements from the Trustee along with the annual schedule of investments and rely on these reports for pricing the units of the fund. The fund does contain a participant withdrawal policy.

(b) The fair value of the Hedge Funds is determined based on pricing provided or reviewed by the third-party administrator to our investment managers. While the input amounts used by the pricing vendor in determining fair value are not provided, and therefore, unavailable for our review, the asset results are reviewed and monitored to ensure the fair values are reasonable and in line with market experience in similar asset classes. Additionally, the audited financial statements of the funds are reviewed at the time they are issued.

Additional information about assets of the Pension Plans, including methods and assumptions used to estimate the fair value of these assets, is as follows:

AXA Equitable General Fixed Income Fund: This fund is a diversified portfolio, primarily composed of fixed income instruments. Assets are invested in long-term holdings, such as commercial, agricultural and residential mortgages, publicly traded and privately place bonds and real estate as well as short-term bonds. Fair values of mortgage loans are measured by discounting future contractual cash flows to be received on the mortgage loans using interest rates at which loans with similar characteristics have. The discount rate is derived from taking the appropriate U.S. Treasury rate with a like term. The fair value of public fixed maturity securities are generally based on prices obtained from independent valuation service providers with reasonableness prices compared with directly observable market trades. The fair value of privately placed securities are determined using a discounted cash flow model. These models use observable inputs with a discount rate based upon the average of spread surveys collected from private market intermediaries and industry sector of the issuer.

Common Collective Trust Funds: These funds are valued based upon the redemption price of units held by the Plan, which is based on the current fair value of the common collective trust funds' underlying assets. Unit values are determined by the financial institution sponsoring such funds by dividing the fund's net assets at fair value by its units outstanding at the valuation dates. The Plan's investments in common collective trust funds, with the exception of shares of the common collective trust-real estate are categorized as Level 2.

Common Collective Trust-Real Estate Fund: This fund is valued based on various factors of the underlying real estate properties, including market rent, market rent growth, occupancy levels, etc. As part of the trustee's valuation process, properties are externally appraised generally on an annual basis. The appraisals are conducted by reputable independent appraisal firms and signed by appraisers that are members of the Appraisal Institute, with professional designation of Member, Appraisal Institute. All external appraisals are performed in accordance with the Uniform Standards of Professional Appraisal Practices. We receive monthly statements from the trustee, along with the annual schedule of investments, and rely on these reports for pricing the units of the fund. Certain of the funds' assets contain participant withdrawal policy and, therefore, are categorized as Level 3. The funds without participant withdrawal limitations are categorized as Level 2.
Hedge Funds: Hedge funds represent investments in other investment funds that seek a return utilizing a number of diverse investment strategies. The strategies, when combined aim to reduce volatility and risk while attempting to deliver positive returns under all market conditions. Amounts are reported on a one-month lag. The fair value of hedge funds is determined using net asset value per share based on the fair value of the hedge fund's underlying investments. Generally, shares may be redeemed at the end of each quarter, with a 65 day notice and are limited to a percentage of total net asset value of the fund. The net asset values are based on the fair value of each fund's underlying investments. There are no unfunded commitments related to these hedge funds. The Plan's investment in the hedge fund is categorized as Level 3.
Other Plan Information

The following tables provide a reconciliation of the employee benefit plan obligations, fair value of assets and amounts recognized in the statement of financial position, components of the net periodic expense and elements of accumulated other comprehensive income (in thousands):

Benefit Obligations

		Defined Benefit Pension Plans		Supplemental Non-qualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
		2014	2013	2014	2013	2014	2013
Change in benefit obligation:							
Projected benefit obligation at beginning of year		$321,400	363,235	$32,960	$34,393	$45,778	$46,681
Service cost		5,448	6,433	2,543	1,392	1,700	1,674
Interest cost		15,852	15,300	1,447	1,328	1,919	1,669
Actuarial (gain) loss	(a)	55,384	(38,252)	5,814	(2,808)	2,275	(3,379)
Amendments (b)		—	—	—	—	—	1,585
Benefits paid	(c)	(20,312)	(25,316)	(1,553)	(1,345)	(3,163)	(5,123)
Medicare Part D accrued		—	—	—	—	(99)	470
Plan participants' contributions		—	—	—	—	632	2,201
Projected benefit obligation at end of year		$377,772	$321,400	$41,211	$32,960	$49,042	$45,778

(a) Change from 2013 reflects a decrease in the discount rate and a change in the mortality tables used in employee benefit plan estimates.
(b) Reflects Board of Directors approval of an increase to Company's contribution to RMSA accounts.
(c) Benefits paid include payments made to terminated vested employees who elected lump-sum offerings of $6.1 million in 2014 and $13 million in 2013.

A reconciliation of the fair value of Plan assets was as follows (in thousands):

	Defined Benefit Pension Plans		Supplemental Non-qualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans [a]	
	2014	2013	2014	2013	2014	2013
Beginning market value of plan assets	$280,362	$268,816	$—	$—	$4,546	$4,351
Investment income (loss)	29,283	24,362	—	—	(43)	8
Employer contributions	10,200	12,500	—	—	2,733	1,923
Retiree contributions	—	—	—	—	632	1,533
Benefits paid	(20,312)	(25,316) [b]	—	—	(3,163)	(3,269)
Plan administrative expenses	—	—	—	—	—	—
Ending market value of plan assets	$299,533	$280,362	$—	$—	$4,705	$4,546

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(a) Assets of VEBA.

(b) Benefits paid include payments made to terminated vested employees who elected a lump-sum offering of $6.1 million in 2014 and $13 million in 2013.

Amounts recognized in the Consolidated Balance Sheets at December 31 consist of (in thousands):

	Defined Benefit Pension Plans		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2014	2013	2014	2013	2014	2013
Regulatory assets	$78,864	$48,419	$—	$—	$7,137	$5,535
Current liabilities	$—	$—	$1,486	$1,491	$3,273	$2,802
Non-current liabilities	$78,239	$41,034	$39,725	$32,033	$41,002	$38,412
Regulatory liabilities	$—	$—	$—	$—	$2,983	$3,141

Accumulated Benefit Obligation

(in thousands)	Defined Benefit Pension Plans		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2014	2013	2014	2013	2014	2013
Accumulated benefit obligation - Black Hills Corporation	$135,582	$110,847	$29,843	$27,380	$12,809	$12,101
Accumulated benefit obligation - Black Hills Energy	213,398	182,295	386	513	25,456	25,467
Accumulated benefit obligation - Cheyenne Light	—	—	—	—	10,777	8,210
Total Accumulated Benefit Obligation	$348,980	$293,142	$30,229	$27,893	$49,042	$45,778

Components of Net Periodic Expense

(in thousands)	Defined Benefit Pension Plans			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plans		
	2014	2013	2012	2014	2013	2012	2014	2013	2012
Service cost	$5,448	$6,433	$5,720	$1,498	$1,392	$889	$1,700	$1,674	$1,610
Interest cost	15,852	15,300	14,747	1,447	1,328	1,410	1,919	1,669	2,093
Expected return on assets	(18,065)	(18,615)	(16,334)	—	—	—	(85)	(79)	(78)
Amortization of prior service cost	62	63	89	2	2	3	(428)	(500)	(500)
Recognized net actuarial loss (gain)	4,806	12,250	9,630	498	793	807	160	482	887
Net periodic expense	$8,103	$15,431	$13,852	$3,445	$3,515	$3,109	$3,266	$3,246	$4,012

Accumulated Other Comprehensive Income

In accordance with accounting standards for defined benefit plans, amounts included in Accumulated other comprehensive income (loss), after-tax, that have not yet been recognized as components of net periodic benefit cost at December 31 were as follows (in thousands):

	Defined Benefit Pension Plans		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2014	2013	2014	2013	2014	2013
Net (gain) loss	$10,996	$4,842	$8,396	$4,939	$1,904	$1,648
Prior service cost (gain)	51	64	8	9	(1,218)	(1,213)
Total accumulated other comprehensive (income) loss	$11,047	$4,906	$8,404	$4,948	$686	$435

The amounts in Accumulated other comprehensive income (loss), Regulatory assets or Regulatory liabilities, after-tax, expected to be recognized as a component of net periodic benefit cost during calendar year 2015 are as follows (in thousands):

	Defined Benefit Pension Plans	Supplemental Non-qualified Defined Benefit Plans	Non-pension Defined Benefit Postretirement Healthcare Plans
Net loss	$7,174	$703	$295
Prior service cost (credit)	38	1	(278)
Total net periodic benefit cost expected to be recognized during calendar year 2015	$7,212	$704	$17

Assumptions

	Defined Benefit Pension Plans			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plans		
Weighted-average assumptions used to determine benefit obligations:	2014	2013	2012	2014	2013	2012	2014	2013	2012
Discount rate	4.20 %	5.05 %	4.30 %	3.64 %	4.21 %	3.44 %	3.92 %	4.62 %	3.85 %

Rate of increase in compensation levels	3.78 %	3.78 %	3.84 %	5.00 %	5.00 %	5.00 %	N/A	N/A	N/A

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	Defined Benefit Pension Plans			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plans		
Weighted-average assumptions used to determine net periodic benefit cost for plan year:	2014	2013	2012	2014	2013	2012	2014	2013	2012
Discount rate:									
Black Hills Corporation	5.10 %	4.35 %	4.68 %	4.68 %	3.88 %	4.70 %	4.45 %	3.65 %	4.35 %
Black Hills Energy	5.00 %	4.25 %	4.60 %	3.75 %	3.00 %	3.90 %	4.25 %	3.50 %	4.35 %
Cheyenne Light	N/A	N/A	N/A	N/A	N/A	N/A	5.15 %	4.40 %	4.65 %
Expected long-term rate of return on assets [(a)]	6.75 %	7.25 %	7.25 %	N/A	N/A	N/A	2.00 %	2.00 %	2.00 %
Rate of increase in compensation levels	3.78 %	3.78 %	3.75 %	5.00 %	5.00 %	5.00 %	N/A	N/A	N/A

(a) The expected rate of return on plan assets is 6.75% for the calculation of the 2015 net periodic pension cost.

The healthcare benefit obligation was determined at December 31 as follows:

	Black Hills Corporation	Black Hills Energy	Cheyenne Light
2014			
Healthcare trend rate pre-65			
Trend for next year	7.50 %	7.50 %	7.50 %
Ultimate trend rate	4.50 %	4.50 %	4.50 %
Year Ultimate Trend Reached	2027	2027	2027
Healthcare trend rate post-65			
Trend for next year	6.25 %	6.25 %	6.25 %
Ultimate trend rate	4.50 %	4.50 %	4.50 %
Year Ultimate Trend Reached	2024	2024	2024
2013			
Healthcare trend rate pre-65			
Trend for next year	7.50 %	7.50 %	7.50 %
Ultimate trend rate	4.50 %	4.50 %	4.50 %
Year Ultimate Trend Reached	2027	2027	2027
Healthcare trend rate post-65			
Trend for next year	6.25 %	6.25 %	6.25 %
Ultimate trend rate	4.50 %	4.50 %	4.50 %
Year Ultimate Trend Reached	2026	2026	2026

We do not pre-fund our non-qualified pension plans or two of the three postretirement benefit plans. The table below shows the expected impacts of an increase or decrease to our healthcare trend rate for our Retiree Healthcare Plans (in thousands):

Change in Assumed Trend Rate	Impact on December 31, 2014 Accumulated Postretirement Benefit Obligation	Impact on 2014 Service and Interest Cost
Increase 1%	$2,635	$168
Decrease 1%	$(2,166)	$(136)

The following benefit payments, which reflect future service, are expected to be paid (in thousands):

	Defined Benefit Pension Plans	Supplemental Non-qualified Defined Benefit Plan	Non-Pension Defined Benefit Postretirement Healthcare Plans
2015	$14,712	$1,486	$3,921
2016	$15,629	$1,573	$4,011
2017	$16,561	$1,627	$4,057
2018	$17,556	$1,670	$4,169
2019	$18,741	$1,780	$4,236
2020-2024	$109,147	$8,901	$19,877

(18) COMMITMENTS AND CONTINGENCIES

Power Purchase and Transmission Services Agreements

Through our subsidiaries, we have the following significant long-term power purchase contracts with non-affiliated third-parties:

- Black Hills Wyoming sold its CTII 40 MW natural gas-fired generating unit to the City of Gillette, Wyoming on September 3, 2014. Under the terms of the sale, Black Hills Wyoming entered into ancillary agreements to operate CTII, provide use of shared facilities including a ground lease and dispatch generation services. In addition, the agreement includes a 20-year economy energy PPA that contains a sharing arrangement in which the parties share the savings of wholesale power purchases made when market power prices are less than the cost of operating the generating unit.

- Black Hills Power's PPA with PacifiCorp, expiring December 31, 2023, for the purchase of 50 MW of electric capacity and energy from PacifiCorp's system. The price paid for the capacity and energy is based on the operating costs of one of PacifiCorp's coal-fired electric generating plants.

- Black Hills Power has a firm point-to-point transmission service agreement with PacifiCorp that expires December 31, 2023. The agreement provides 50 MW of capacity and energy to be transmitted annually by PacifiCorp.

- Cheyenne Light's PPA with Duke Energy's Happy Jack wind site, expiring September 3, 2028, provides up to 30 MW of wind energy from Happy Jack to Cheyenne Light. Under a separate inter-company agreement, Cheyenne Light sells 50% of the facility output to Black Hills Power.

- Cheyenne Light's PPA with Duke Energy's Silver Sage wind site, expiring September 30, 2029, provides up to 30 MW of wind energy. Under a separate inter-company agreement, Cheyenne Light has agreed to sell 20 MW of energy from Silver Sage to Black Hills Power.

- Colorado Electric's PPA with Cargill expiring on December 31, 2015, which provides for the purchase of 50 MW energy during heavy load timing intervals.

- Colorado Electric's PPA with Cargill expiring on December 31, 2016, which provides for the purchase of 50 MW energy during light load timing intervals.

- Colorado Electric's REPA with AltaGas expiring October 16, 2037, provides up to 14.5 MW of wind energy from the Busch Ranch Wind Project in which Colorado Electric owns a 50% undivided ownership interest.

Costs under these power purchase contracts for the years ended December 31 were as follows (in thousands):

	2014	2013	2012
PPA with PacifiCorp	$13,943	$13,026	$13,224
Transmission services agreement with PacifiCorp	$1,227	$1,384	$1,215
PPA with Happy Jack	$3,919	$3,772	$1,988
PPA with Silver Sage	$4,798	$4,809	$3,269
Busch Ranch Wind Project	$1,998	$1,856	$502
PPAs with Cargill [(a)]	$9,286	$12,291	$14,236

(a) The 2013 and 2012 PPAs were one year contracts replaced by subsequent one year contracts upon expiration.

Other Gas Supply Agreements

Our Utilities also purchase natural gas, including transportation capacity to meet customers' needs, under short-term and long-term purchase contracts. These contracts extend to 2017.

Natural Gas Delivery Commitment

In 2012, we entered into a ten-year gas gathering and processing contract for natural gas production from our properties in the Piceance Basin in Colorado, under which we pay a gathering fee per Mcf. This take or pay contract requires us to pay the fee on a minimum of 20,000 Mcf per day, regardless of the volume delivered. The ten-year agreement expiring in 2024 became effective in first quarter of 2014 upon completion of the processing infrastructure capable of handling the committed volumes.

Future Minimum Payments

The following is a schedule of future minimum payments required under the power purchase, transmission services, coal and gas supply agreements and natural gas delivery commitments (in thousands):

2015	$183,116
2016	$131,716
2017	$121,867
2018	$69,000
2019	$35,905
Thereafter	$153,395

Future Purchase Agreement - Related Party

Cheyenne Light's PPA for 60 MW of capacity and energy from Black Hills Wyoming's Wygen I generating facility expiring on December 31, 2022, includes an option for Cheyenne Light to purchase Black Hills Wyoming's ownership in the
Wygen I facility. The purchase price related to the option is $2.6 million per MW which is the equivalent per MW of the pre-construction estimated cost of the Wygen III plant, which was completed in April 2010. This option purchase price is adjusted for capital additions and reduced by an amount equal to annual depreciation based on a 35-year life starting January 1, 2009.

Power Sales Agreements

Through our subsidiaries, we have the following significant long-term power sales contracts with non-affiliated third-parties:

- During periods of reduced production at Wygen III in which MDU owns a portion of the capacity, or during periods when Wygen III is off-line, MDU will be provided with 25 MW from our other generation facilities or from system purchases with reimbursement of costs by MDU.

- Black Hills Power has an agreement to serve MDU capacity and energy up to a maximum of 50 MW in excess of Wygen III ownership.

- During periods of reduced production at Wygen III in which the City of Gillette owns a portion of the capacity, or during periods when Wygen III is off-line, we will provide the City of Gillette with its first 23 MW from our other generating facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement, Black Hills Power will also provide the City of Gillette their operating component of spinning reserves.

- Black Hills Power has a PPA with MEAN expiring April 1, 2015. Under this contract, MEAN purchases 5 MW of unit-contingent capacity from Neil Simpson II and 5 MW of unit-contingent capacity from Wygen III.

- Black Hills Power has a PPA with MEAN expiring May 31, 2023. This contract is unit-contingent on up to 10 MW from Neil Simpson II and up to 10 MW from Wygen III based on the availability of these plants. The capacity purchase requirements decrease over the term of the agreement.

Purchase Commitment

On October 14, 2014, we announced an agreement to acquire Energy West Wyoming, Inc., a Wyoming gas utility, and pipeline assets of Gas Natural, Inc. for $17 million. The gas utility serves approximately 6,700 customers, including service to Cody, Ralston and Meeteetse, Wyoming. The pipeline assets include a 30 mile gas transmission pipeline and a 42 mile gas gathering pipeline, both located near the utility service territory. This purchase is expected to be completed in 2015.

Related Party Lease

Colorado Electric's PPA with Black Hills Colorado IPP expiring on December 31, 2031, provides 200 MW of power to Colorado Electric from Black Hills Colorado IPP's combined-cycle turbines. This PPA is accounted for as a capital lease whereby Colorado Electric, as lessee, has included the combined-cycle turbines as property, plant and equipment along with the related lease obligation and Black Hills Colorado IPP, as lessor, has recorded a lease receivable. Segment revenue and expenses associated with the PPA have been impacted by the lease accounting. The effect of the lease accounting is eliminated in corporate consolidations.

Reimbursement Agreement

We have a reimbursement agreement in place with Wells Fargo on behalf of Cheyenne Light for the 2009A bonds of $10 million due in 2027 and the 2009B bonds of $7.0 million due in 2021. In the case of default, we hold the assumption of liability for drawings on Cheyenne Light's Letter of Credit attached to these bonds.

Environmental Matters

We are subject to costs resulting from a number of federal, state and local laws and regulations which affect future planning and existing operations. They can result in increased capital expenditures, operating and other costs as a result of compliance, remediation and monitoring obligations. Due to the environmental issues discussed below, we may be required to modify, curtail, replace or cease operating certain facilities or operations to comply with statutes, regulations and other requirements of regulatory bodies.

Air

Our generation facilities are subject to federal, state and local laws and regulations relating to the protection of air quality. These laws and regulations cover, among other pollutants, carbon monoxide, SO_2, NO_x, mercury particulate matter and GHG. Power generating facilities burning fossil fuels emit each of the foregoing pollutants and, therefore, are subject to substantial regulation and enforcement oversight by various governmental agencies.

Title IV of the Clean Air Act applies to several of our generation facilities, including the Neil Simpson II, Neil Simpson CT, Lange CT, Wygen I, Wygen II, Wygen III, Wyodak and Pueblo Airport Generating Station plants. Title IV of the Clean Air Act created an SO_2 allowance trading program as part of the federal acid rain program. Without purchasing additional allowances, we currently hold sufficient allowances to satisfy Title IV at all such plants through 2044.

The EPA issued the Industrial and Commercial Boiler Regulations for Area Sources of Hazardous Air Pollutants, with updates which impose emission limits, fuel requirements and monitoring requirements. The rule had a compliance deadline of March 21, 2014. In anticipation of this rule we suspended operations at the Osage plant in October 2010 and as a result of this rule, we suspended operations at the Ben French facility on August 31, 2012. We permanently retired Ben French, Osage and Neil Simpson I on March 21, 2014. In conjunction with the Colorado Clean Air Clean Jobs Act, the CPUC issued an order approving the closure of the W.N. Clark facility no later than December 31, 2013. This facility suspended operations December 31, 2012 and was retired on December 31, 2013. The net book value of these plants was allowed regulatory accounting treatment and is recorded as a Regulatory Asset on the Consolidated Balance Sheet. The CPUC also approved a CPCN for the retirement of Pueblo Units #5 and #6 effective December 31, 2013.

Solid Waste Disposal

Various materials used at our facilities are subject to disposal regulations. Our Osage plant, permanently retired on March 21, 2014, had an on-site ash impoundment that was near capacity. An application to close the impoundment was approved on April 13, 2012. Site closure work was completed in 2013 with the state providing closure certification in 2014. Post closure monitoring activities will continue for 30 years.

In September 2013, Osage also received a permit to close the small industrial rubble landfill. Site work was completed with the state providing closure certification in 2014. Post closure monitoring will continue for 30 years.

Our W.N. Clark plant, which has been retired, previously delivered coal ash to a permitted, privately-owned landfill. While we do not believe that any substances from our solid waste disposal activities will pollute underground water, we can provide no assurance that pollution will not occur over time. In this event, we could incur material costs to mitigate any resulting damages.

Reclamation Liability

For our Pueblo Airport Generation site, we posted a bond of $3.9 million with the State of Colorado to cover the costs of remediation for a waste water containment pond permitted to provide wastewater storage and processing for this zero discharge facility. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land.

Under its land lease for Busch Ranch, Colorado Electric is required to reclaim all land where it has placed wind turbines. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land.

Under its mining permit, WRDC is required to reclaim all land where it has mined coal reserves. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land.

See Note 7 for additional information.

Manufactured Gas Processing

As a result of the Aquila Transaction, we acquired whole and partial liabilities for several former manufactured gas processing sites in Nebraska and Iowa which were previously used to convert coal to natural gas. The acquisition provided for an insurance recovery, now valued at $1.3 million recorded in Other assets, non-current on our Consolidated Balance Sheets, which will be used to help offset remediation costs. The remediation cost estimate could change materially due to results of further investigations, actions of environmental agencies or the financial viability of other responsible parties.

In March 2011, Nebraska Gas executed an Allocation, Indemnification and Access Agreement with the successor to the former operator of the Nebraska MGPs. Under this agreement, Nebraska Gas agreed to remediate the Blair and Plattsmouth sites in Nebraska. Subsequent to this transaction, Nebraska Gas enrolled Blair and Plattsmouth in Nebraska's Voluntary Cleanup Program. Site remediation was completed in September 2012, however there is a potential for additional minimal remediation work at Plattsmouth where monitoring is required until 2015. Both Nebraska sites will be required to monitor groundwater quality for a minimum two year period, ending in 2015.

As of December 31, 2014, our estimated liabilities for all of the MGP sites currently range from approximately $2.7 million to $6.3 million for which we had $2.7 million accrued for remediation of sites as of December 31, 2014 included in Other deferred credits and other liabilities on our Consolidated Balance Sheets.

Prior to Black Hills Corporation's ownership, Aquila received rate orders that enabled recovery of environmental cleanup costs in certain jurisdictions. We anticipate recovery of these current and future costs would be allowed. Additionally, we may pursue recovery or agreements with other potentially responsible parties when and where permitted.

Legal Proceedings

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in the consolidated financial statements to satisfy alleged liabilities are adequate in light of the probable and estimable contingencies. However, there can be no assurance that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims and other matters discussed, and to comply with applicable laws and regulations will not exceed the amounts reflected in the consolidated financial statements.

In the normal course of business, we enter into agreements that include indemnification in favor of third parties, such as information technology agreements, purchase and sale agreements and lease contracts. We have also agreed to indemnify our directors, officers and employees in accordance with our articles of incorporation, as amended. Certain agreements do not contain any limits on our liability and therefore, it is not possible to estimate our potential liability under these indemnifications. In certain cases, we have recourse against third parties with respect to these indemnities. Further, we maintain insurance policies that may provide coverage against certain claims under these indemnities.

Oil Creek Fire

On June 29, 2012, a forest and grassland fire occurred in the western Black Hills of Wyoming. A fire investigator retained by the Weston County Fire Protection District concluded that the fire was caused by the failure of a transmission structure owned, operated and maintained by Black Hills Power. On April 16, 2013, a large group of private landowners filed suit in the United States District Court for the District of Wyoming. There are approximately 36 Plaintiff groups (including property jointly owned by multiple family members or entities), or approximately 73 individually named private plaintiffs. In addition, the State of Wyoming has intervened in the lawsuit. Both the private landowners and the State of Wyoming assert claims for damages against Black Hills Power. The claims include allegations of negligence, negligence per se, common law nuisance and trespass. In addition to claims for compensatory damages, the lawsuit seeks recovery of punitive damages. We have denied and will vigorously defend all claims arising out of the fire. We cannot predict the outcome of our investigation, the viability of alleged claims or the outcome of the litigation.

Civil litigation of this kind, however, is likely to lead to settlement negotiations, including negotiations prompted by pre-trial civil court procedures. We believe such negotiations would effect a settlement of all claims. Regardless of whether the litigation is determined at trial or through settlement, we expect to incur significant investigation, legal and expert services expenses associated with the litigation. We maintain insurance coverage to limit our exposure to losses due to civil liability claims, and related litigation expense. We expect this coverage to limit our exposure and we will pursue recoveries to the maximum extent available under the policies. The deductible applicable to some types of claims arising out of this fire is $1.0 million. Based upon information currently available, we believe that a loss associated with settlement of pending claims is probable. Accordingly, as of September 30, 2014, we recorded a loss contingency liability related to these claims and we recorded a receivable for costs we believe are reimbursable and probable of recovery under our insurance coverage. Both of these entries reflect our reasonable estimate of probable future litigation expense and settlement costs; we did not base these contingencies on any determination that it is probable we would be found liable for these claims were they to be litigated.

Given the uncertainty of litigation, however, a loss related to the fire, the litigation and related claims in excess of the loss we have determined to be probable is reasonably possible. We cannot reasonably estimate the amount of such possible loss because our investigation and review of damage claims documentation is ongoing, and there are significant factual and legal issues to be resolved. Further claims may be presented by these claimants and other parties. We have received claims seeking recovery for fire suppression, reclamation and rehabilitation costs, damage to fencing and other personal property, alleged injury to timber, grass or hay, livestock and related operations, and diminished value of real estate, currently totaling $55 million. We are not yet able to reasonably estimate the amount of any reasonable possible losses in excess of the amount we have accrued. Based upon information currently available, however, management does not expect the outcome of the claims to have a material adverse effect upon our consolidated financial condition, results of operations or cash flows.

(19) GUARANTEES

We have entered into various agreements providing financial or performance assurance to third parties on behalf of certain of our subsidiaries. The agreements include indemnification for reclamation and surety bonds.

We had the following guarantees in place as of (in thousands):

Nature of Guarantee	Maximum Exposure at December 31, 2014	Expiration
Indemnification for subsidiary reclamation/surety bonds [(a)]	$63,900	Ongoing

(a) We have guarantees in place for reclamation and surety bonds for our subsidiaries. The guarantees were entered into in the normal course of business. To the extent liabilities are incurred as a result of activities covered by the surety bonds, such liabilities are included in our Consolidated Balance Sheets.

During the second quarter of 2014, guarantees of Black Hills Utility Holdings' payment obligations up to $70 million arising from commodity transactions for natural gas supply were removed, primarily due to improvement of the corporate credit rating, as well as the conversion of certain guarantees to letters of credit.

(20) OIL AND GAS RESERVES (Unaudited)

BHEP has operating and non-operating interests in 1,205 gross developed oil and gas wells in 10 states and holds leases on approximately 240,816 net acres.

Costs Incurred

Following is a summary of costs incurred in oil and gas property acquisition, exploration and development during the years ended December 31 (in thousands):

	2014	2013	2012
Acquisition of properties:			
Proved	$4,881	$234	$2,437
Unproved	5,056	6,022	33,052
Exploration costs	54,355	12,817	115
Development costs	52,262	48,641	73,877
Asset retirement obligations incurred	68	143	158
Total costs incurred	$116,622	$67,857	$109,639

Reserves

The following table summarizes BHEP’s quantities of proved developed and undeveloped oil, natural gas and NGL reserves, estimated using SEC-defined product prices, as of December 31, 2014, 2013 and 2012 and a reconciliation of the changes between these dates. These estimates are based on reserve reports by CG&A. Such reserve estimates are inherently imprecise and may be subject to revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions.

Minor differences in amounts may result in the following tables relating to oil and gas reserves due to rounding.

	2014			2013		2012	
	Oil	Gas	NGL	Oil	Gas	Oil	Gas
	(in Mbbls of oil and NGL, and MMcf of gas)						
Proved developed and undeveloped reserves:							
Balance at beginning of year	3,921	63,190	—	4,116	55,985	6,223	95,904
Production [a]	(337)	(7,156)	(135)	(336)	(6,984)	(560)	(8,686)
Additions - acquisitions (sales) [b]	(40)	(61)	—	(30)	(46)	(2,025)	(3,070)
Additions - extensions and discoveries	733	11,003	182	379	10,456	449	2,898
Revisions to previous estimates	(1)	(1,536)	1,673	(208)	3,779	29	(31,061)
Balance at end of year	4,276	65,440	1,720	3,921	63,190	4,116	55,985
Proved developed reserves at end of year included above	3,780	57,427	1,530	3,689	60,224	3,929	55,708
Proved undeveloped reserves at the end of year included in above	496	8,013	191	232	2,966	187	279
NYMEX prices	$94.99	$4.35	$— [c]	$96.94	$3.67	$94.71	$2.76
Well-head reserve prices	$85.80	$3.33	$34.81	$89.79	$3.45	$85.31	$2.24

(a) Production for reserve calculations does not include volumes for natural gas liquids (NGLs) for historical periods.
(b) Reflects the sale of the majority of the Williston Basin assets during 2012.
(c) A specific NYMEX price for NGL is not available. Market prices for NGL are broken down by various liquid components, including ethane, propane, iso butane, normal butane, and natural gasoline. Each of these components is traded as an index. Presently, ethane is not being recovered at any of the facilities that process our natural gas production.

Reserve additions totaled 16.5 Bcfe, replacing 165% of annual production. Reserve additions resulted from drilling in the Piceance, Powder River and Williston Basins. Drilling in the Piceance for Mancos Shale accounted for 12.3 Bcfe, Williston Basin (Bakken Shale) accounted for 0.5 Bcfe and Powder River Basin drilling accounted for 3.7 Bcfe. Capital spending in 2014 was primarily for evaluation drilling in the Piceance for Mancos Shale and development drilling in the Williston Bakken Shale play. Exploratory drilling investments were made to develop oil opportunities. Future capital spending rates are anticipated to be dependent on product prices and success in other future drilling.

In 2014, we had positive revisions of 8.5 Bcfe to previous reserve estimates. Most of the positive revision was the result of reporting natural gas liquids (NGL) in reserves (4.0 Bcfe) and higher equivalent prices of liquids and gas received at the wellhead (2.9 Bcfe). Natural gas in 2013 and prior years was reported wet. We changed our process in 2014 to separate NGL from the wet gas stream, which resulted in an estimated equivalent volume change of 4.0 Bcfe. Most of this change from increased NGL recovery is from the Powder River Finn Field and the Piceance wells. The industry standard multiplication of liquid production by 6 to arrive at the equivalent gas volume results in higher overall equivalent volumes. This is offset by negative revisions of dry natural gas resulting from higher shrink factors during processing of the wet gas to dry gas and NGLs. We will continue to report oil, natural gas and NGL volumes in the future.

Better wellhead performance resulted in an addition of 2.7 Bcfe, most of which was in the Powder River Basin Finn field and from our 2013 Piceance wells. Higher operating costs caused a minor negative revision of 0.1 Bcfe to 2014 year-end reserves. One proved-undeveloped location in the San Juan Basin was dropped (0.9 Bcfe) because of economics. We sold approximately 0.3 Bcfe of Williston Bakken properties in 2014.

SEC regulations require that proved undeveloped (PUD) locations meet the test of being developed within five years of being categorized as proved. In 2014, we had no PUD locations that were required to be dropped because of the five year rule.

Companies are required to include a narrative disclosure of the total quantity of PUD locations at year end, any material changes in PUD locations during the year and investment and progress made in converting the PUD locations to proved developed during the year.

- In 2013, we had 23 gross PUD locations for 4.7 Bcfe; all of the locations were in the Williston, Piceance and San Juan Basins. In 2014, seven locations in the Williston Bakken Shale were drilled and we invested $3.9 million and developed 0.6 Bcfe. One PUD in the San Juan Basin was dropped for economic reasons. Two PUD locations in the Williston Bakken were sold in 2014.

- Thirteen gross PUD locations remain undrilled as of December 31, 2014. The remaining 2013 PUD locations require approximately $10.5 million of future investment, and when drilled will develop approximately 3.2 Bcfe. Twelve locations are in the Williston Bakken and one location is in the Piceance Basin.

- In 2014, we added 21 gross PUD locations for future Williston Bakken, Piceance Mancos and Powder River Basin drilling.

- The number of locations and reconciliation of our proved undeveloped reserve and future development costs in our year-end proved undeveloped reserves as of December 31, 2014 were:

	Proved Reserves (in Bcfe)	Gross PUD Locations	Future Development Costs (in millions)
Existing 2013:			
Williston	1.8	21	$8.6
Piceance	2.3	1	$6.4
San Juan	0.6	1	$0.9
Year End Total 2013	4.7	23	$15.9
Dropped 2013:			
San Juan	(0.6)	(1)	$(0.9)
Drilled in 2014:			
Williston	(0.6)	(7)	$(3.9)
Sold:			
Williston	(0.3)	(2)	$(0.7)
Added in 2014:			
Williston	0.2	18	$1.0
Powder River	2.0	1	$13.0
Piceance	6.7	2	$17.5
	8.9	21	$31.5
Total Proved Undeveloped	12.1	34	$41.9

- None of our PUD locations have been reflected in our reserves for five or more years. Consistent with SEC guidance, these PUD locations will be monitored and reported each year until either drilled or revised.

Capitalized Costs

Following is information concerning capitalized costs for the years ended December 31 (in thousands):

	2014	2013	2012
Unproved oil and gas properties	$75,329	$62,553	$59,526
Proved oil and gas properties	807,518	725,345	662,444
Gross capitalized costs	882,847	787,898	721,970
Accumulated depreciation, depletion and amortization and valuation allowances [(a)]	(578,108)	(555,263)	(534,777)
Net capitalized costs	$304,739	$232,635	$187,193

(a) Reflects the sale of the majority of the Williston Basin assets during 2012 recorded under the full-cost method of accounting.

Results of Operations

Following is a summary of results of operations for producing activities for the years ended December 31 (in thousands):

	2014	2013	2012
Revenue	$55,114	$54,884	$79,072
Production costs	22,155	20,140	23,483
Gain on sale of assets	—	—	(29,129)
Depreciation, depletion and amortization and valuation provisions	26,626	20,611	37,323
Impairment of long-lived assets	—	—	26,868
Total costs	48,781	40,751	58,545
Results of operations from producing activities before tax	6,333	14,133	20,527
Income tax benefit (expense)	(2,185)	(4,876)	(7,082)
Results of operations from producing activities (excluding general and administrative costs and interest costs)	$4,148	$9,257	$13,445

Unproved Properties

Unproved properties not subject to amortization at December 31, 2014, 2013 and 2012 consisted mainly of exploration cost on various existing work-in-progress projects as well as leasehold acquired through significant natural gas and oil property acquisitions and through direct purchases of leasehold. We capitalized approximately $1.0 million, $1.1 million and $0.7 million of interest during 2014, 2013 and 2012, respectively, on significant investments in unproved properties that were not yet included in the amortization base of the full-cost pool. We will continue to evaluate our unevaluated properties; however, the timing of the ultimate evaluation and disposition of the properties has not been determined. We expect the exploration cost listed below to be added to the cost pool in the next year. The table below sets forth the cost of unproved properties excluded from the amortization base as of December 31, 2014 and notes the year in which the associated costs were incurred (in thousands):

	2014	2013	2012	Prior	Total
Leasehold acquisition cost	$16,077	$4,889	$35,823	$13,412	$70,201
Exploration cost	23,954	10,212	—	—	34,166
Capitalized interest	207	748	360	3,813	5,128

Total	$40,238	$15,849	$36,183	$17,225	$109,495

Standardized Measure of Discounted Future Net Cash Flows

Following is a summary of the standardized measure of discounted future net cash flows and changes relating to proved oil and gas reserves for the years ended December 31 (in thousands):

	2014	2013	2012
Future cash inflows	$675,973	$602,501	$502,769
Future production costs	(245,180)	(213,578)	(186,695)
Future development costs, including plugging and abandonment	(45,123)	(40,557)	(8,462)
Future income tax expense	(29,523)	(81,566)	(69,877)
Future net cash flows	356,147	266,800	237,735
10% annual discount for estimated timing of cash flows	(173,125)	(107,375)	(101,632)
Standardized measure of discounted future net cash flows	$183,022	$159,425	$136,103

The following are the principal sources of change in the standardized measure of discounted future net cash flows during the years ended December 31 (in thousands):

	2014	2013	2012
Standardized measure - beginning of year	$159,425	$136,103	$203,357
Sales and transfers of oil and gas produced, net of production costs	(32,139)	(35,932)	(48,905)
Net changes in prices and production costs	(28,544)	15,126	(42,639)
Extensions, discoveries and improved recovery, less related costs	17,582	29,574	19,870
Changes in future development costs	3,195	(12,216)	43,854
Development costs incurred during the period	2,079	3,554	21,931
Revisions of previous quantity estimates	23,722	12,851	(86,277)
Accretion of discount	18,437	15,126	25,509
Net change in income taxes	19,265	(3,892)	36,578
Purchases of reserves	—	—	—
Sales of reserves [(a)]	—	(869)	(37,175)
Standardized measure - end of year	$183,022	$159,425	$136,103

(a) Reflects sale of Williston Basin assets in 2012.

Changes in the standardized measure from “revisions of previous quantity estimates” are driven by reserve revisions, modifications of production profiles and timing of future development. For all years presented, we had minimal net reserve revisions to prior estimates due to performance. Production forecast modifications are generally made at the well level each year through the reserve review process. These production profile modifications are based on incorporation of the most recent production information and applicable technical studies. Timing of future development investments are reviewed each year and are often modified in response to current market conditions for items such as permitting and service availability.

(21) SALE OF OPERATING ASSETS AND DISCONTINUED OPERATIONS

Partial Sale of Electric Utilities Assets

On September 18, 2012, Colorado Electric completed the sale of an undivided 50% ownership interest in the Busch Ranch Wind project for $25 million. Colorado Electric retains the remaining undivided interest and is the operator of this jointly owned facility. Commercial operation of the newly constructed wind farm commenced on October 16, 2012. Colorado Electric will purchase our partner’s interest in the energy produced by the wind farm through a REPA. See Note 18 for further information.

Partial Sale of Oil and Gas Assets

On September 27, 2012, our Oil and Gas segment sold a majority of its Bakken and Three Forks shale assets in the Williston Basin in North Dakota. An effective date of July 1, 2012, was used to determine the sales price.

Our Oil and Gas segment follows the full-cost method of accounting for oil and gas activities. Typically, this methodology does not allow for gain or loss on sale and proceeds from sale are credited against the full cost pool. Gain or loss recognition is allowed when such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. The Williston Basin asset sale significantly altered the relationship and accordingly we recorded a gain of $29 million with the remainder of the proceeds recorded as a reduction in the full cost pool. As a result of the reduction in the full cost pool from the sale of these assets, the depreciation, depletion and amortization rate declined during 2013.

Net cash proceeds, subsequent to the true-up of all post-closing adjustments, were as follows (in thousands):

Cash proceeds received on date of sale	$243,314	
Adjusted for:		
Post close adjustments	2,793	
Transaction adviser fees	(1,400	)
Estimated payment for contractual obligation related to “back-in” fee *	(16,847	)
Net cash proceeds	$227,860	

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* Required payment, triggered by the sale of the property, arising from a contractual obligation contained in the original participation agreement with the property operator.

Discontinued Operations

Results of operations for discontinued operations have been classified as Income from discontinued operations, net of income taxes in the accompanying Consolidated Statements of Income and Consolidated Statements of Cash Flows. For comparative purposes, all prior periods presented have been restated to reflect the reclassification on a consistent basis.

Energy Marketing Segment

On February 29, 2012, we sold the outstanding stock of our Energy Marketing segment, Enserco Energy Inc. The transaction was completed through a stock purchase agreement and certain other ancillary agreements. Net cash proceeds at date of sale were approximately $165 million, subject to final post-closing adjustments. Those proceeds represented $108 million received from the buyer and $58 million of cash retained from Enserco before closing.

The buyer asserted certain purchase price adjustments, some that we accepted, and several that we disputed. The disputed claims were resolved through a binding arbitration decision dated January 17, 2014. We expensed $1.4 million in 2012, relative to purchase price adjustments we accepted through a partial settlement agreement with the buyer, and an additional $1.1 million in 2013 relative to the claims assigned to arbitration. Loss from discontinued operations was $0.9 million for the twelve months ended December 31, 2013. Results for 2013 include the settlement of unresolved purchase price adjustments.

Operating results of the Energy Marketing segment included in Income (loss) from discontinued operations, net of tax on the accompanying Consolidated Statements of Income were as follows (in thousands):

For the Years Ended December 31,	2013	2012
Revenue	$—	$(604)
Pre-tax income (loss) from discontinued operations	—	(6,061)
Pre-tax gain (loss) on sale	(1,391)	(4,184)
Income tax (expense) benefit	507	3,268
Income (loss) from discontinued operations, net of tax [(a)]	$(884)	$(6,977)

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(a) 2012 includes transaction related costs, net of tax, of $2.5 million for the year ended December 31, 2012.

Total indirect corporate costs and inter-segment interest expenses previously allocated to Enserco were not reclassified to discontinued operations in accordance with GAAP and instead have been reclassified to our Corporate segment.

(22) QUARTERLY HISTORICAL DATA (Unaudited)

The Company operates on a calendar year basis. The following tables set forth select unaudited historical operating results and market data for each quarter of 2014 and 2013.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2014				
Revenue	$460,169	$283,237	$272,087	$378,077
Operating income	$89,598	$46,577	$54,404	$69,951
Income (loss) from continuing operations	$48,118	$19,820	$26,836	$34,007
Net income (loss) available for common stock	$48,118	$19,820	$26,836	$34,007
Income (loss) per share - Basic	$1.09	$0.45	$0.60	$0.77
Income (loss) per share - Diluted	$1.08	$0.44	$0.60	$0.76
Dividends paid per share	$0.390	$0.390	$0.390	$0.390
Common stock prices - High	$59.05	$61.41	$62.13	$57.17
Common stock prices - Low	$51.09	$55.23	$47.87	$47.11

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2013				
Revenue	$380,671	$279,826	$259,907	$355,448
Operating income	$79,846	$49,037	$55,566	$71,103
Income (loss) from continuing operations [(a)] [(b)]	$43,197	$30,518	$23,124	$19,007
Income (loss) from discontinued operations	$—	$—	$—	$(884)
Net income (loss) available for common stock [(a)] [(b)]	$43,197	$30,518	$23,124	$18,123
Income (loss) per share for continuing operations - Basic	$0.98	$0.69	$0.52	$0.43
Income (loss) per share for discontinued operations - Basic	—	—	—	(0.02)
Income (loss) per share - Basic	$0.98	$0.69	$0.52	$0.41
Income (loss) per share for continuing operations - Diluted	$0.97	$0.69	$0.52	$0.43
Income (loss) per share for discontinued operations - Diluted	—	—	—	(0.02)
Income (loss) per share - Diluted	$0.97	$0.69	$0.52	$0.41
Dividends paid per share	$0.380	$0.380	$0.380	$0.380
Common stock prices - High	$44.32	$50.53	$55.09	$54.83
Common stock prices - Low	$36.89	$43.19	$46.62	$47.00

(a) Includes unrealized mark-to-market gain (loss) for interest rate swaps of $4.8 million, $12 million, $2.0 million and $0.5 million after-tax in the first, second, third and fourth quarters, respectively.

(b) Fourth quarter 2013 includes $7.6 million after-tax for a make-whole premium and write-off of deferred financing costs relating to the early redemption of our $250 million notes and interest expense on new debt and a $6.6 million after-tax expense relating to the settlement of interest rate swaps in conjunction with the prepayment of Black Hills Wyoming's project financing and write-off of deferred financing costs.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 (Exchange Act)) as of December 31, 2014. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

Internal Control over Financial Reporting

Management's Report on Internal Control over Financial Reporting is presented on Page 117 of this Annual Report on Form 10-K.

During our fourth quarter, there have been no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information required under this item with respect to directors and information required by Items 401, 405, 406, 407(c)(3), 407(d)(4) and 407(d)(5) of Regulation S-K, is set forth in the Proxy Statement for our 2015 Annual Meeting of Shareholders, which is incorporated herein by reference.

Executive Officers

David R. Emery, age 52, has been Chairman, President and Chief Executive Officer since April 2005. Prior to that, he held various positions with the company, including President and Chief Executive Officer and member of the Board of Directors from January 2004 to April 2005, President and Chief Operating Officer — Retail Business Segment from April 2003 to January 2004 and Vice President — Fuel Resources from January 1997 to April 2003. Mr. Emery has 25 years of experience with the Company.

Scott A. Buchholz, age 53, has been our Senior Vice President — Chief Information Officer since the closing of the Aquila Transaction in July 2008. Prior to joining the Company, he was Aquila's Vice President of Information Technology from June 2005 until July 2008, Six Sigma Deployment Leader/Black Belt from January 2004 until June 2005, and General Manager, Corporate Information Technology from February 2002 until January 2004. He was employed with Aquila for 28 years.

Anthony S. Cleberg, age 62, has been Executive Vice President since January 1, 2015. Mr. Cleberg served as the Executive Vice President and Chief Financial Officer from July 2008 to December 2014. He was an independent investor, developer and consultant with companies in Colorado and Wyoming from 2002 until joining the Company in 2008. Prior to his consulting role, he was the Executive Vice President and Chief Financial Officer of two publicly-traded companies: Washington Group, International, Inc., a large engineering and construction company involved in power plant construction and mining operations, and Champion Enterprises, a builder of factory-built housing. Before his CFO roles, he spent 15 years in various senior financial positions with Honeywell International, Inc., and eight years in public accounting at Deloitte & Touche LLP. Mr. Cleberg plans to retire in March 2015.

Richard W. Kinzley, age 49, has been Senior Vice President and Chief Financial Officer since January 1, 2015. He served as Vice President - Corporate Controller from March 2013 to December 2014, Vice President - Strategic Planning and Development from September 2008 to March 2013, and as Director of Corporate Development from April 2000 to September 2008. Mr. Kinzley has 15 years of experience with the Company.

Linden R. Evans, age 52, has been President and Chief Operating Officer — Utilities since October 2004. Mr. Evans served as the Vice President and General Manager of our former communication subsidiary from December 2003 to October 2004, and served as our Associate Counsel from May 2001 to December 2003. Mr. Evans has 13 years of experience with the Company.

Steven J. Helmers, age 58, has been our Senior Vice President, General Counsel and Chief Compliance Officer since January 2008. He served as our Senior Vice President, General Counsel since January 2004 and our Senior Vice President, General Counsel and Corporate Secretary from 2001 to 2004. Mr. Helmers has 14 years of experience with the Company.

Brian G. Iverson, age 52, has been Senior Vice President - Regulatory and Governmental Affairs and Assistant General Counsel since November 2014. He served as Vice President and Treasurer from March 2011 to November

2014, Vice President - Electric Regulatory Services from July 2008 to March 2011 and as Corporate Counsel from February 2004 to July 2008. Mr. Iverson has 11 years of experience with the Company.

Robert A. Myers, age 57, has been our Senior Vice President — Chief Human Resource Officer since January 2009 and served as our Interim Human Resources Executive since June 2008. He was a partner with Strategic Talent Solutions, a human resources consulting firm, from October 2006 until December 2008, Senior Vice President — Chief Human Resource Officer for Devon Energy from March 2006 until September 2006, and Senior Vice President and Chief Human Resource Officer at Reebok International, Ltd from November 2003 until January 2006. He has over 33 years of service in key human resources leadership roles.

ITEM 11. EXECUTIVE COMPENSATION

Information required under this item is set forth in the Proxy Statement for our 2015 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information regarding the security ownership of certain beneficial owners and management is set forth in the Proxy Statement for our 2015 Annual Meeting of Shareholders, which is incorporated herein by reference.

EQUITY COMPENSATION PLAN INFORMATION

The following table includes information as of December 31, 2014 with respect to our equity compensation plan, which is the 2005 Omnibus Incentive Plan.

Equity Compensation Plan Information

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights		Weighted-average exercise price of outstanding options, warrants and rights		Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))	
	(a)		(b)		(c)	
Equity compensation plans approved by security holders	351,941	(1)	$46.12	(1)	522,831	(2)
Equity compensation plans not approved by security holders	—		$—		—	
Total	351,941		$46.12		522,831	

(1) Includes 218,192 full value awards outstanding as of December 31, 2014, comprised of restricted stock units, performance shares and Director common stock units. The weighted average exercise price does not include the restricted stock units, performance shares or common stock units. In addition, 233,692 shares of unvested restricted stock were outstanding as of December 31, 2014, which are not included in the above table because they have already been issued.

(2) Shares available for issuance are from the 2005 Omnibus Incentive Plan. The 2005 Omnibus Incentive Plan permits the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards and other stock based awards.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information regarding certain relationships and related transactions and director independence is set forth in the Proxy Statement for our 2015 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information regarding principal accounting fees and services is set forth in the Proxy Statement for our 2015 Annual Meeting to Shareholders, which is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) 1. Consolidated Financial Statements

Financial statements required under this item are included in Item 8 of Part II

2. Schedules

Schedule II — Consolidated Valuation and Qualifying Accounts for the years ended December 31, 2014, 2013 and 2012

All other schedules have been omitted because of the absence of the conditions under which they are required or because the required information is included in our consolidated financial statements and notes thereto.

3. Exhibits

SCHEDULE II
BLACK HILLS CORPORATION
CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DECEMBER 31, 2014, 2013 AND 2012

Description	Balance at Beginning of Year	Adjustments	Additions Charged to Costs and Expenses	Recoveries and Other Additions	Write-offs and Other Deductions	Balance at End of Year
	(in thousands)					
Allowance for doubtful accounts:						
2014	$1,237	$—	$4,470	$4,233	$(8,424)	$1,516
2013	$768	$—	$2,780	$4,999	$(7,310)	$1,237
2012	$1,661	$—	$1,913	$3,822	$(6,628)	$768

3. Exhibits

Exhibit Number	Description
3.1*	Restated Articles of Incorporation of the Registrant (filed as Exhibit 3 to the Registrant's Form 10-K for 2004).
3.2*	Amended and Restated Bylaws of the Registrant dated January 28, 2010 (filed as Exhibit 3 to the Registrant's Form 8-K filed on February 3, 2010).
4.1*	Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to LaSalle Bank National Association), as Trustee (filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant's Form 8-K filed on May 14, 2009). Third Supplemental Indenture dated as of July 16, 2010 (filed as Exhibit 4 to Registrant's Form 8-K filed on July 15, 2010). Fourth Supplemental Indenture dated as of November 19, 2013 (filed as Exhibit 4 to the Registrant's Form 8-K filed on November 18, 2013).
4.2*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S 3 (No. 333 150669)). Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant's Post-Effective Amendment No. 2 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). Third Supplemental Indenture, dated as of October 1, 2014, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on October 2, 2014).
4.3*	Restated Indenture of Mortgage, Deed of Trust, Security Agreement and Financing Statement, amended and restated as of November 20, 2007, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on October 2, 2014). First Supplemental Indenture, dated as of September 3, 2009, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on October 2, 2014). Second Supplemental Indenture, dated as of October 1, 2014, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.4 to the Registrant's Form 8-K filed on October 2, 2014).
4.4*	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000).
10.1*†	Amended and Restated Pension Equalization Plan of Black Hills Corporation dated November 6, 2001 (filed as Exhibit 10.11 to the Registrant's Form 10-K/A for 2001). First Amendment to Pension Equalization Plan (filed as Exhibit 10.10 to the Registrant's Form 10-K for 2002). Grandfather Amendment to the Amended and Restated Pension Equalization Plan of Black Hills Corporation (filed

	as Exhibit 10.2 to the Registrant's Form 10-K for 2008).
10.2*†	2005 Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.3 to the Registrant's Form 10-K for 2008).
10.3*†	Restoration Plan of Black Hills Corporation (filed as Exhibit 10.5 to the Registrant's Form 10-K for 2008). First Amendment to the Restoration Plan of Black Hills Corporation dated July 24, 2011 (filed as Exhibit 10.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2011).

10.4*†	Black Hills Corporation Non-qualified Deferred Compensation Plan as Amended and Restated effective January 1, 2011 (filed as Exhibit 10.4 to the Registrant's Form 10-K for 2010).
10.5*†	Black Hills Corporation 2005 Omnibus Incentive Plan ("Omnibus Plan") (filed as Appendix A to the Registrant's Proxy Statement filed April 13, 2005). First Amendment to the Omnibus Plan (filed as Exhibit 10.11 to the Registrant's Form 10-K for 2008). Second Amendment to the Omnibus Plan (filed as Exhibit 10 to the Registrant's Form 8-K filed on May 26, 2010).
10.6*†	Form of Stock Option Agreement for Omnibus Plan effective for awards granted on or after January 1, 2009 (filed as Exhibit 10.13 to the Registrant's Form 10-K for 2008). Form of Stock Option Agreement for Omnibus Plan effective for awards granted on or after January 1, 2014 (filed as Exhibit 10.7 to the Registrant's Form 10-K for 2013).
10.7*†	Form of Restricted Stock Award Agreement for Omnibus Plan effective for awards granted on or after January 1, 2009 (filed as Exhibit 10.15 to the Registrant's Form 10-K for 2008). Form of Restricted Stock Award for Omnibus Plan effective for awards granted on or after January 1, 2014 (filed as Exhibit 10.9 to the Registrant's Form 10-K for 2013).
10.8*†	Form of Restricted Stock Unit Award Agreement for Omnibus Plan effective for awards granted on or after January 1, 2014 (filed as Exhibit 10.10 to the Registrant's Form 10-K for 2013).
10.9*†	Form of Performance Share Award Agreement for Omnibus Plan effective for awards granted on or after January 1, 2012 (filed as Exhibit 10.10 to Registrant's Form 10-K for 2011). Form of Performance Share Award Agreement for Omnibus Plan effective for awards granted on or after January 1, 2014 (filed as Exhibit 10.12 to the Registrant's Form 10-K for 2013).
10.10†	Form of Performance Share Award Agreement for Omnibus Plan effective for awards granted on or after January 1, 2015.
10.11*†	Form of Short-term Incentive for Omnibus Plan effective for awards granted on or after January 1, 2010 (filed as Exhibit 10.1 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2010).
10.12*†	Form of Indemnification Agreement (filed as Exhibit 10.5 to the Registrant's Form 8-K filed on September 3, 2004).
10.13*†	Change in Control Agreement dated November 15, 2013 between Black Hills Corporation and David R. Emery (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on November 19, 2013).
10.14*†	Form of Change in Control Agreements between Black Hills Corporation and its non-CEO Senior Executive Officers (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on November 19, 2013).
10.15*†	Outside Directors Stock Based Compensation Plan as Amended and Restated effective January 1, 2009 (filed as Exhibit 10.23 to the Registrant's Form 10-K for 2008). First Amendment to the Outside Directors Stock Based Compensation Plan effective January 1, 2011 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2010). Second Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2013 (filed as Exhibit 10.15 to the Registrant's Form 10-K for 2012).

10.16†	Third Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2015.
10.17*†	Form of Non-Disclosure and Non-Solicitation Agreement for Certain Employees (filed as Exhibit 10.19 to the Registrant's Form 10-K for 2011).
10.18*	Bond Purchase Agreement dated as of June 30, 2014 by and among Black Hills Power, Inc., New York Life Insurance Company, New York Life Insurance and Annuity Corporation, Teachers Insurance and Annuity Association of America, John Hancock Life Insurance Company (U.S.A.), John Hancock Life & Health Insurance Company, John Hancock Life Insurance Company of New York and United of Omaha Life Insurance Company (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on July 2, 2014).

10.19*	Bond Purchase Agreement dated as of June 30, 2014 by and among Cheyenne Light Fuel and Power Company, New York Life Insurance Company, New York Life Insurance and Annuity Corporation, Teachers Insurance and Annuity Association of America, John Hancock Life Insurance Company (U.S.A.), John Hancock Life & Health Insurance Company, John Hancock Life Insurance Company of New York, Mutual of Omaha Insurance Company, United of Omaha Life Insurance Company and American Equity Investment Life Insurance Company (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on July 2, 2014).
10.20*	Credit Agreement, dated June 21, 2013 among Black Hills Corporation, as Borrower, J.P. Morgan Chase Bank, N.A., in its capacity as administrative agent for the Banks under the Credit Agreement, and as a Bank, and the other Banks party thereto (filed as Exhibit 10 to the Registrant's Form 8-K filed on June 24, 2013).
10.21*	Credit Agreement, dated May 29, 2014, among Black Hills Corporation, as Borrower, U.S. Bank, National Association, in its capacity as administrative agent for the Banks under the Credit Agreement, and as a Bank, and the other banks party thereto (filed as Exhibit 10 to the Registrant's Form 8-K filed on May 30, 2014).
10.22*	Coal Leases between WRDC and the Federal Government -Dated May 1, 1959 (filed as Exhibit 5(i) to the Registrant's Form S 7, File No. 2 60755) -Modified January 22, 1990 (filed as Exhibit 10(h) to the Registrant's Form 10 K for 1989) -Dated April 1, 1961 (filed as Exhibit 5(j) to the Registrant's Form S 7, File No. 2 60755) -Modified January 22, 1990 (filed as Exhibit 10(i) to Registrant's Form 10 K for 1989) -Dated October 1, 1965 (filed as Exhibit 5(k) to the Registrant's Form S 7, File No. 2 60755) -Modified January 22, 1990 (filed as Exhibit 10(j) to the Registrant's Form 10 K for 1989).
10.23*	Assignment of Mining Leases and Related Agreement effective May 27, 1997, between WRDC and Kerr-McGee Coal Corporation (filed as Exhibit 10(u) to the Registrant's Form 10-K for 1997).
21	List of Subsidiaries of Black Hills Corporation.
23.1	Consent of Independent Registered Public Accounting Firm.
23.2	Consent of Petroleum Engineer and Geologist.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	Mine Safety and Health Administration Safety Data

99	Report of Cawley, Gillespie & Associates, Inc.
101	Financial Statements in XBRL Format

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* Previously filed as part of the filing indicated and incorporated by reference herein.
† Indicates a board of director or management compensatory plan.
(a) See (a) 3. Exhibits above.
(b) See (a) 2. Schedules above.

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.

BLACK HILLS CORPORATION

By: /S/ DAVID R. EMERY
David R. Emery, Chairman, President
and Chief Executive Officer

Dated: February 24, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/S/ DAVID R. EMERY David R. Emery, Chairman, President and Chief Executive Officer	Director and Principal Executive Officer	February 24, 2015
/S/ RICHARD W. KINZLEY Richard W. Kinzley, Senior Vice President and Chief Financial Officer	Principal Financial and Accounting Officer	February 24, 2015
/S/ JACK W. EUGSTER Jack W. Eugster	Director	February 24, 2015
/S/ MICHAEL H. MADISON Michael H. Madison	Director	February 24, 2015
/S/ LINDA K. MASSMAN Linda K. Massman	Director	February 24, 2015
/S/ STEVEN R. MILLS Steven R. Mills	Director	February 24, 2015
/S/ STEPHEN D. NEWLIN Stephen D. Newlin	Director	February 24, 2015
/S/ GARY L. PECHOTA Gary L. Pechota	Director	February 24, 2015
/S/ REBECCA B. ROBERTS Rebecca B. Roberts	Director	February 24, 2015
/S/ WARREN L. ROBINSON Warren L. Robinson	Director	February 24, 2015
/S/ JOHN B. VERING John B. Vering	Director	February 24, 2015

/S/ THOMAS J. ZELLER Thomas J. Zeller	Director	February 24, 2015

INDEX TO EXHIBITS

Exhibit Number	Description
3.1*	Restated Articles of Incorporation of the Registrant (filed as Exhibit 3 to the Registrant's Form 10-K for 2004).
3.2*	Amended and Restated Bylaws of the Registrant dated January 28, 2010 (filed as Exhibit 3 to the Registrant's Form 8-K filed on February 3, 2010).
4.1*	Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to LaSalle Bank National Association), as Trustee (filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant's Form 8-K filed on May 14, 2009). Third Supplemental Indenture dated as of July 16, 2010 (filed as Exhibit 4 to the Registrant's Form 8-K filed on July 15, 2010). Fourth Supplemental Indenture dated as of November 19, 2013 (filed as Exhibit 4 to the Registrants' Form 8-K filed on November 18, 2013).
4.2*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S 3 (No. 333 150669)). Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant's Post-Effective Amendment No. 2 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). Third Supplemental Indenture, dated as of October 1, 2014, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on October 2, 2014).
4.3*	Restated Indenture of Mortgage, Deed of Trust, Security Agreement and Financing Statement, amended and restated as of November 20, 2007, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on October 2, 2014). First Supplemental Indenture, dated as of September 3, 2009, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on October 2, 2014). Second Supplemental Indenture, dated as of October 1, 2014, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.4 to the Registrant's Form 8-K filed on October 2, 2014).
4.4*	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000).
10.1*†	Amended and Restated Pension Equalization Plan of Black Hills Corporation dated November 6, 2001 (filed as Exhibit 10.11 to the Registrant's Form 10-K/A for 2001). First Amendment to Pension Equalization Plan (filed as Exhibit 10.10 to the Registrant's Form 10-K for 2002). Grandfather Amendment to the Amended and Restated Pension Equalization Plan of Black Hills Corporation (filed

	as Exhibit 10.2 to the Registrant's Form 10-K for 2008).
10.2*†	2005 Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.3 to the Registrant's Form 10-K for 2008).
10.3*†	Restoration Plan of Black Hills Corporation (filed as Exhibit 10.5 to the Registrant's Form 10-K for 2008). First Amendment to the Restoration Plan of Black Hills Corporation dated July 24, 2011 (filed as Exhibit 10.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2011).
10.4*†	Black Hills Corporation Non-qualified Deferred Compensation Plan as Amended and Restated effective January 1, 2011 (filed as Exhibit 10.4 to the Registrant's Form 10-K for 2010).

10.5*†	Black Hills Corporation 2005 Omnibus Incentive Plan (”Omnibus Plan”) (filed as Appendix A to the Registrant’s Proxy Statement filed April 13, 2005). First Amendment to the Omnibus Plan (filed as Exhibit 10.11 to the Registrant’s Form 10-K for 2008). Second Amendment to the Omnibus Plan (filed as Exhibit 10 to the Registrant’s Form 8-K filed on May 26, 2010).
10.6*†	Form of Stock Option Agreement for Omnibus Plan effective for awards granted on or after January 1, 2009 (filed as Exhibit 10.13 to the Registrant’s Form 10-K for 2008). Form of Stock Option Agreement for Omnibus Plan effective for awards granted on or after January 1, 2014 (filed as Exhibit 10.7 to the Registrant’s Form 10-K for 2013.
10.7*†	Form of Restricted Stock Award Agreement for Omnibus Plan effective for awards granted on or after January 1, 2009 (filed as Exhibit 10.15 to the Registrant’s Form 10-K for 2008). Form of Restricted Stock Award for Omnibus Plan effective for awards granted on or after January 1, 2014 (filed as Exhibit 10.9 to the Registrant’s Form 10-K for 2013).
10.8*†	Form of Restricted Stock Unit Award Agreement for Omnibus Plan effective for awards granted on or after January 1, 2014 (filed as Exhibit 10.10 to the Registrant’s Form 10-K for 2013).
10.9*†	Form of Performance Share Award Agreement for Omnibus Plan effective for awards granted on or after January 1, 2012 (filed as Exhibit 10.10 to the Registrant’s Form 10-K for 2011). Form of Performance Share Award Agreement for Omnibus Plan effective for awards granted on or after January 1, 2014 (filed as Exhibit 10.12 to the Registrant’s Form 10-K for 2013).
10.10†	Form of Performance Share Award Agreement for Omnibus Plan effective for awards granted on or after January 1, 2015.
10.11*†	Form of Short-Term Incentive for Omnibus Plan effective for awards granted on or after January 1, 2010 (filed as Exhibit 10.1 to the Registrant’s Form 10-Q for the quarterly period ended March 31, 2010).
10.12*†	Form of Indemnification Agreement (filed as Exhibit 10.5 to the Registrant’s Form 8-K filed on September 3, 2004).
10.13*†	Change in Control Agreement dated November 15, 2013 between Black Hills Corporation and David R. Emery (filed as Exhibit 10.1 to the Registrant’s Form 8-K filed on November 19, 2013).
10.14*†	Form of Change in Control Agreements between Black Hills Corporation and its non-CEO Senior Executive Officers (filed as Exhibit 10.2 to the Registrant’s Form 8-K filed on November 19, 2013).
10.15*†	Outside Directors Stock Based Compensation Plan as Amended and Restated effective January 1, 2009 (filed as Exhibit 10.23 to the Registrant’s Form 10-K for 2008). First Amendment to the Outside Directors Stock Based Compensation Plan effective January 1, 2011 (filed as Exhibit 10.16 to the Registrant’s Form 10-K for 2010). Second Amendment to the Outside Director’s Stock Based Compensation Plan effective January 1, 2013 (filed as Exhibit 10.15 to the Registrant’s Form 10-K for 2012).
10.16†	Third Amendment to the Outside Director’s Stock Based Compensation Plan effective January 1, 2015.
10.17*†	

	Form of Non-Disclosure and Non-Solicitation Agreement for Certain Employees (filed as Exhibit 10.19 to the Registrant's Form 10-K for 2011).
10.18*	Bond Purchase Agreement dated as of June 30, 2014 by and among Black Hills Power, Inc., New York Life Insurance Company, New York Life Insurance and Annuity Corporation, Teachers Insurance and Annuity Association of America, John Hancock Life Insurance Company (U.S.A.), John Hancock Life & Health Insurance Company, John Hancock Life Insurance Company of New York and United of Omaha Life Insurance Company (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on July 2, 2014).
10.19*	Bond Purchase Agreement dated as of June 30, 2014 by and among Cheyenne Light Fuel and Power Company, New York Life Insurance Company, New York Life Insurance and Annuity Corporation, Teachers Insurance and Annuity Association of America, John Hancock Life Insurance Company (U.S.A.), John Hancock Life & Health Insurance Company, John Hancock Life Insurance Company of New York, Mutual of Omaha Insurance Company, United of Omaha Life Insurance Company and American Equity Investment Life Insurance Company (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on July 2, 2014).

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10.20*	Credit Agreement dated June 21, 2013 among Black Hills Corporation, as borrower, J.P. Morgan Chase Bank, N.A., in its capacity as administrative agent for the Banks under the Credit Agreement, and as a Bank, and the other Banks party thereto (filed as Exhibit 10 to the Registrant's Form 8-K filed on June 24, 2013).
10.21*	Credit Agreement, dated May 29, 2014, among Black Hills Corporation, as Borrower, U.S. Bank, National Association, in its capacity as administrative agent for the Banks under the Credit Agreement, and as a Bank, and the other banks party thereto (filed as Exhibit 10 to the Registrant's Form 8-K filed on May 30, 2014).
10.22*	Coal Leases between WRDC and the Federal Government -Dated May 1, 1959 (filed as Exhibit 5(i) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(h) to the Registrant's Form 10-K for 1989) -Dated April 1, 1961 (filed as Exhibit 5(j) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(i) to Registrant's Form 10-K for 1989) -Dated October 1, 1965 (filed as Exhibit 5(k) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(j) to the Registrant's Form 10-K for 1989).
10.23*	Assignment of Mining Leases and Related Agreement effective May 27, 1997, between WRDC and Kerr-McGee Coal Corporation (filed as Exhibit 10(u) to the Registrant's Form 10-K for 1997).
21	List of Subsidiaries of Black Hills Corporation.
23.1	Consent of Independent Registered Public Accounting Firm.
23.2	Consent of Petroleum Engineer and Geologist.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	Mine Safety and Health Administration Safety Data
99	Report of Cawley, Gillespie & Associates, Inc.
101	Financial Statements in XBRL Format

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*Previously filed as part of the filing indicated and incorporated by reference herein.
†Indicates a board of director or management compensatory plan.