BLACK HILLS CORP /SD/
Form 10-K
February 27, 2017

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, 2016
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. o

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, 2016 $3,248,873,889

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, 2017
Common stock, $1.00 par value	53,384,259 shares

Documents Incorporated by Reference

Portions of the Registrant's Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2017 Annual Meeting of Stockholders to be held on April 25, 2017, 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
APSC	Arkansas Public Service Commission
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
ATM	At-the-market equity offering program
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
Bcf	Billion cubic feet
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.
Black Hills Colorado IPP	Black Hills Colorado IPP, LLC a 50.1% owned subsidiary of Black Hills Electric Generation
Black Hills Gas	Black Hills Gas, LLC, a subsidiary of Black Hills Gas Holdings, which was previously named SourceGas LLC.
Black Hills Gas Holdings	Black Hills Gas Holdings, LLC, a subsidiary of Black Hills Utility Holdings, which was previously named SourceGas Holdings LLC
Black Hills Electric Generation	Black Hills Electric Generation, LLC, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Energy	The name used to conduct the business of our utility companies
Black Hills Energy Arkansas Gas	Includes the acquired SourceGas utility Black Hills Energy Arkansas, Inc. utility operations
Black Hills Energy Colorado Electric	Includes Colorado Electric's utility operations
Black Hills Energy Colorado Gas	Includes Black Hills Energy Colorado Gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution's Colorado gas operations and RMNG
Black Hills Energy Iowa Gas	Includes Black Hills Energy Iowa gas utility operations
Black Hills Energy Kansas Gas	Includes Black Hills Energy Kansas gas utility operations
Black Hills Energy Nebraska Gas	Includes Black Hills Energy Nebraska gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution's Nebraska gas operations
Black Hills Energy Services	A Choice Gas supplier acquired in the SourceGas Acquisition
Black Hills Energy South Dakota Electric	Includes Black Hills Power's operations in South Dakota, Wyoming and Montana

Black Hills Energy Wyoming Electric	Includes Cheyenne Light's electric utility operations
Black Hills Energy Wyoming Gas	Includes Cheyenne Light's natural gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution's Wyoming gas operations
Black Hills Gas Distribution	Black Hills Gas Distribution, LLC, a company acquired in the SourceGas Acquisition that conducts the gas distribution operations in Colorado, Nebraska and Wyoming. It was formerly named SourceGas Distribution LLC.
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 (doing business as Black Hills Energy)
BHSC	Black Hills Service Company LLC, 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 (doing business as Black Hills Energy)
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
Busch Ranch	Busch Ranch Wind Farm is a 29 MW wind farm near Pueblo, Colorado, jointly owned by Colorado Electric and AltaGas. Colorado Electric has a 50% ownership interest in the wind farm.
Ceiling Test	Related to our Oil and Gas subsidiary, 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.
CAPP	Customer Appliance Protection Plan - acquired in the SourceGas Acquisition
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 (doing business as Black Hills Energy)
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.
Choice Gas Program	The unbundling of the natural gas service from the distribution component, which opens up the gas supply for competition allowing customers to choose from different natural gas suppliers. Black Hills Gas Distribution distributes the gas and Black Hills Energy Service is one of the Choice Gas suppliers.
City of Gillette	Gillette, Wyoming
CO_2	Carbon dioxide
Colorado Electric	Black Hills Colorado Electric Utility Company, LP, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
Colorado Gas	Black Hills Colorado Gas Utility Company, LP, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
Colorado Interstate Gas (CIG)	Colorado Interstate Natural Gas Pricing Index
Colorado IPP	Black Hills Colorado IPP, LLC a 50.1% owned subsidiary of Black Hills Electric Generation
Consolidated Indebtedness to Capitalization Ratio	Any Indebtedness outstanding at such time, divided by Capital at such time. Capital being Consolidated Net-Worth (excluding noncontrolling interest and including the aggregate outstanding amount of RSNs) plus Consolidated Indebtedness (including letters of credit, certain guarantees issued and excluding RSNs) as defined within the current Credit Agreement.
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.
Cost of Service Gas Program (COSG)	Proposed Cost of Service Gas Program designed to provide long-term natural gas price stability for the Company's utility customers, along with a reasonable expectation of customer savings

	over the life of the program.
CPCN	Certificate of Public Convenience and Necessity
CPP	Clean Power Plan
CP Program	Commercial Paper Program
CPUC	Colorado Public Utilities Commission
CT	Combustion turbine
CTII	The 40 MW Gillette CT, a simple-cycle, gas-fired combustion turbine owned by the City of Gillette.

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
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DSM	Demand Side Management
DRSPP	Dividend Reinvestment and Stock Purchase Plan
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)
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
Energy West	Energy West Wyoming, Inc., a subsidiary of Gas Natural, Inc. Energy West is an acquisition we closed on July 1, 2015.
Enserco	Enserco Energy Inc., a former wholly-owned subsidiary of Black Hills Non-regulated Holdings, which is presented in discontinued operations in 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
Equity Unit	Each Equity Unit has a stated amount of $50, consisting of a purchase contract issued by BHC to purchase shares of BHC common stock and a 1/20, or 5% undivided beneficial ownership interest in $1,000 principal amount of BHC RSNs due 2028.
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
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
Iowa Gas	Black Hills Iowa Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
IPP	Independent power producer
IPP Transaction	The July 11, 2008 sale of seven of our IPP plants
IRS	United States Internal Revenue Service

KCC	Kansas Corporation Commission
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
kV	Kilovolt

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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
Mcfd	Thousand cubic feet per day
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 Plant
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
NAV	Net Asset Value
Nebraska Gas	Black Hills Nebraska Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
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
NPDES	National Pollutant Discharge Elimination System
NPSC	Nebraska Public Service Commission
NWPL	Northwest Interstate Natural Gas Pricing Index
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OSHA	Occupational Safety & Health Administration
OSM	U.S. Department of the Interior's Office of Surface Mining
OTC	Over-the-counter
PCA	Power Cost Adjustment

PCCA	Power Capacity Cost Adjustment
Peak View	$109 million 60 MW wind generating project owned by Colorado Electric, placed in service on November 7, 2016 and adjacent to Busch Ranch Wind Farm
PPA	Power Purchase Agreement

PPACA	Patient Protection and Affordable Care Act of 2010
PPB	Parts per billion
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 $750 million credit facility used to fund working capital needs, letters of credit and other corporate purposes, which matures in 2021
RMNG	Rocky Mountain Natural Gas, a regulated gas utility acquired in the SourceGas Acquisition that provides regulated transmission and wholesale natural gas service to Black Hills Gas Distribution in western Colorado (doing business as Black Hills Energy)
RSNs	Remarketable junior subordinated notes, issued on November 23, 2015
SAIDI	System Average Interruption Duration Index
SDPUC	South Dakota Public Utilities Commission
SEC	U. S. Securities and Exchange Commission
Service Guard	Home appliance repair product offering for both natural gas and electric.
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.
SourceGas	SourceGas Holdings LLC and its subsidiaries, a gas utility owned by funds managed by Alinda Capital Partners and GE Energy Financial Services, a unit of General Electric Co. (NYSE:GE) that was acquired on February 12, 2016, and is now named Black Hills Gas Holdings, LLC (doing business as Black Hills Energy)
SourceGas Acquisition	The acquisition of SourceGas Holdings, LLC by Black Hills Utility Holdings
SourceGas Transaction	On February 12, 2016, Black Hills Utility Holdings acquired SourceGas pursuant to a purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, which included the assumption of $760 million in debt at closing.
Spinning Reserve	Generation capacity that is on-line but unloaded and that can respond within 10 minutes to compensate for generation or transmission outages
SSIR	System Safety and Integrity Rider
SSTAR-TEXOK	Natural gas price index tied to the Southern Star Central gas pipeline
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)
VEBA	Voluntary Employee Benefit Association
VIE	Variable Interest Entity
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 oil, an oil index benchmark price as quoted by NYMEX
Wyodak Plant	Wyodak, a 362 MW mine-mouth coal-fired plant in Gillette, Wyoming, owned 80% by PacifiCorp and 20% by Black Hills Energy South Dakota. Our WRDC mine supplies all of the fuel for the plant.

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 customer-focused, growth-oriented, vertically-integrated utility 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, with the purchase of the Wyodak Coal Mine, we began producing, selling and marketing various forms of energy through non-regulated businesses.

We operate our business in the United States, reporting our operating results through our regulated Electric Utilities segment, regulated Gas Utilities segment, Power Generation segment, Mining Segment and Oil and Gas Segment.

Our Electric Utilities segment generates, transmits and distributes electricity to approximately 208,500 electric customers in South Dakota, Wyoming, Colorado and Montana. Our Electric Utilities own 941 MW of generation and 8,806 miles of electric transmission and distribution lines.

Our Gas Utilities segment serves approximately 1,030,800 natural gas utility customers in Arkansas, Colorado, Iowa, Nebraska, Kansas and Wyoming. Our Gas Utilities own 4,585 miles of intrastate gas transmission pipelines and 40,044 miles of gas distribution mains and service lines. On February 12, 2016, we acquired SourceGas Holdings, LLC, adding four regulated natural gas utilities serving approximately 431,000 customers in Arkansas, Colorado, Nebraska and Wyoming and a 512 mile regulated intrastate natural gas transmission pipeline in Colorado. For additional information on this acquisition, see the Key Elements of our Business Strategy in Item 7 and Note 2 in the Notes to Consolidated Financial Statements in Item 8.

Our Power Generation segment produces electric power from its generating plants and sells the electric capacity and energy primarily to our utilities under long-term contracts. Our Mining segment produces coal at our 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, with a focus on divesting non-core oil and gas assets and retaining those best suited to assist utilities with the implementation of cost of service gas programs. For additional information, see the Key Elements of our Business Strategy in Item 7.

Our segments generated the following net income (loss) available for common stock for the year ended December 31, 2016 and had the following total assets at December 31, 2016 (excluding Corporate):

	Net income (loss) available for common stock for the year ended December 31, 2016 (in thousands)	Total Assets as of December 31, 2016
Electric Utilities	$85,827	$2,859,559
Gas Utilities	$59,624	$3,307,967
Power Generation	$25,930	$73,445
Mining	$10,053	$67,347
Oil and Gas	($71,054)	$96,435

Segment reporting transition of Cheyenne Light's Natural Gas distribution

Effective January 1, 2016, the natural gas operations of Cheyenne Light are reported in our Gas Utilities Segment. Through December 31, 2015, Cheyenne Light's natural gas operations were included in our Electric Utilities Segment as these natural gas operations were consolidated within Cheyenne Light since its acquisition. This change is a result of our business segment reorganization to, among other things, integrate all regulated natural gas operations, including the SourceGas Acquisition, into our Gas Utilities Segment which is led by the Group Vice President, Natural Gas Utilities. Likewise, all regulated electric utility operations including Cheyenne Light's electric utility operations are reported in our Electric Utilities Segment, which is led by the Group Vice President, Electric Utilities. The prior periods have been reclassified to reflect this change in presentation between the Electric Utilities and Gas Utilities segments.

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 5 in the Notes to the Consolidated Financial Statements, in this Annual Report on Form 10-K.

Utility Rebranding

All of our utilities now operate with the trade name Black Hills Energy. We expanded our regulated operations with the acquisition of SourceGas, as well as with our 2015 utility acquisitions. We rebranded our Cheyenne Light utilities, Black Hills Power utility and our SourceGas utilities to operate under the name Black Hills Energy, conforming to the name under which our other utilities operate. Within our Electric Utilities segment and our Gas Utilities segment, references made to our utilities are presented as follows according to their respective state:

Electric Utilities Segment

- Black Hills Energy South Dakota Electric - includes all Black Hills Power utility operations in South Dakota, Wyoming and Montana.
- Black Hills Energy Wyoming Electric - includes all Cheyenne Light electric utility operations.
- Black Hills Energy Colorado Electric - includes all Colorado Electric utility operations.

Gas Utilities Segment

- Black Hills Energy Arkansas Gas - includes the acquired SourceGas utility Black Hills Energy Arkansas operations.
- Black Hills Energy Colorado Gas - includes Black Hills Energy Colorado Gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution's Colorado operations and RMNG operations.
- Black Hills Energy Nebraska Gas - includes Black Hills Energy Nebraska gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution's Nebraska operations.
- Black Hills Energy Iowa Gas - includes Black Hills Energy Iowa gas utility operations.
- Black Hills Energy Kansas Gas - includes Black Hills Energy Kansas gas utility operations.
- Black Hills Energy Wyoming Gas - includes Cheyenne Light's natural gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution's Wyoming operations.
- Black Hills Energy Services - includes the acquired SourceGas Utility Black Hills Energy Services operations.

Electric Utilities Segment

We conduct electric utility operations through our South Dakota, Wyoming and Colorado subsidiaries. Our Electric Utilities generate, transmit and distribute electricity to approximately 208,500 customers in South Dakota, Wyoming, Colorado and Montana. 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 also provide non-regulated services through our Tech Services product lines. Tech Services provides electrical system construction services to large industrial customers of our electric utilities.

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)					
	2016		2015		2014	
	Summer	Winter	Summer	Winter	Summer	Winter
South Dakota Electric	438	389	424	369	410	389
Wyoming Electric (a)	236	230	212	202	198	197
Colorado Electric (b)	412	302	392	303	384	298
Total Electric Utilities Peak Demands	1,086	921	1,028	874	992	884

(a) Both 2016 summer and winter peaks are records set in July and December, respectively, replacing summer and winter record peaks set in July and December of 2015.

(b) New summer peak load for Colorado Electric achieved in July 2016, replacing the previous all-time summer peak of 406 set in June 2016, and of 400 set in June 2012.

Regulated Power Plants

As of December 31, 2016, our Electric Utilities' ownership interests in electric generation plants were as follows:

Unit	Fuel Type	Location	Ownership Interest %	Owned Capacity (MW)	Year Installed
South Dakota Electric:					
Cheyenne Prairie [(a)]	Gas	Cheyenne, Wyoming	58%	55.0	2014
Wygen III [(b)]	Coal	Gillette, Wyoming	52%	57.2	2010
Neil Simpson II	Coal	Gillette, Wyoming	100%	90.0	1995
Wyodak [(c)]	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
Wyoming Electric:					
Cheyenne Prairie [(a)]	Gas	Cheyenne, Wyoming	42%	40.0	2014
Cheyenne Prairie CT [(a)]	Gas	Cheyenne, Wyoming	100%	37.0	2014
Wygen II	Coal	Gillette, Wyoming	100%	95.0	2008
Colorado Electric:					
Busch Ranch Wind Farm [(d)]	Wind	Pueblo, Colorado	50%	14.5	2012
Peak View Wind Farm [(e)]	Wind	Pueblo, Colorado	100%	60.0	2016
Pueblo Airport Generation	Gas	Pueblo, Colorado	100%	180.0	2011
Pueblo Airport Generation CT [(f)]	Gas	Pueblo, Colorado	100%	40.0	2016
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				941.1	

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

(b) Wygen III, a 110 MW mine-mouth coal-fired power plant, is operated by South Dakota Electric. South Dakota Electric 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.

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

(d) 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.

(e) Peak View Wind Farm achieved commercial operation on November 7, 2016.

(f) Colorado Electric's newly constructed LM 6000, which achieved commercial operation on December 29, 2016.

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 MWh)	2016	2015	2014
Coal	$11.27	$10.89	$10.92
Natural Gas [(a)]	$30.59	$51.14	$77.31
Diesel Oil [(b)]	$149.13	$303.16	$174.04
Total Average Fuel Cost	$12.99	$14.62	$14.82
Purchased Power - Coal, Gas and Oil	$48.36	$47.81	$35.21
Purchased Power - Renewable Sources	$51.95	$50.92	$50.27

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(a) Decrease is driven by lower 2016 natural gas costs than the prior year.

(b) Decrease is due to combination of lower fuel costs in 2016 and the efficiencies at which the diesel units performed compared to the prior year.

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	2016	2015	2014
Coal	33 %	33 %	34 %
Gas, Oil and Wind	7	4	4
Total Generated	40	37	38
Purchased [(a)]	60	63	62
Total	100%	100%	100%

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(a) Wind represents approximately 7% of our purchased power in 2016, and approximately 5% of our purchased power in 2015 and 2014.

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:

- South Dakota Electric'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 reported and accounted for as a capital lease within our business segments and is eliminated on the accompanying Consolidated Financial Statements;

- 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 Farm;

- Wyoming Electric'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 Wyoming Electric to purchase Black Hills Wyoming's ownership interest in the Wygen I facility through 2019, subject to WPSC and FERC approval in order to obtain regulatory treatment. 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);

- Wyoming Electric'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 Wyoming Electric. Under a separate inter-company agreement, Wyoming Electric sells 50% of the facility's output to South Dakota Electric;

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- Wyoming Electric'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 Wyoming Electric. Under a separate inter-company agreement, Wyoming Electric sells 20 MW of the facility's output to South Dakota Electric; and

- Wyoming Electric and South Dakota Electric's Generation Dispatch Agreement requires South Dakota Electric to purchase all of Wyoming Electric'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, South Dakota Electric will provide MDU with 25 MW from its other generation facilities or from system purchases with reimbursement of costs by MDU;

- South Dakota Electric has an agreement through December 31, 2023 to provide 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, South Dakota Electric 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, South Dakota Electric will also provide the City of Gillette its operating component of spinning reserves; and

- South Dakota Electric has an 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:

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

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, 2016, our Electric Utilities owned the electric transmission and distribution lines shown below:

Utility	State	Transmission (in Line Miles)	Distribution (in Line Miles)
South Dakota Electric	South Dakota, Wyoming	1,260	2,497
South Dakota Electric - Jointly Owned [(a)]	South Dakota, Wyoming	44	—
Wyoming Electric	South Dakota, Wyoming	44	1,279
Colorado Electric	Colorado	590	3,092

(a) South Dakota Electric 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. South Dakota Electric’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.

South Dakota Electric 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.

South Dakota Electric 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 Wyoming Electric's existing load, Wyoming Electric 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 -

South Dakota Electric, Wyoming Electric, 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.

South Dakota Electric and Wyoming Electric receive certain staffing and management services from BHSC for Cheyenne Prairie.

- Jointly Owned Facilities -

South Dakota Electric, the City of Gillette and MDU are parties to a shared joint ownership agreement, whereby South Dakota Electric 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	2016			2015			2014	
	Actual	Variance from Prior Year	Variance from 30-Year Average (b)	Actual	Variance from Prior Year	Variance from 30-Year Average (b)	Actual	Variance from 30-Year Average (b)
Heating Degree Days:								
South Dakota Electric	6,402	(2)%	(10)%	6,521	(12)%	(8)%	7,373	4%
Wyoming Electric	6,363	(1)%	(14)%	6,404	(10)%	(10)%	7,100	—%
Colorado Electric	4,658	(4)%	(16)%	4,846	(12)%	(12)%	5,534	—%
Combined (a)	5,595	(2)%	(13)%	5,729	(11)%	(10)%	6,473	2%
Cooling Degree Days:								

South Dakota Electric	646	12%	(4)%	577	20%	(14)%	481	(28)%
Wyoming Electric	460	13%	31%	407	21%	16%	336	(5)%
Colorado Electric	1,358	7%	42%	1,270	38%	32%	919	(4)%
Combined [(a)]	935	9%	26%	861	32%	16%	654	(12)%

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(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)	2016	2015	2014
Residential:			
South Dakota Electric	$72,084	$72,659	$69,712
Wyoming Electric	39,553	39,587	36,634
Colorado Electric	97,088	97,418	94,391
Total Residential	208,725	209,664	200,737
Commercial:			
South Dakota Electric	97,579	100,511	91,882
Wyoming Electric	64,042	64,207	59,758
Colorado Electric	97,147	93,821	90,909
Total Commercial	258,768	258,539	242,549
Industrial:			
South Dakota Electric	33,409	33,336	28,451
Wyoming Electric [(a)]	45,498	36,594	29,066
Colorado Electric	39,274	42,325	39,219
Total Industrial	118,181	112,255	96,736
Municipal:			
South Dakota Electric	3,705	3,626	3,409
Wyoming Electric	2,122	2,179	1,930
Colorado Electric	11,994	12,058	13,312
Total Municipal	17,821	17,863	18,651
Subtotal Retail Revenue - Electric	603,495	598,321	558,673
Contract Wholesale:			
Total Contract Wholesale - South Dakota Electric	17,037	17,537	21,206
Off-system/Power Marketing Wholesale:			
South Dakota Electric [(b)]	15,431	23,241	28,002
Wyoming Electric	5,471	5,215	8,179
Colorado Electric	1,453	1,270	5,726
Total Off-system/Power Marketing Wholesale	22,355	29,726	41,907
Other Revenue: [(c)]			
South Dakota Electric	28,387	26,954	25,826
Wyoming Electric	920	2,374	2,253
Colorado Electric	5,087	4,931	7,691
Total Other Revenue	34,394	34,259	35,770
Total Revenue - Electric	$677,281	$679,843	$657,556

(a) Increase is driven primarily by load growth supporting data centers in Cheyenne, Wyoming.
(b) Decrease is due to lower commodity prices that reduced gross sales.
(c) Other revenue primarily consists of transmission revenue.

Quantities Generated and Purchased (MWh)	2016	2015	2014
Generated:			
Coal-fired:			
South Dakota Electric [(a)(b)]	1,467,403	1,537,744	1,591,061
Wyoming Electric [(c)]	734,354	690,633	697,220
Total Coal - fired	2,201,757	2,228,377	2,288,281
Natural Gas and Oil:			
South Dakota Electric [(a)(d)]	118,467	80,944	44,984
Wyoming Electric [(a)(d)]	70,997	48,644	12,534
Colorado Electric [(e)]	153,537	100,732	140,942
Total Natural Gas and Oil	343,001	230,320	198,460
Wind:			
Colorado Electric [(f)]	80,582	41,043	48,318
Total Wind	80,582	41,043	48,318
Total Generated:			
South Dakota Electric	1,585,870	1,618,688	1,636,045
Wyoming Electric	805,351	739,277	709,754
Colorado Electric	234,119	141,775	189,260
Total Generated	2,625,340	2,499,740	2,535,059
Purchased:			
South Dakota Electric	1,181,445	1,422,015	1,446,630
Wyoming Electric	872,070	791,351	766,475
Colorado Electric [(e)]	1,911,537	1,952,625	1,898,232
Total Purchased [(g)]	3,965,052	4,165,991	4,111,337
Total Generated and Purchased	6,590,392	6,665,731	6,646,396

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(a) Natural gas-fired generation from Cheyenne Prairie increased in 2016 primarily due to lower coal fired generation driven by 2016 outages at the coal-fired Wyodak plant.
(b) Neil Simpson I was retired on March 21, 2014.
(c) Increase in 2016 was due to a 2015 planned annual outage at Wygen II.
(d) Cheyenne Prairie was placed into commercial service on October 1, 2014.
(e) Lower commodity prices drove an increase in generation and a corresponding decrease in purchased power.
(f) Increase in 2016 is due to the addition of the Peak View Wind Project in November 2016.
(g) Includes wind power of 269,552 MWh, 227,396 MWh and 224,229 MWh in 2016, 2015 and 2014, respectively.

Quantities Sold (MWh)	2016	2015	2014
Residential:			
South Dakota Electric	520,798	521,828	542,008
Wyoming Electric	257,593	256,964	261,038
Colorado Electric	616,706	621,109	598,872
Total Residential	1,395,097	1,399,901	1,401,918
Commercial:			
South Dakota Electric	783,319	792,466	782,238
Wyoming Electric	531,446	532,218	528,689
Colorado Electric	752,721	706,872	685,094
Total Commercial	2,067,486	2,031,556	1,996,021
Industrial:			
South Dakota Electric	429,912	429,140	399,648
Wyoming Electric [a]	650,810	498,141	382,306
Colorado Electric	434,831	472,360	432,167
Total Industrial	1,515,553	1,399,641	1,214,121
Municipal:			
South Dakota Electric	33,591	31,924	32,076
Wyoming Electric	9,400	9,714	9,425
Colorado Electric	119,392	117,858	122,247
Total Municipal	162,383	159,496	163,748
Subtotal Retail Quantity Sold	5,140,519	4,990,594	4,775,808
Contract Wholesale:			
Total Contract Wholesale - South Dakota Electric [b]	246,630	260,893	340,871
Off-system Wholesale:			
South Dakota Electric [c]	597,695	837,120	808,257
Wyoming Electric	110,621	121,659	191,069
Colorado Electric	61,527	41,306	119,315
Total Off-system Wholesale	769,843	1,000,085	1,118,641
Total Quantity Sold:			
South Dakota Electric	2,611,945	2,873,371	2,905,098
Wyoming Electric	1,559,870	1,418,696	1,372,527
Colorado Electric	1,985,177	1,959,505	1,957,695
Total Quantity Sold	6,156,992	6,251,572	6,235,320
Other Uses, Losses or Generation, net [d]:			
South Dakota Electric	155,370	167,332	177,577
Wyoming Electric	117,551	111,932	103,702
Colorado Electric	160,479	134,895	129,797
Total Other Uses, Losses and Generation, net	433,400	414,159	411,076
Total Energy Sold	6,590,392	6,665,731	6,646,396

(a) Year over year increases since 2014 are driven by new load supporting data centers in Cheyenne, Wyoming.

(b) Decrease in 2015 is primarily due to the expiration in March 2015 of a 5 MW unit contingent capacity contract with MEAN.

(c) Decrease in 2016 is driven by weaker market conditions.

(d) Includes Company uses, line losses, test energy and excess exchange production.

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Customers at End of Year	2016	2015	2014
Residential:			
South Dakota Electric	57,712	57,178	56,511
Wyoming Electric	36,748	36,438	36,253
Colorado Electric	83,873	83,285	82,710
Total Residential	178,333	176,901	175,474
Commercial:			
South Dakota Electric	13,278	13,197	13,173
Wyoming Electric	4,560	4,760	4,489
Colorado Electric	11,248	11,215	11,156
Total Commercial	29,086	29,172	28,818
Industrial:			
South Dakota Electric	21	20	23
Wyoming Electric	5	4	4
Colorado Electric	62	63	66
Total Industrial	88	87	93
Other Electric Customers:			
South Dakota Electric	340	335	325
Wyoming Electric	218	220	224
Colorado Electric	441	469	469
Total Other Electric Customers	999	1,024	1,018
Subtotal Retail Customers	208,506	207,184	205,403
Contract Wholesale:			
Total Contract Wholesale - South Dakota Electric	2	3	3
Total Customers:			
South Dakota Electric	71,353	70,733	70,035
Wyoming Electric	41,531	41,422	40,970
Colorado Electric	95,624	95,032	94,401
Total Electric Customers at End of Year	208,508	207,187	205,406

Gas Utilities Segment

We conduct natural gas utility operations through our Arkansas, Colorado, Iowa, Kansas, Wyoming and Nebraska subsidiaries. On February 12, 2016, we acquired SourceGas Holdings, LLC, adding four regulated natural gas utilities serving approximately 431,000 customers in Arkansas, Colorado, Nebraska and Wyoming and a 512 mile regulated intrastate natural gas transmission pipeline in Colorado. Our Gas Utilities distribute and transport natural gas through our distribution network to approximately 1,030,800 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 Black Hills Energy Services. Black Hills Energy Services has approximately 55,000 retail distribution customers in Nebraska and Wyoming providing unbundled natural gas commodity offerings under the regulatory-approved Choice Gas Program. We also sell, install and service air, heating and water-heating equipment, and provide associated repair service and appliance protection plans under various trade names. Service Guard and CAPP primarily provide appliance repair services to approximately 61,000, and 33,000 residential customers, respectively, 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 and maintaining customer-owned gas infrastructure facilities, typically through one-time contracts.

Our Gas Utilities own regulated underground gas storage facilities in several states primarily to supplement the supply of natural gas to our customers in periods of peak demand. The following table summarizes certain information regarding our regulated underground gas storage facilities as of December 31, 2016:

State	Working Capacity (Mcf)	Cushion Gas (Mcf) [(a)]	Total Capacity (Mcf)	Maximum Daily Withdrawal Capability (Mcfd)
Arkansas	8,442,700	12,950,000	21,392,700	196,000
Colorado	2,168,721	6,063,249	8,231,970	30,000
Wyoming	6,813,400	17,270,200	24,083,600	32,950
Total	17,424,821	36,283,449	53,708,270	258,950

(a) Cushion gas represents the volume of gas that must be retained in a facility to maintain reservoir pressure.

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

System Infrastructure (in line miles) as of December 31, 2016	Intrastate Gas Transmission Pipelines	Gas Distribution Mains	Gas Distribution Service Lines
Arkansas	886	4,572	906
Colorado	678	6,481	2,323
Nebraska	1,249	8,330	3,319
Iowa	180	2,740	2,639
Kansas	293	2,826	1,328
Wyoming	1,299	3,372	1,208
Total	4,585	28,321	11,723

Degree Days

	2016			2015			2014	
	Actual	Variance From Prior Year	Variance From 30-Year Average [d]	Actual	Variance From Prior Year	Variance From 30-Year Average [d]	Actual	Variance From 30-Year Average [d]
Heating Degree Days:								
Arkansas [a]	2,397	—%	(10)%	—	—%	—%	—	—%
Colorado	5,762	4%	(9)%	5,527	(10)%	(12)%	6,108	(3)%
Nebraska	5,457	2%	(12)%	5,350	(14)%	(12)%	6,193	2%
Iowa	5,997	(10)%	(12)%	6,629	(16)%	(2)%	7,875	16%
Kansas [b]	4,307	(3)%	(12)%	4,432	(13)%	(9)%	5,099	4%
Wyoming	6,750	5%	(8)%	6,404	(10)%	(10)%	7,100	—%
Combined [c]	5,823	(1)%	(10)%	5,890	(13)%	(8)%	6,805	6%

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(a) Arkansas has a weather normalization mechanism in effect during the months of November through April for those customers with residential and business rate schedules. The weather normalization mechanism in Arkansas only uses one location to calculate the weather, minimizing, but not eliminating weather impact.

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

(c) 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.

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

Operating Statistics

Gas Utilities Revenue (in thousands)	2016	2015	2014
Residential:			
Arkansas	$59,675	$ —	$ —
Colorado	102,468	55,216	58,439
Nebraska	98,300	111,090	135,052
Iowa	80,480	90,865	124,145
Kansas	56,284	61,420	74,128
Wyoming	35,899	23,554	24,426
Total Residential	433,106	342,145	416,190
Commercial:			
Arkansas	29,460	—	—
Colorado	36,431	10,744	12,233
Nebraska	27,742	32,798	39,947
Iowa	33,119	39,314	60,640
Kansas	18,241	21,802	24,966
Wyoming	17,554	12,916	11,279
Total Commercial	162,547	117,574	149,065
Industrial:			
Arkansas	4,904	—	—
Colorado	1,837	1,433	1,909
Nebraska	458	1,339	830
Iowa	1,777	2,633	4,386
Kansas	8,892	12,887	16,963
Wyoming	3,377	4,106	2,945
Total Industrial	21,245	22,398	27,033
Other:			
Arkansas	2,644	—	—
Colorado	1,006	464	118
Nebraska	3,479	2,271	2,440
Iowa	506	580	724
Kansas	4,177	4,475	2,836
Wyoming	882	275	267
Total Other	12,694	8,065	6,385
Distribution Revenue:			
Arkansas	96,683	—	—
Colorado	141,742	67,857	72,699
Nebraska	129,979	147,498	178,269
Iowa	115,882	133,392	189,895
Kansas	87,594	100,584	118,893
Wyoming	57,712	40,851	38,917
Total Distribution Revenue	629,592	490,182	598,673
Transportation:			
Arkansas	8,348	—	—

Colorado	3,752	1,037	968
Nebraska [(a)]	66,241	13,427	14,272
Iowa	4,844	4,762	4,934
Kansas	6,611	7,280	7,448
Wyoming [(a)]	21,962	3,310	838
Total Transportation	111,758	29,816	28,460

Transmission:			
Arkansas	1,339	—	—
Colorado	21,713	—	—
Wyoming	4,680	—	—
Total Transmission	27,732	—	—
Total Regulated Revenue	769,082	519,998	627,133
Non-regulated Services	69,261	31,302	30,390
Total Revenue	$838,343	$551,300	$657,523

Gas Utilities Gross Margin (in thousands)	2016	2015	2014
Residential:			
Arkansas	$39,324	$ —	$ —
Colorado	42,853	18,153	18,100
Nebraska	51,953	51,168	54,996
Iowa	42,030	41,638	44,134
Kansas	30,794	31,789	32,809
Wyoming	21,558	13,011	11,615
Total Residential	228,512	155,759	161,654
Commercial:			
Arkansas	16,119	—	—
Colorado	13,128	2,921	3,048
Nebraska	10,942	10,822	11,708
Iowa	11,620	11,662	13,206
Kansas	7,419	8,409	8,115
Wyoming	8,147	4,678	3,582
Total Commercial	67,375	38,492	39,659
Industrial:			
Arkansas	1,776	—	—
Colorado	670	395	464
Nebraska	194	393	239
Iowa	215	253	294
Kansas	2,020	2,529	2,336
Wyoming	726	733	525
Total Industrial	5,601	4,303	3,858
Other:			
Arkansas	2,644	—	—
Colorado	1,006	464	118
Nebraska	3,479	2,271	2,441
Iowa	506	580	724
Kansas	4,177	4,405	1,990
Wyoming	882	275	266
Total Other	12,694	7,995	5,539

Distribution Gross Margin:			
Arkansas	59,863	—	—
Colorado	57,657	21,933	21,730
Nebraska	66,568	64,654	69,384
Iowa	54,371	54,133	58,358
Kansas	44,410	47,132	45,250
Wyoming	31,313	18,697	15,988
Total Distribution Gross Margin	314,182	206,549	210,710

Transportation:			
Arkansas	8,348	—	—
Colorado	3,752	1,037	968
Nebraska [(a)]	66,241	13,427	14,272
Iowa	4,844	4,762	4,934
Kansas	6,611	7,280	7,448
Wyoming [(a)]	21,962	3,310	838
Total Transportation	111,758	29,816	28,460
Transmission:			
Arkansas	1,339	—	—
Colorado	21,504	—	—
Wyoming	4,681	—	—
Total Transmission	27,524	—	—
Total Regulated Gross Margin:			
Arkansas	69,550	—	—
Colorado	82,913	22,970	22,698
Nebraska	132,809	78,081	83,656
Iowa	59,215	58,895	63,292
Kansas	51,021	54,412	52,698
Wyoming	57,956	22,007	16,826
Total Regulated Gross Margin	453,464	236,365	239,170
Non-regulated Services	32,714	15,290	14,572
Total Gross Margin	$486,178	$251,655	$253,742

Gas Utilities Quantities Sold and Transported (in Dth)	2016	2015	2014
Residential:			
Arkansas	6,052,792	—	—
Colorado	12,634,407	6,575,261	6,718,508
Nebraska	10,676,153	10,751,376	13,068,132
Iowa	9,567,386	9,648,973	12,172,281
Kansas	5,866,246	6,091,041	7,313,273
Wyoming	4,593,467	2,583,049	2,515,243
Total Residential	49,390,451	35,649,700	41,787,437
Commercial:			
Arkansas	4,111,136	—	—
Colorado	4,676,332	1,404,624	1,537,704
Nebraska	3,986,531	4,026,689	4,644,645
Iowa	5,425,789	5,492,230	7,182,173
Kansas	2,564,759	2,768,486	3,043,685
Wyoming	3,273,314	2,073,213	1,482,904
Total Commercial	24,037,861	15,765,242	17,891,111
Industrial:			
Arkansas	983,881	—	—

Colorado	440,174	288,212	354,630
Nebraska	86,905	246,184	122,662
Iowa	398,871	481,760	630,912
Kansas	2,914,538	3,346,525	3,384,797
Wyoming	913,061	845,774	539,848
Total Industrial	5,737,430	5,208,455	5,032,849

Wholesale and Other:			
Kansas	—	14,902	150,014
Total Wholesale and Other	—	14,902	150,014
Distribution Quantities Sold:			
Arkansas	11,147,809	—	—
Colorado	17,750,913	8,268,097	8,610,842
Nebraska	14,749,589	15,024,249	17,835,439
Iowa	15,392,046	15,622,963	19,985,366
Kansas	11,345,543	12,220,954	13,891,769
Wyoming	8,779,842	5,502,036	4,537,995
Total Distribution Quantities Sold	79,165,742	56,638,299	64,861,411
Transportation:			
Arkansas	7,292,299	—	—
Colorado	2,552,756	1,019,933	950,819
Nebraska (a)	53,046,432	28,968,737	30,669,764
Iowa	19,991,944	19,867,265	19,959,462
Kansas	15,117,771	15,865,783	15,883,098
Wyoming (a)	19,870,602	11,672,057	9,970,123
Total Transportation	117,871,804	77,393,775	77,433,266
Transmission:			
Arkansas	737,330	—	—
Colorado (b)	3,353,222	—	—
Wyoming	4,965,209	—	—
Total Transmission	9,055,761	—	—
Total Quantities Sold and Transportation:			
Arkansas	19,177,438	—	—
Colorado	23,656,891	9,288,030	9,561,661
Nebraska	67,796,021	43,992,986	48,505,203
Iowa	35,383,990	35,490,228	39,944,828
Kansas	26,463,314	28,086,737	29,774,867
Wyoming	33,615,653	17,174,093	14,508,118
Total Quantities Sold and Transportation	206,093,307	134,032,074	142,294,677

(a) Increased transportation in Nebraska and parts of Wyoming is due to Choice Gas Program customers acquired in the SourceGas Acquisition.
(b) Intercompany volumes from RMNG's transmission system to Black Hills Gas Distribution are not included.

Customers at End of Year	2016	2015	2014
Residential:			
Arkansas	148,513	—	—
Colorado	160,153	74,345	72,360
Nebraska	184,794	180,897	180,014
Iowa	140,007	139,205	138,503
Kansas	99,748	99,013	99,359
Wyoming	67,765	39,953	32,962
Total Residential	800,980	533,413	523,198
Commercial:			
Arkansas	17,638	—	—
Colorado	16,777	3,825	3,788
Nebraska	16,147	15,948	15,900
Iowa	15,435	15,433	15,303
Kansas	10,747	10,813	10,547
Wyoming	7,305	4,156	3,052
Total Commercial	84,049	50,175	48,590
Industrial:			
Arkansas	213	—	—
Colorado	275	224	205
Nebraska	126	145	147
Iowa	94	98	90
Kansas	1,324	1,377	1,277
Wyoming	18	15	7
Total Industrial	2,050	1,859	1,726
Transportation:			
Arkansas	148	—	—
Colorado	189	40	34
Nebraska (a)	88,586	4,271	4,151
Iowa	478	460	418
Kansas	1,138	1,161	1,145
Wyoming (a)	53,134	30	12
Total Transportation	143,673	5,962	5,760
Wholesale:			
Kansas (b)	—	—	8
Total Wholesale	—	—	8
Total Customers:			
Arkansas	166,512	—	—
Colorado	177,394	78,434	76,387
Nebraska	289,653	201,261	200,212
Iowa	156,014	155,196	154,314
Kansas	112,957	112,364	112,336
Wyoming	128,222	44,154	36,033
Total Customers at End of Year	1,030,752	591,409	579,282

(a) Increased transportation in Nebraska and parts of Wyoming is due to Choice Gas Program customers acquired in the SourceGas Acquisition.

(b) Change in customers is due to classification change to Commercial billing in 2015 based on customer’s business type.

Electric Utilities and Gas Utilities 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, these initiatives have not had a material impact on 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 Electric Utilities operate:

Subsidiary	Jurisdic-tion	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Authorized Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Tariff and Rate Matters	Percentage of Power Marketing Profit Shared with Customers
Electric Utilities:								
South Dakota Electric	WY	9.9%	8.13%	46.7%/53.3%	$46.8	10/2014	ECA	65%
	SD	Global Settlement	7.76%	Global Settlement	$543.9	10/2014	ECA, TCA, Energy Efficiency Cost Recovery/DSM, Vegetation Management	70%
	SD		7.76%			6/2011	Environmental Improvement Cost Recovery Adjustment Tariff	N/A
	MT	15.0%	11.73%	47%/53%		1983	ECA	N/A
	FERC	10.8%	9.10%	43%/57%		2/2009	FERC Transmission Tariff	N/A
Wyoming 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
Colorado Electric	CO	9.37%	7.43%	47.6%/52.4%	$539.6	1/2017	ECA, TCA, PCCA, Energy Efficiency Cost Recovery/DSM, Renewable Energy Standard Adjustment	90%
	CO	9.37%	6.02%	67.3%/32.7%	$57.9	1/2017	Clean Air Clean Jobs Act Adjustment Rider	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.

The significant mechanisms we have in place include the following by utility and state:

In South Dakota, South Dakota Electric 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 70% of off-system power marketing operating income. The ECA methodology allows us 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.

- An approved vegetation management recovery mechanism that allows for recovery of and a return on prudently-incurred vegetation management costs.

- An approved annual Environmental Improvement Cost Recovery Adjustment tariff which recovers costs associated with generation plant environmental improvements.

- An approved FERC Transmission Tariff based on a formulaic approach that determines the revenue component of South Dakota Electric’s open access transmission tariff.

In Wyoming, Wyoming Electric has:

- An annual cost adjustment mechanism that allows us to pass the prudently-incurred costs of fuel and purchased power through to electric customers. As of October 1, 2014, the annual cost adjustment allows for recovery of 85% of coal and coal-related costs, and recovery of 95% of purchased power costs, transmission, and natural gas costs.

- An approved FERC Transmission Tariff that determines the revenue component of Wyoming Electric's open access transmission tariff.

In Colorado, Colorado Electric has:

- A quarterly ECA rider 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%). 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.

- 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.

- The Clean Air Clean Jobs Act Adjustment rider rate collects the authorized revenue requirement for the LM6000 generating unit placed in service on December 31, 2016 with rates effective January 1, 2017.

- The Renewable Energy Standard Adjustment rider is specifically designed for meeting the requirements of Colorado's renewable energy standard and most recently includes cost recovery for the Peak View Wind Project.

Electric Utilities Rates and Rate Activity

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

	Type of Service	Date Requested	Effective Date	Revenue Amount Requested	Revenue Amount Approved
Colorado Electric [(a)]	Electric	5/2016	1/2017	$ 8.9	$ 1.2

(a) On December 19, 2016, Colorado Electric received approval from the CPUC to increase its annual revenues by $1.2 million to recover investments in a $63 million, 40 MW natural gas-fired combustion turbine and normal increases in operating expenses. This increase is in addition to approximately $5.9 million in annualized revenue being recovered under the Clean Air Clean Jobs Act construction financing rider. This turbine was completed in the fourth quarter of 2016, achieving commercial operation on December 29, 2016. The approval allowed a return on rate base of 6.02% for this turbine, with a 9.37% return on equity and a capital structure of 67.34% debt and 32.66% equity. Whereas, an authorized return on rate base of 7.4% was received for the remaining system investments, with a return on equity of 9.37% and an approved capital structure of 47.6% debt and 52.4% equity.

On January 9, 2017, we filed an application with the CPUC for rehearing, reargument or reconsideration of the Commission's December 19, 2016 decision which reduced our proposed $8.9 million annual revenue increase to $1.2 million. Concurrent with this application, we filed a motion for Commissioner Koncilja to recuse herself from continuing to participate in any further proceedings in the rate review.

We believe the CPUC made errors in their December decision by demonstrating bias, making decisions not supported by evidence, making findings inconsistent with cost-recovery provisions of the Colorado Clean Air-Clean Jobs Act and the Commission's own prior decisions, and treating Colorado Electric differently than other regulated utilities in Colorado have been treated in similar situations.

Our Gas Utilities are authorized to use natural gas cost recovery mechanisms that allow them to adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure that they recover all the costs prudently incurred in purchasing gas for their customers. In addition to natural gas recovery mechanisms, we have other cost recovery mechanisms, such as regulatory riders, which vary by utility but allow us to recover certain costs, such as those related to energy efficiency plans and system safety and integrity investments. The following table provides regulatory information for each of our natural gas utilities:

Subsidiary	Jurisdic-tion	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Authorized Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Tariff and Rate Matters
Gas Utilities:							
Arkansas Gas [(a)]	AR	9.4%	6.47% [(b)]	52%/48%	$299.4 [(c)]	2/2016	Gas Cost Adjustment, Main Replacement Program, At-Risk Meter Replacement Program, Legislative/Regulatory Mandate and Relocations Rider, Energy Efficiency, Weather Normalization Adjustment, Billing Determinant Adjustment
Colorado Gas	CO	9.6%	8.41%	50%/50%	$64.0	12/2012	GCA, Energy Efficiency Cost Recovery/DSM
Colorado Gas Dist.[(a)]	CO	10.0%	8.02%	49.52%/ 50.48%	$127.1	12/2010	Gas Cost Adjustment, DSM
RMNG [(a)]	CO	10.6%	7.93%	49.23%/ 50.77%	$90.5	3/2014	System Safety Integrity Rider, Liquids/Off-system/Market Center Services Revenue Sharing
Iowa Gas	IA	Global Settlement	Global Settlement	Global Settlement	$109.2	2/2011	GCA, Energy Efficiency Cost Recovery/DSM/Capital Infrastructure Automatic Adjustment Mechanism
Kansas Gas	KS	Global Settlement	Global Settlement	Global Settlement	$127.4	1/2015	GCA, Weather Normalization Tariff, Gas System Reliability Surcharge, Ad Valorem Tax Surcharge, Cost of Bad Debt Collected through GCA, Pension Levelized Adjustment
Nebraska Gas	NE	10.1%	9.11%	48%/52%	$161.3	9/2010	GCA, Cost of Bad Debt Collected through GCA, Infrastructure System Replacement Cost Recovery Surcharge
Nebraska Gas Dist. [(a)]	NE	9.6%	7.67%	48.84%/ 51.16%	$87.6/$69.8 [(d)]	6/2012	Choice Gas Program, System Safety and Integrity Rider, Bad Debt expense recovered through Choice supplier fee
	WY	9.9%	7.98%	46%/54%	$59.6	10/2014	

Wyoming Gas							GCA, Energy Efficiency Cost Recovery/DSM, Rate Base Recovery on Acquisition Adjustment
Wyoming Gas Dist. (a)	WY	9.92%	7.98%	49.66%/ 50.34%	$100.5	1/2011	Choice Gas Program, Purchased Gas Cost Adjustment, Usage Per Customer Adjustment

(a) Acquired through SourceGas

(b) Arkansas return on rate base adjusted to remove current liabilities from rate case capital structure for comparison with other subsidiaries.

(c) Arkansas rate base is adjusted to include current liabilities for comparison with other subsidiaries.

(d) Total Nebraska rate base of $87.6 million includes amounts allocated to serve non-jurisdictional and agricultural customers. Jurisdictional Nebraska rate base of $69.8 million excludes those amounts allocated to serve non-jurisdictional and agricultural customers and is used for calculation of jurisdictional base rates.

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

Gas Utility Jurisdiction	Cost Recovery Mechanisms						
	DSM/Energy Efficiency	Integrity Additions	Bad Debt	Weather Normal	Pension Recovery	Fuel Cost	Revenue Decoupling
Arkansas Gas	þ	þ		þ		þ	
Colorado Gas	þ					þ	
Colorado Gas Dist.	þ					þ	
Rocky Mountain Natural Gas	N/A	þ	N/A	N/A	N/A	N/A	N/A
Iowa Gas	þ	þ				þ	
Kansas Gas		þ	þ	þ	þ	þ	
Nebraska Gas		þ	þ			þ	
Nebraska Gas Dist.		þ	þ			þ	
Wyoming Gas	þ					þ	
Wyoming Gas Dist.						þ	þ

Gas Utilities Rates and Rate Activity

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

	Type of Service	Date Requested	Effective Date	Revenue Amount Requested	Revenue Amount Approved
Arkansas Gas [(a)]	Gas	4/2015	2/2016	$ 12.6	$ 8.0
Arkansas Stockton Storage [(b)]	Gas - storage	11/2016	1/2017	$ 2.6	$ 2.6
Arkansas MRP/ARMRP [(c)]	Gas	1/2017	1/2017	$ 1.7	$ 1.7
RMNG [(d)]	Gas - transmission and storage	11/2016	1/2017	$ 2.9	$ 2.9
Nebraska Gas Dist. [(e)]	Gas	10/2016	2/2017	$ 6.5	$ 6.5

(a) In February 2016, Arkansas Gas implemented new base rates resulting in a revenue increase of $8.0 million. The APSC modified a stipulation reached between the APSC Staff and all intervenors except the Attorney General and Arkansas Gas in its order issued on January 28, 2016. The modified stipulation revised the capital structure to 52% debt and 48% equity and also limited recovery of portions of cost related to incentive compensation.

(b) On November 15, 2016, Arkansas Gas filed for recovery of Stockton Storage revenue requirement through the Stockton Storage Acquisition Rates regulatory mechanism, approved on October 15, 2015, with rates effective January 1, 2017.

(c) On January 3, 2017 Arkansas Gas filed for recovery of $1.5 million related to projects for the replacement of eligible mains (MRP) and the recovery of $0.2 million related to projects for the relocation of certain at risk meters (ARMRP). Pursuant to the Arkansas Gas Tariff, the filed rates go into effect on the date of the filing.

(d) On November 3, 2016, RMNG filed with the CPUC requesting recovery of $2.9 million, which includes $1.2 million of new revenue related to system safety and integrity expenditures on projects for the period of 2014 through 2017. This SSIR request was approved by the CPUC in December 2016, and went into effect on January 1, 2017.

(e) On October 3, 2016, Nebraska Gas Dist. filed with the NPSC requesting recovery of $6.5 million, which includes $1.7 million of new revenue related to system safety and integrity expenditures on projects for the period of 2012 through 2017. This SSIR tariff was approved by the NPSC in January 2017, and will go into effect on February 1, 2017.

Cost of Service Gas Program Filings

On September 30, 2015, Black Hills Corp.'s utility subsidiaries submitted applications with respective state utility regulators seeking approval for a Cost of Service Gas Program in Iowa, Kansas, Nebraska, South Dakota and Wyoming. An application was submitted in Colorado on November 2, 2015. The Cost of Service Gas Program is designed to provide long-term natural gas price stability for the Company's utility customers, along with a reasonable expectation of customer savings over the life of the program. As originally proposed, our non-utility affiliate would acquire natural gas reserves and/or drill wells to produce natural gas for the program for up to 50% of weather normalized annual firm demand for our utilities. The Cost of Service Gas Program model had a capital structure of 60% equity and 40% debt, and sought a utility-like return.

During the third quarter of 2016, the Company withdrew its Cost of Service Gas applications in Wyoming, Iowa, Kansas and South Dakota. In consideration of the July 19, 2016 denial of the application from the NPSC and the April 2016 dismissal of its application from the CPUC, the Company is re-evaluating its Cost of Service Gas regulatory approval strategy.

The Company's initial applications submitted in late 2015 were based on a two-phase approach, the first of which would establish the regulatory framework for how the program would work, and the second would seek approval for a specific gas reserve property. The orders in Colorado and Nebraska indicated the initial phase filings contained insufficient information and data to support customer benefits. Based on the findings and outcomes of the initial unsuccessful filings, the Company is considering filing new applications for approval of specific gas reserve properties.

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. As of December 31, 2016, 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.

Colorado Electric received a settlement agreement of its electric resource plan filed June 3, 2016, to meet requirements under the Colorado Renewable Energy Standard. The settlement, effective February 6, 2017, includes the addition of 60 megawatts of renewable energy to be in service by 2019 and provides for additional small solar and community solar gardens as part of the compliance plan. Colorado Electric plans to issue a request for proposal in the first half of 2017.

On November 7, 2016, Colorado Electric took ownership of Peak View, a $109 million, 60 MW Wind Project located near Colorado Electric's Busch Ranch Wind Farm. Peak View achieved commercial operation on November 7, 2016 and was purchased via progress payments throughout 2016 under a commission approved third-party build transfer and settlement agreement. This renewable energy project was originally submitted in response to Colorado Electric's all-source generation request on May 5, 2014. The Commission's settlement agreement provides for recovery of the costs of the project through Colorado Electric's Electric Cost Adjustments and Renewable Energy Standard Surcharge for 10 years and recovery through the Transmission Cost Adjustment, after which Colorado Electric can propose base rate recovery. Colorado Electric will be required to make an annual comparison of the cost of the renewable energy generated by the facility against the bid cost of a PPA from the same facility.

- 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, South Dakota Electric 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 South Dakota Electric 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 would likely 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. South Dakota Electric 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.

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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. The results of the 2016 U.S. elections add uncertainty as to the final disposition of recently enacted and proposed EPA regulations.

Environmental Expenditure Estimates	Total (in thousands)
2017	$ 1,209
2018	3,867
2019	1,773
Total	$ 6,849

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 and published the final rule on November 3, 2015. This rule will have an impact on the Wyodak Plant, requiring conversion to a dry method of handling coal ash and further restrictions of constituent concentrations in any off-site discharges. Our share of those costs is estimated at $1.8 million. The terms of this new regulation become effective at the next permit renewal, which will be in 2020. 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.

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 2046. 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 2017. The Pueblo Airport Generating Station Title V application was filed in September 2012, with the permit expected in 2017. The Cheyenne Prairie Generating Station Title V application was submitted in 2015, with the permit expected in 2017. All applications were filed in accordance with regulatory requirements.

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. As of April 16, 2016, all plants are in compliance.

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 2017 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.

The EPA published a more stringent ozone ambient standard on October 26, 2015. This regulation lowered the ozone standard from 75 to 70 ppb which will result in a continuation of the Denver, Colorado and Colorado North Front Range non-attainment status. Wyoming monitoring data from the Gillette and Cheyenne, Wyoming regions indicate compliance with the new limit. The primary impact on Black Hills operations could potentially be tighter NO_x emission limits on new power generation units.

Regional Haze

The Regional Haze Program is an EPA rule to improve visibility in our National Parks and Wilderness Areas. The state of Wyoming is currently developing its 2017 initial progress report under the EPA's Regional Haze Program. Neil Simpson II is not currently a discussion item in that draft report, but could be in the future.

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, which is anticipated to be settled by the summer of 2017.

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.

We report GHG emissions for all power generation facilities, gas distribution systems, transmission and compression systems, and oil and gas exploration and production systems. All data is reported through and available on the U.S. Department of Energy's (DOE) Energy Information Administration's and EPA's GHG reporting website. For all gas distribution systems, we include U.S. DOT Pipeline and Hazardous Materials Safety Administration (PHMSA) leak surveys of all underground and aboveground facilities including Forward Looking Infrared Camera reviews of 20% of our sites on a rotating annual basis.

The GHG Tailoring Rule, effective June 2010, 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, published October 2015, effectively prohibits new coal-fired units until carbon capture and sequestration becomes technically and economically feasible.

The portion of this rule-making that applies to existing power generation sources is known as the Clean Power Plan (CPP). The portion of this rule-making that applies to new generating units effectively prohibits new coal-fired power plants from being constructed until carbon capture and sequestration becomes technically and economically feasible. The objective of the CPP regulation is to decrease existing coal-fired generation, increase the utilization of existing gas-fired combined cycle generation, increase renewable energy and increase use of demand side management. The U.S. Supreme Court entered an order staying the CPP in February 2016, pending appeal. The effect of the order is to delay the CPP’s compliance deadlines until challenges to the CPP have been fully litigated and the U.S. Supreme Court has ruled. If the CPP is implemented in its current form, we cannot predict the terms of state plans and any 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 2015 and again in 2016, we met with staff of state air programs and public utility commissions on several occasions. We will continue to work closely with state regulatory staff as these plans develop.

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 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.

In 2016, we reported 2015 GHG emissions from our Power Generation and Gas Utilities in order to comply with the EPA's GHG Annual Inventory regulation. 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 and/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. The results of the 2016 U.S. elections add uncertainty as to the final disposition of recently enacted and proposed EPA regulations, including the CPP. We will continue to monitor new developments for potential impacts to our operations.

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 ash disposal sites. Ash and waste from flue gas, sulfur and mercury removal from the Wyodak, 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 and as part of the five year mine permit renewal process completed in 2016, the state has confirmed approval of this practice. 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 and a small industrial rubble landfill. Site closure work was completed and the state issued an approval of closure activities on October 21, 2014. Post-closure monitoring activities of the ash impoundment and small industrial rubble landfill will continue for 30 years from that date. 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 Generating 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 require 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 Energy South Dakota has a similar agreement in place for any such costs related to solid waste from Wygen III. Under their separate but related operating agreements, Black Hills Energy South Dakota, 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 of our coal ash is used as mine backfill. However, it is expected that the U.S. Office of Surface Mining will develop similar regulations, anticipated to be proposed in 2017. The 2016 presidential election results add uncertainty as to what the U.S. Office of Surface Mining will propose. We will continue to monitor new developments for potential impacts to our operations.

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 $1.5 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 of Nebraska Gas to remediate two sites in Nebraska (Blair and Plattsmouth). These sites were remediated through the state voluntary cleanup program. Site remediation was completed in 2012 and ground water monitoring ended in 2015. We assembled our final removal action completion reports to formally close the site, and submitted reports to the Nebraska Department of Environmental Quality in December 2015. In 2016, we received state approval for “no further action” at both sites. The successor is also responsible for remediation activity at the two remaining sites in Nebraska (Columbus and Norfolk). While the successor has performed remediation work at Columbus and Norfolk, due to disagreements between the state of Nebraska and the successor over management of remaining groundwater contamination, the EPA in 2016 placed the Norfolk site on the National Priority List. We are not a named financially responsible party to this action. We cannot be assured of the financial impact to us as property owner until the process has run its course.

As of December 31, 2016, we estimate a range of approximately $2.6 million to $6.1 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. In 2016, as part of a nationwide assessment of such sites, the EPA performed sampling to determine current contamination levels. Results confirmed previously known levels of contamination. While there are no regulatory actions to date requiring remediation, we are assessing the situation to determine a path forward.

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.

As a result of the SourceGas Transaction, we acquired potential liability for at least one former MGP site in McCook, Nebraska. The Nebraska Department of Environmental Quality conducted a limited assessment in 2012 which documented soil and groundwater impacts. However, there has been no directive from the state to pursue either remediation or further assessment. We are currently evaluating the potential for other Potential Responsible Parties and future comprehensive analyses to fully determine and delineate the extent of contamination. The assigned liability for this site cannot be determined at this time. However, based on the state’s assessment, we anticipate costs will be less than $1.0 million.

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, 2016, 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, 2016, 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 [(a)]	Gas	Pueblo, Colorado	50.1%	200.0	2012
				268.9	

(a) 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 Wyoming Electric under a PPA that expires on December 31, 2022. The PPA includes an option for Wyoming Electric 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 MW 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, 2016 was $73 million and if Wyoming Electric had exercised the purchase option at year-end 2016, the estimated purchase price would have been approximately $139 million and would be subject to WPSC and FERC approval in order to obtain regulatory treatment. Wyoming Electric has delayed consideration of exercising the purchase option pending the state of Wyoming finalizing their State Implementation Plans to comply with the EPA's CPP. Wyoming originally had until September 30, 2016 to submit their final plans to the EPA. However a two-year extension has been allowed under the rule, which Wyoming has applied for and received. The U.S. Supreme Court's stay of the CPP and the results of the 2016 U.S elections add uncertainty as to the final disposition of recently enacted and proposed EPA regulations, including the CPP. 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 Generating 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, which expires on December 31, 2031. Under the PPA with Colorado Electric, any excess capacity and energy shall be for the benefit of Colorado Electric.

Sale of Noncontrolling Interest in Subsidiary

On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for $216 million to a third party buyer. FERC approval of the sale was received on March 29, 2016. Black Hills Electric Generation is the operator of the facility, which is contracted to provide capacity and energy through 2031 to Black Hills Colorado Electric. Proceeds from the sale were used to pay down short-term debt and for other general corporate purposes. The operating results for Black Hills Colorado IPP remain consolidated with Black Hills Electric Generation, as Black Hills Colorado IPP has been determined to be a variable interest entity (VIE) in which the Company has a variable interest.

The following table summarizes MWh for our Power Generation segment:

Quantities Sold, Generated and Purchased (MWh) [a]	2016	2015	2014
Sold			
Black Hills Colorado IPP	1,223,949	1,133,190	1,178,464
Black Hills Wyoming [b]	644,564	663,052	581,696
Total Sold	1,868,513	1,796,242	1,760,160
Generated			
Black Hills Colorado IPP	1,223,949	1,133,190	1,178,464
Black Hills Wyoming	543,546	561,930	543,796
Total Generated	1,767,495	1,695,120	1,722,260
Purchased			
Black Hills Wyoming [b]	85,993	68,744	38,237
Total Purchased	85,993	68,744	38,237

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

(b) 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 and sells that energy to the City of Gillette.

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, and 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.

- Operating and Maintenance Services Agreement

In conjunction with the sale of the noncontrolling interest on April 14, 2016, an operating and maintenance services agreement was entered into between Black Hills Electric Generation and Black Hills Colorado IPP. This agreement sets forth the obligations and responsibilities of Black Hills Electric Generation as the operator of the generating facility owned by Black Hills Colorado IPP. This agreement is in effect from the date of the noncontrolling interest purchase and remains effective as long as the operator or one of its affiliates is responsible for managing the generating facilities in accordance with the noncontrolling interest agreement, or until termination by owner or operator.

- Shared Services Agreements

South Dakota Electric, Wyoming Electric 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.

Black Hills Colorado IPP, Wyoming Electric and South Dakota Electric are parties to a Spare Turbine Use Agreement, whereby Black Hills Colorado IPP charges South Dakota Electric and Wyoming Electric a monthly fee for the availability of a spare turbine to support the operation of Cheyenne Prairie Generating Station.

Black Hills 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, to include the EPA’s CPP, also apply to our Power Generation operations. See the discussion above under the “Environmental” and “Regulation” captions for the Electric and Gas Utilities 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 2046, without purchasing additional allowances. The EPA’s MACT rule described in the Electric and Gas Utilities section also applies 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 Electric and Gas Utilities also impact our Power Generation segment in a similar manner.

Greenhouse Gas Regulations. The EPA’s GHG Tailoring Rule described in the Electric and Gas Utilities 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.

Mining Segment

Our 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 3.8 million tons of coal in 2016.

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 typically 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, has in recent years trended upwards. The overburden ratio at December 31, 2016 was 2.07, which increased from the prior year as we continued mining in areas with higher overburden. We expect our stripping ratio to decrease to approximately 1.9 by the end of 2017 as we mine back into areas with lower overburden.

Mining rights to the coal are based on four federal leases and one state lease. The federal leases expire between April 30, 2019 and September 30, 2025 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% of the selling price of all coal. As of December 31, 2016, we estimated our recoverable coal reserves to be approximately 200 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 52 years at the current 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 Mining for further details.

Substantially all of our coal production is currently sold under contracts to:

- South Dakota Electric for use at the 90 MW Neil Simpson II plant. This contract is for the life of the plant;
- Wyoming Electric for use at the 95 MW Wygen II plant. This contract is for the life of the plant;
- The 362 MW Wyodak power plant owned 80% by PacifiCorp and 20% by South Dakota Electric. 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. South Dakota Electric is also obligated to purchase a minimum of 0.375 million tons of coal per year for its 20% share of the power plant. This contract expires at the end of December 2022;
- The 110 MW Wygen III power plant owned 52% by South Dakota Electric, 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
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Certain regional industrial customers served by truck to which we sell a total of approximately 150,000 tons of coal each year. These contracts have terms of one to five years.

Our Mining segment sells coal to South Dakota Electric and Wyoming Electric 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 Mining investment base. South Dakota Electric made a commitment to the SDPUC, the WPSC and the City of Gillette that coal for South Dakota Electric'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 Wyoming Electric 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 included a price adjustment in 2014, 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 are 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 Electric Utilities also apply to our Mining segment. Specifically, the EPA is examining plans to reduce methane emissions from coal mines as part of former President Obama's Climate Action Plan.

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.

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 expected the U.S. Office of Surface Mining (OSM) will collaborate with the EPA and propose mine backfill regulations in 2017. These regulations may increase the cost of ash disposal for the power plants and/or increase backfill costs for the coal mine.

Results of the 2016 U.S elections may have an impact on newly issued and proposed regulations and we will continue to monitor these developments.

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. In 2016, that five year permit was re-issued. Based on extensive reclamation studies, we have accrued approximately $12 million for reclamation costs as of December 31, 2016. 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. Our Oil and Gas business is focused on supporting the implementation of a planned utility Cost of Service Gas Program in partnership with our own and other utilities, while maintaining the upside value of our Piceance Basin and other assets. We are divesting non-core assets while retaining only those best suited for a Cost of Service Gas Program. In previous years, we successfully focused our efforts on proving up the potential of the Mancos formation for our Piceance Basin asset, while improving our drilling and completion practices for the Mancos. Due to sustained low oil and natural gas prices throughout 2016, Piceance Basin daily gas production was limited to meet minimum contractual gas processing obligations. We are currently assessing the Piceance Basin assets to determine their potential fit for a Cost of Service Gas Program.

As of December 31, 2016, 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 various producing basins in several states; 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 47% 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 Wyoming properties.

At December 31, 2016, we had total reserves of approximately 78 Bcfe, of which natural gas comprised 70%, crude oil comprised 17% and NGLs comprised 13%. The majority of our reserves are located in select crude oil and natural gas producing basins in the Rocky Mountain region. Approximately 10% 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 56% are located in the Piceance Basin of western Colorado, primarily in Mesa county.

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 (CG&A), 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 normally only include PUDs that are one location away from a producing well in our volume reserve estimate. However, we have no PUDs as of December 31, 2016, therefore we have not included any PUDs in our reserves estimates as of December 31, 2016. 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 21 in the Notes 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, a member of the Society of Petroleum Evaluation Engineers (SPEE), and has over 29 years of practical experience in petroleum engineering and over 27 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 Engineering Manager is the technical person primarily responsible for overseeing our third party reserve estimates. He has 30 years of experience as a petroleum engineer. He has over 23 years of experience working closely with internal and third party qualified reserve estimators in major and mid-sized oil and gas companies. He graduated from the University of Wyoming in 1986 with a Bachelor of Science degree in Petroleum Engineering.

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, 2016, 2015 and 2014:

Proved Reserves	December 31, 2016					
	Total	Piceance	San Juan	Williston	Powder River	Other
Developed Producing -						
Natural Gas (MMcf)	54,489	40,877	7,476	—	4,544	1,592
Oil (Mbbl)	2,229	16	9	—	2,189	15
NGLs (Mbbl)	1,710	419	—	—	1,092	199
Total Developed Producing (MMcfe)	78,123	43,487	7,530	—	24,230	2,876
Developed Non-Producing -						
Natural Gas (MMcf)	81	64	10	—	7	—
Oil (Mbbl)	13	—	—	—	13	—
NGLs (Mbbl)	2	—	—	—	2	—
Total Developed Non-Producing (MMcfe)	171	64	10	—	97	—
Undeveloped -						
Total Undeveloped (MMcfe)	—	—	—	—	—	—
Total MMcfe	78,294	43,551	7,540	—	24,327	2,876

Proved Reserves	December 31, 2015					
	Total	Piceance	San Juan	Williston	Powder River	Other
Developed Producing -						
Natural Gas (MMcf)	69,049	43,527	18,927	726	3,473	2,395
Oil (Mbbl)	3,415	36	5	375	2,986	13
NGLs (Mbbl)	1,619	679	—	26	863	51
Total Developed Producing (MMcfe)	99,255	47,819	18,958	3,135	26,566	2,777
Developed Non-Producing -						
Natural Gas (MMcf)	4,341	4,010	324	4	3	—
Oil (Mbbl)	19	6	—	2	11	—
NGLs (Mbbl)	134	133	—	—	1	—
Total Developed Non-Producing (MMcfe)	5,263	4,846	324	18	75	—
Undeveloped -						
Natural Gas (MMcf)	22	—	—	22	—	—
Oil (Mbbl)	14	—	—	14	—	—
NGLs (Mbbl)	—	—	—	—	—	—
Total Undeveloped (MMcfe)	106	—	—	106	—	—
Total MMcfe	104,624	52,665	19,282	3,259	26,641	2,777

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

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, 2016, 2015 and 2014:

Crude Oil	December 31, 2016					
(in Mbbl)	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	3,450	42	5	392	2,998	13
Production	(319)	(10)	(2)	(103)	(201)	(3)
Additions - acquisitions (sales)	(570)	(15)	—	(289)	(265)	(1)
Additions - extensions and discoveries	3	—	—	—	3	—
Revisions to previous estimates	(322)	(1)	6	—	(333)	6
Balance at end of year	2,242	16	9	—	2,202	15

Natural Gas	December 31, 2016					
(in MMcf)	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	73,412	47,541	19,252	751	3,475	2,393
Production	(9,430)	(5,768)	(2,736)	(177)	(220)	(529)
Additions - acquisitions (sales)	(1,291)	(68)	—	(574)	(15)	(634)
Additions - extensions and discoveries	52	52	—	—	—	—
Revisions to previous estimates [(a)]	(8,173)	(817)	(9,029)	—	1,311	362
Balance at end of year	54,570	40,940	7,487	—	4,551	1,592

Natural Gas Liquids	December 31, 2016					
(in Mbbl)	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	1,752	812	—	26	863	51
Production	(133)	(66)	—	(9)	(49)	(9)
Additions - acquisitions (sales)	(17)	—	—	(17)	—	—
Additions - extensions and discoveries	—	—	—	—	—	—
Revisions to previous estimates	110	(327)	—	—	280	157
Balance at end of year	1,712	419	—	—	1,094	199

	December 31, 2016					
Total MMcfe	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	104,624	52,665	19,282	3,259	26,641	2,777
Production	(12,142)	(6,224)	(2,748)	(849)	(1,720)	(601)
Additions - acquisitions (sales)	(4,813)	(158)	—	(2,410)	(1,605)	(640)
Additions - extensions and discoveries	70	52	—	—	18	—
Revisions to previous estimates [(a)]	(9,445)	(2,785)	(8,993)	—	993	1,340
Balance at end of year	78,294	43,550	7,541	—	24,327	2,876

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(a) Revisions to prior year estimates is primarily due to the impact of lower prices on the economics of the San Juan reserves.

Crude Oil	December 31, 2015					
(in Mbbl)	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	4,276	59	12	652	3,522	31
Production	(371)	(10)	(2)	(90)	(263)	(6)
Additions - acquisitions (sales)	(11)	—	—	—	—	(11)
Additions - extensions and discoveries	199	7	—	2	189	1
Revisions to previous estimates	(643)	(14)	(5)	(172)	(450)	(2)
Balance at end of year	3,450	42	5	392	2,998	13

Natural Gas	December 31, 2015					
(in MMcf)	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	65,440	29,565	24,533	842	4,216	6,284
Production	(10,058)	(5,715)	(3,176)	(142)	(255)	(770)
Additions - acquisitions (sales)	(828)	—	—	(1)	—	(827)
Additions - extensions and discoveries [(a)]	24,462	24,427	—	4	21	10
Revisions to previous estimates [(b)]	(5,604)	(736)	(2,105)	48	(507)	(2,304)
Balance at end of year	73,412	47,541	19,252	751	3,475	2,393

Natural Gas Liquids	December 31, 2015					
(in Mbbl)	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	1,720	592	—	25	1,007	96
Production	(102)	(33)	—	(8)	(61)	—
Additions - acquisitions (sales)	—	—	—	—	—	—
Additions - extensions and discoveries	232	232	—	—	—	—
Revisions to previous estimates	(98)	21	—	9	(83)	(45)
Balance at end of year	1,752	812	—	26	863	51

	December 31, 2015					
Total MMcfe	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	101,416	33,465	24,596	4,898	31,404	7,053
Production	(12,896)	(5,973)	(3,188)	(730)	(2,199)	(806)
Additions - acquisitions (sales)	(894)	—	—	(1)	—	(893)
Additions - extensions and discoveries (a)	27,048	25,861	—	16	1,155	16
Revisions to previous estimates (b)	(10,050)	(688)	(2,126)	(924)	(3,719)	(2,593)
Balance at end of year	104,624	52,665	19,282	3,259	26,641	2,777

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(a) Nine Mancos wells were completed and placed on production in 2015.
(b) Revisions to previous estimates were primarily driven by low commodity prices.

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 [(a)]	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

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(a) Revisions to prior year were primarily driven by commodity prices.

Production Volumes

		Year ended December 31, 2016			
Location (Basin)	Field	Oil (in Bbl)	Natural Gas (Mcfe)	NGLs (in Bbl)	Total (Mcfe)
San Juan	East Blanco	2,126	2,289,930	—	2,302,686
San Juan	All others	—	445,879	—	445,879
Piceance	Piceance	9,720	5,768,302	66,050	6,222,922
Powder River	Finn Shurley	111,789	192,030	46,659	1,142,718
Powder River	All others	89,478	27,990	2,526	580,014
Williston	Bakken	103,098	176,822	8,956	849,146
All other properties	Various	2,402	529,335	9,113	598,425
Total Volume		318,613	9,430,288	133,304	12,141,790

		Year ended December 31, 2015			
Location (Basin)	Field	Oil (in Bbl)	Natural Gas (Mcfe)	NGLs (in Bbl)	Total (Mcfe)
San Juan	East Blanco	1,753	2,698,548	—	2,709,066
San Juan	All others	—	477,710	—	477,710
Piceance	Piceance	9,977	5,713,509	32,935	5,970,981
Powder River	Finn Shurley	172,235	255,482	60,671	1,652,918
Powder River	All others	91,402	—	—	548,412
Williston	Bakken	90,469	142,091	7,903	732,323
All other properties	Various	5,657	770,038	175	805,030
Total Volume		371,493	10,057,378	101,684	12,896,440

		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

Other Information

	As of December 31, 2016	As of December 31, 2015
Proved developed reserves as a percentage of total proved reserves on an MMcfe basis	100 %	100 %
Proved undeveloped reserves as a percentage of total proved reserves on an MMcfe basis	— %	— %
Present value of estimated future net revenues, before tax, discounted at 10% (in thousands)	$40,611	$85,711

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

	December 31, 2016					
	Total	Piceance	San Juan	Williston	Powder River	Other
Gas per Mcf[(a)]	$2.25	$ 2.32	$2.34	$ —	$1.30	$2.58
Oil per Bbl	$37.35	$ 33.80	$27.26	$ —	$37.41	$38.61
NGL per Bbl	$11.92	$ 15.08	$—	$ —	$9.83	$16.72

	December 31, 2015					
	Total	Piceance	San Juan	Williston	Powder River	Other
Gas per Mcf	$1.27	$ 1.14	$1.49	$ 1.82	$1.35	$1.82
Oil per Bbl	$44.72	$ 43.86	$43.15	$ 44.01	$44.81	$48.00
NGL per Bbl	$18.96	$ 22.58	$—	$ 22.24	$15.15	$23.92

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	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

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(a) For reserves purposes, costs to gather gas previously netted from the gas price were reclassified into operating expenses in 2016, with approximate rates of $1.54/Mcf for Piceance, $0.92/Mcf for San Juan and $0.53/Mcf for all others. For accounting purposes, consistent with prior years, the sales price for natural gas is adjusted for transportation costs and other related deductions when applicable, as further described in Note 1 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Drilling Activity

In 2016, we participated in drilling 17 gross (0.10 net) and completing 22 gross (0.44 net) development wells that were sold effective July 1, 2016, and therefore, have not been included in the drilling statistics table below. 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. As of December 31, 2016, we have 4 wells in the Piceance Basin that have been drilled but not completed. The well completions have been deferred indefinitely.

The following tables reflect wells completed through our drilling activities for the last three years that were included in the annual reserves.

Year ended December 31,	2016		2015		2014	
Net Development Wells	Productive	Dry	Productive	Dry	Productive	Dry
Williston	—	—	0.09	—	0.26	—
Powder River	—	—	1.00	—	—	—
Total net development wells	—	—	1.09	—	0.26	—

Year ended December 31,	2016		2015		2014	
Net Exploratory Wells	Productive	Dry	Productive	Dry	Productive	Dry
Piceance	—	—	7.03	—	1.17	—
Powder River	—	—	0.60	2.00	3.00	—
Total net exploratory wells	—	—	7.63	2.00	4.17	—

Recompletion Activity

Recompletion activities for the years ended December 31, 2016, 2015 and 2014 were insignificant to our overall oil and gas operations.

Productive Wells

The following table summarizes our gross and net productive wells at December 31, 2016, 2015 and 2014:

	December 31, 2016					
	Total	Piceance	San Juan	Williston	Powder River	Other (a)
Gross Productive:						
Crude Oil	398	1	1	—	391	5
Natural Gas	315	59	142	—	8	106
Total	713	60	143	—	399	111
Net Productive:						
Crude Oil	282.87	—	0.96	—	281.26	0.65
Natural Gas	191.79	47.44	129.13	—	0.16	15.06
Total	474.66	47.44	130.09	—	281.42	15.71

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

	December 31, 2015					
	Total	Piceance	San Juan	Williston	Powder River	Other (a)
Gross Productive:						
Crude Oil	532	2	1	102	422	5
Natural Gas	474	60	150	—	9	255
Total	1,006	62	151	102	431	260
Net Productive:						
Crude Oil	299.13	0.15	0.96	3.29	294.09	0.64
Natural Gas	208.92	49.81	136.92	—	0.21	21.98
Total	508.05	49.96	137.88	3.29	294.30	22.62

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

	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

(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, 2016:

	Undeveloped		Developed		Total	
	Gross	Net [(a)]	Gross	Net	Gross	Net
Piceance	32,997	22,177	68,151	55,906	101,148	78,083
San Juan	27,027	27,138	24,936	23,672	51,963	50,810
Powder River	101,750	75,449	22,600	14,715	124,350	90,164
Montana	160	20	480	60	640	80
Other	14,766	3,135	25,226	4,689	39,992	7,824
Total	176,700	127,919	141,393	99,042	318,093	226,961

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(a) Approximately 3% (14,081 gross and 3,406 net acres), 3% (22,834 gross and 4,405 net acres) and 7% (56,265 gross and 9,211 net acres) of our undeveloped acreage could expire in 2017, 2018 and 2019, 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.

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. In 2014, our delivery of production did not meet the minimum requirement, and in 2015, we did not meet the minimum requirements of this contract until mid-February. We have excess production capacity from wells completed in 2015, and we have four additional wells which have not yet been completed, therefore do not foresee any challenges in our ability to meet this commitment.

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 BLM, 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 or use, 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 approximately 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 fracture 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’s BLM re-proposed rules regulating the use of hydraulic fracturing on Federal and Indian Lands. BLM issued the final rule March 20, 2015. Subsequently on September 30, 2015, the U.S. District Court for the District of Wyoming issued a preliminary injunction preventing the BLM from enforcing the final rule on federal and Indian lands. Regardless of the rule status, we already employ these practices in our hydraulic fracturing operations as described below, and if this rule should be re-issued, it will have minimal impact on our operations. 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) effective January 2015.

In 2013, we participated in the State of Colorado's stakeholder process to incorporate EPA Quad O requirements into state regulation. Colorado 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 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 typically 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. On October 22, 2015, the EPA expanded coverage to gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines. The first annual reports of emissions calculated using these new requirements are due to the EPA by March 31, 2017 to cover 2016 emissions. We are currently expanding our inventory system to accommodate these new requirements. 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, on September 18, 2015, the EPA proposed standards for methane and VOC emissions from new and modified oil and gas production sources and natural gas processing and transmission sources. The rule was finalized May 12, 2016 and includes provisions for clarifying permitting requirements for determination of major/minor source status. Future site developments may incur permitting delays if required aggregation of adjacent operations results in a major source air permit requirement. Additionally, EPA plans to work with industry and states to reduce methane from existing oil and gas operations and is exploring regulatory opportunities for applying remote sensing technologies to further improve the identification and quantification of methane and VOC emissions. In 2016 the EPA sent out Information Collection Requests to owners of oil and gas operations to support this rule development. We have received these requests and are in the process of submitting the required data.

On November 18, 2016, the Department of Interior's BLM finalized their Venting and Flaring Rule (Methane Rule), targeting reduction or elimination of venting, flaring and leaks of natural gas at new and existing oil and gas wells on public lands. This rule will result in additional monitoring costs at our Colorado, New Mexico and Wyoming operations. On November 18, 2016, the Wyoming and Montana Attorneys General filed a petition for review of this rule with the United States District Court for the District of Wyoming. The District Court did not issue a stay pending litigation outcome and this rule went into effect January 17, 2017.

Ozone Regulations. In 2015, the EPA developed 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, finalized October 26, 2015 are not expected to impact our current operations. However, the new regulations are very close to background levels, the ozone concentration level that the average person is exposed to, and may have an impact on future development.

Other Properties

In addition to the facilities previously disclosed in Items 1 and 2, 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 Rapid City, South Dakota, we have a new 220,000 square foot corporate headquarters building under construction. Construction is expected to be completed in the fourth quarter of 2017.

- 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 an operations center with approximately 25,000 square feet, and in Casper Wyoming, we own an 18,000 square foot distribution center.

- In Papillion, Nebraska, we own an office building consisting of approximately 36,600 square feet; in Albion, Nebraska, we own an operations center with approximately 26,000 square feet; and in Kearney, Nebraska, we own an operations center with approximately 21,000 square feet.

- In Fayetteville, Arkansas, we own an operations center with approximately 36,000 square feet.

- In Arkansas, Nebraska, Iowa, Colorado, Kansas and Wyoming we own various office, service center, storage, shop and warehouse space totaling over 666,000 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 117,000 square feet utilized by our Electric Utilities and 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 and 9,100 square feet of office space in Rapid City, South Dakota;

- Approximately 37,600 square feet for a customer call and operations center in Lincoln, Nebraska, and approximately 12,000 square feet for an operations center in Norfolk, Nebraska;

- Approximately 47,400 square feet of office space in Denver, Colorado, of which we sublease approximately 10,100 square feet to a third party, and approximately 27,000 square feet of office space in Golden, Colorado, which is the former SourceGas Corporate headquarters;

- Approximately 35,000 square feet for office space and customer call center in Fayetteville, Arkansas;

- Approximately 204,000 square feet of various office, service center and warehouse space leased by the Gas Utilities; and

- Other offices and warehouse facilities located within our service areas.

Substantially all of the tangible utility properties of South Dakota Electric and Wyoming Electric are subject to liens securing first mortgage bonds issued by South Dakota Electric and Wyoming Electric, respectively.

Employees

At December 31, 2016, we had 2,834 full-time employees. Approximately 27% of our employees are represented by a collective bargaining agreement. We have not experienced any labor stoppages in recent years. At December 31, 2016, approximately 27% of our Electric Utilities and Gas Utilities employees were eligible for regular or early retirement.

The following table sets forth the number of employees:

	Number of Employees
Corporate	496
Electric Utilities and Gas Utilities	2,213
Mining, Power Generation and Oil and Gas	125
Total	2,834

At December 31, 2016, certain of our employees of our Electric Utilities and Gas Utilities were covered by the following collective bargaining agreements:

Utility	Number of Employees	Union Affiliation	Expiration Date of Collective Bargaining Agreement
South Dakota Electric [(a)]	132	IBEW Local 1250	March 31, 2017
Wyoming Electric	48	IBEW Local 111	June 30, 2019
Colorado Electric	107	IBEW Local 667	April 15, 2018
Iowa Gas	111	IBEW Local 204	July 31, 2020
Kansas Gas	19	Communications Workers of America, AFL-CIO Local 6407	December 31, 2019
Nebraska Gas [(b)]	109	IBEW Local 244	March 13, 2017
Nebraska Gas [(c)]	144	CWA Local 7476	October 30, 2019
Wyoming Gas [(c)]	83	CWA Local 7476	October 30, 2019
Total	753		

(a) On January 26, 2017, South Dakota Electric’s contract was ratified with an expiration date of March 31, 2022.

(b) Negotiations for Nebraska Gas started in January 2017, with an expected ratification in March 2017. We do not anticipate any issues with the ratification.

(c) In the 2016 negotiations with the CWA 7476, the union agreed to disclaim their interest in Colorado Gas employees and to split the remaining bargaining unit into two distinct bargaining units, Nebraska Gas and Wyoming Gas.

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;

- 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 or our power 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.

The SourceGas Transaction may not achieve its intended results, including anticipated operating efficiencies and cost savings, which may adversely affect our business, financial condition or results of operations.

While management expects that the SourceGas Transaction will result in various benefits, including a significant amount of operating efficiencies and other financial and operational benefits, there can be no assurance regarding when or the extent to which we will be able to realize these operating efficiencies or other benefits. Events outside of our control, including but not limited to regulatory changes or developments, could also adversely affect our ability to realize the anticipated benefits from the transaction.

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. Our utilities purchase 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 our utilities' ability to operate their facilities;
- Breakdown or failure of equipment or processes, including those operated by PacifiCorp at the Wyodak plant;
- Our ability to transition and replace our retirement-eligible utility employees. At December 31, 2016, approximately 27% of our Electric Utilities and Gas Utilities employees were eligible for regular or early retirement;
- 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 service facilities and equipment. Natural conditions and other disasters such as wind, lightning and winter storms can cause wildfires, pole failures and associated property damage and outages;
- 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 27% of our employees are represented by a total of seven 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. Demand for natural gas 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 results of operations, financial condition and cash flows.

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 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.

While our planned activity related to our Oil and Gas segment is limited, weather conditions can also limit or temporarily halt our drilling, completion and producing activities at our crude oil and natural gas operations. Primarily in the winter and spring, our operations can be curtailed because of cold, snow and wet conditions, and severe weather could exacerbate these operational issues. In addition, weather conditions and other events could temporarily impair our ability to transport our crude oil and natural gas production.

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 not only reduces revenues and profits, but also reduces the quantity and value 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, which has driven prices down in recent years. There is also risk that increased domestic resources could drive both crude oil and natural gas 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.

Our revenues, results of operations and financial condition are impacted by customer growth and usage in our service territories and may fluctuate with current economic conditions, emerging technologies or responses to price increases.

Our revenues, results of operations and financial condition are impacted by demand in our service territories. Customer growth and usage may be impacted by a number of factors, including: the voluntary reduction of consumption of electricity and natural gas by our customers in response to increases in prices and demand-side management programs, economic conditions impacting decreases in customers' disposable income and the use of distributed generation resources or other emerging technologies. Continued technological improvements may make customer and third-party distributed generation and energy storage systems, including fuel cells, micro-turbines, wind turbines, solar cells and batteries, more cost effective and feasible for our customers. If more customers utilize their own generation, demand for energy from us would decline. Such developments could affect the price of energy and delivery of energy, require further improvements to our distribution systems to address changing load demands and could make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. Each of these factors could materially affect our results of operations, financial position and cash flows.

Our operations rely on storage and transportation assets owned by third parties to satisfy our obligations.

Our Electric Utilities, Gas Utilities 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.

Our utilities are subject to pipeline safety and system integrity laws and regulations that may require significant capital expenditures or significant increases in operating costs.

Compliance with pipeline safety and system integrity laws and regulations, or future changes in these laws and regulations, may result in increased capital, operating and other costs which may not be recoverable in a timely manner from customers in rates. Failure to comply may result in fines, penalties, or injunctive measures that would not be recoverable from customers in rates and could result in a material impact on our financial results.

Our energy production, transmission and distribution activities, and our storage facilities for our natural gas involve numerous risks that may result in accidents and other catastrophic events that could give rise to additional costs and cause a substantial loss to us.

Inherent in our natural gas and electricity transmission and distribution activities, as well as in our production, transportation and storage of crude oil and natural gas and our Mining operations, are a variety of hazards and operating risks, such as leaks, blowouts, fires, releases of hazardous materials, explosions and operational problems. These events could impact the safety of employees or others and result in injury or loss of human life, and cause significant damage to property or natural resources (including public lands), environmental pollution, impairment of our operations and substantial financial losses to us. 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 substantial. While we maintain liability and property insurance coverage, such policies are subject to certain limits and deductibles. The occurrence of any of these events not fully covered by our insurance could have a material adverse effect on our financial position, results of operations or cash flows.

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.

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

We use and operate 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, including certain safeguards required by FERC. 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, NERC, CFTC, EPA, OSHA, SEC and MSHA may impose significant civil and criminal penalties to enforce compliance requirements relative to our business, which 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.

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.

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 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 $1.3 billion of goodwill on our consolidated balance sheets as of December 31, 2016. A substantial portion of the goodwill is related to the SourceGas Acquisition and 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.

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.

We conduct surface mining operations that are subject to operations, reclamation and closure standards. 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, and any inaccuracies in interpretation or modeling could materially affect the estimated quantity and quality of our reserves.

The process of estimating coal reserves is uncertain and requires interpretations and modeling. 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

Our inability to successfully include our Oil and Gas segment core assets in utility Cost of Service Gas Programs may result in additional material impairments of our Oil and Gas assets.

In our oil and gas business, we are actively divesting non-core assets while retaining those assets best suited for a Cost of Service Gas Program for our utilities and third-party utilities, and have refocused our professional staff on assisting with the implementation of a Cost of Service Gas Program. The implementation of Cost of Service Gas Programs will provide a long-term physical hedge for a portion of a utility’s gas supply, enhancing the quality of the overall gas supply portfolio. In addition to providing utility customers the potential benefits associated with more predictable and lower long-term natural gas prices, it also provides utilities an opportunity to increase earnings through investment in gas reserves. Cost of Service Gas Programs require regulatory approval from state commissions that regulate utility participants in these programs. Failure to obtain these approvals may result in additional impairments of our Oil and Gas assets, and could adversely affect the market perception of our business, operating results and stock price.

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.

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 variances in interpretations or assumptions could materially affect the estimated quantities and present value of our reserves. Actual prices, production, development expenditures, operating expenses and quantities of recoverable crude oil and natural gas reserves may vary significantly from those assumed in our estimates. 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 that could adversely affect our results of operations.

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 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.

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.

While our planned activity related to our Oil and Gas segment is limited, drilling activities are subject to many risks, including the risk that no commercially productive oil or gas reservoirs will be encountered. 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. Lack of drilling success could have a material adverse effect on our financial condition and results of operations.

We could incur additional 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, which 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. Two primary factors in the ceiling test are natural gas and crude oil reserve quantities, which are impacted by current commodity prices, and SEC-defined crude oil and gas prices, both of which impact the present value of estimated future net revenues. We recorded non-cash impairment charges in 2016 and 2015 due to the full cost ceiling limitations. See Note 13 of 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 Baa2 (Stable outlook) by Moody's; BBB (Stable outlook) by S&P; and BBB+ (Negative 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.

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 our exchange-traded futures contracts are subject to futures margin posting requirements, which 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.

As discussed in Note 18 of the Consolidated Financial Statements in this Annual Report on Form 10-K, we have one defined benefit pension plan and several defined post-retirement healthcare plans and non-qualified retirement 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.

As 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, equity or debt service funds.

There is no assurance as to the amount, if any, 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 financing on reasonable terms needed to refinance debt, fund planned capital expenditures or otherwise execute our operating strategy.

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 from 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 of gas in pipelines.

While we maintain insurance coverage for our operated wells and we participate in insurance coverage maintained by the operators of our wells, 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. Significant regulatory developments have, and likely will continue to, require changes to our current employee benefit plans and in our administrative and accounting processes, as well as changes to the cost of our plans, and the increasing costs and funding requirements associated with our health care plans may adversely affect our results of operations, financial position or liquidity.

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.

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

Prior to the Acquisition, SourceGas was a private company, exempt from reporting and control requirements under Section 404 of the Sarbanes-Oxley Act of 2002. As permitted by the guidance set forth by the Securities and Exchange Commission, the acquired SourceGas businesses are not included in management's assessment of internal control over financial reporting for the year ended December 31, 2016. 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.

A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system's objectives will be met. While we expect our control system to adequately integrate the SourceGas processes, we cannot be certain that our current design for internal control over financial reporting, or any additional changes to be made, will be sufficient to enable management to determine that our internal controls are effective for any period, or on an ongoing basis. If we are unable to assert that our internal controls over financial reporting are effective, market perception of our business, operating results and stock price could be adversely affected.

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 may 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.”

The GHG Tailoring Rule, effective June 2010, 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, published October 2015, effectively prohibits new coal-fired units until carbon capture and sequestration becomes technically and economically feasible.

On October 23, 2015, the EPA finalized the CPP to cut carbon emissions from existing electric generating units. The design of the CPP is to decrease existing coal-fired generation, increase the utilization of existing gas generation, increase renewable energy and demand side management. The rule, which does not propose to regulate individual emission sources, calls for each state to develop plans to meet the EPA-assigned statewide average emission rate target for that state 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. The U.S. Supreme Court entered an order staying the CPP in February 2016, pending appeal. The effect of the order is to delay the CPP’s compliance deadlines until challenges to the CPP have been fully litigated and the U.S. Supreme Court has ruled. In 2015 and again in 2016, we met with the staff of state air programs and public utility commissions on several occasions. We will continue to work closely with state regulatory staff as these plans develop.

Due to uncertainty as to the final outcome of federal climate change legislation, legal challenges, state clean power plan developments 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.

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, the closure or reduction of load of coal generating facilities and potential increased load of our combined cycle natural gas fired units. 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 costs to achieve or maintain compliance with existing or future governmental laws, regulations or requirements, and any failure to do so, could 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 operations and financial condition. Environmental compliance expenditures could be substantial in the future if the trend towards stricter standards, greater regulation, more extensive permitting requirements and an increase in the number of assets we operate continues.

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.

Future regulations may require further reductions in emissions of mercury, hazardous pollutants, SO_2, NO_x, volatile organic compounds, particulate matter and GHG, which are released into the air when coal is burned. These requirements could require the installation of costly emission control technology or the implementation of other measures. Reductions in mercury emissions required by EPA’s MATS rule described earlier, 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. The EPA’s October 23, 2015 CPP described earlier, which has been stayed pending appeal, is designed to reduce carbon emissions from existing electric generating units. The basis of the CPP is to decrease existing coal-fired generation, increase the utilization of existing gas fired combined cycle 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.

Coal competes with other energy sources, such as natural gas, wind, solar and hydropower. The CPP regulation is expected to have an adverse effect on coal as a domestic energy source, and could have a significant impact on our 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 19, “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, 2016, we had 3,860 common shareholders of record and approximately 28,000 beneficial owners, representing all 50 states, the District of Columbia and 8 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 25, 2017 meeting, our Board of Directors declared a quarterly dividend of $0.445 per share, equivalent to an annual dividend of $1.78 per share, marking 2017 as the 47th 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, 2016	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$ 0.420	$ 0.420	$ 0.420	$ 0.420
Common stock prices				
High	$ 61.13	$ 63.53	$ 64.58	$ 62.83
Low	$ 44.65	$ 56.16	$ 56.86	$ 54.76

Year ended December 31, 2015	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$ 0.405	$ 0.405	$ 0.405	$ 0.405
Common stock prices				
High	$ 53.37	$ 52.96	$ 47.27	$ 47.51
Low	$ 47.88	$ 43.48	$ 36.81	$ 40.00

UNREGISTERED SECURITIES ISSUED

There were no unregistered securities sold during 2016.

ISSUER PURCHASES OF EQUITY SECURITIES

There were no equity securities acquired for the three months ended

December
31, 2016.

ITEM 6. SELECTED FINANCIAL DATA

(Minor differences may result due to rounding)

Years Ended December 31, (dollars in thousands, except per share amounts)	2016	2015	2014	2013	2012
Total Assets	$6,515,444	$4,626,643	$4,222,301	$3,820,877	$3,677,019
Property, Plant and Equipment					
Total property, plant and equipment	$6,412,223	$4,976,778	$4,563,400	$4,259,445	$3,930,772
Accumulated depreciation and depletion	(1,943,234)	(1,717,684)	(1,357,929)	(1,306,390)	(1,229,159)
Total property, plant and equipment, net	$4,468,989	$3,259,094	$3,205,471	$2,953,055	$2,701,613
Capital Expenditures	$467,119	$458,821	$391,267	$379,534	$347,980
Capitalization (excluding noncontrolling interests)					
Current maturities of long-term debt	$5,743	$—	$275,000	$—	$103,973
Notes payable	96,600	76,800	75,000	82,500	277,000
Long-term debt, net of current maturities and deferred financing costs	3,211,189 (a)	1,853,682 (a)	1,255,953	1,383,714	927,561
Common stock equity	1,614,639 (b)	1,465,867 (b)	1,353,884	1,283,500	1,205,800
Total capitalization	$4,928,171	$3,396,349	$2,959,837	$2,749,714	$2,514,334
Capitalization Ratios					
Short-term debt, including current maturities	2 %	2 %	12 %	3 %	15 %
Long-term debt, net of current maturities	65 % (a)	55 %	42 %	50 %	37 %
Common stock equity	33 %	43 %	46 %	47 %	48 %
Total	100 %	100 %	100 %	100 %	100 %
Total Operating Revenues	$1,572,974	$1,304,605	$1,393,570	$1,275,852	$1,173,884
Net Income Available for Common Stock					
Electric Utilities	$85,827	$77,579 (g)	$57,270 (g)	$49,003 (g)	$52,123 (g)
Gas Utilities	59,624	39,306 (g)	44,151 (g)	35,838 (g)	27,465 (g)
Power Generation	25,930 (c)	32,650	28,516	16,288 (c)	21,328
Mining	10,053	11,870	10,452	6,327	5,626
Oil and Gas	(71,054) (b)	(179,958) (b)	(8,525)	(1,751)	18,683 (b)
Corporate and intersegment eliminations	(37,410) (d)	(13,558) (d, g)	(975)	12,602 (d)	(15,808) (d)
Net Income (loss) available for common stock before	72,970	(32,111)	130,889	118,307	109,417

discontinued operations					
Income (loss) from discontinued operations, net of tax [e]	—	—	—	(884)	(6,977)
Net income (loss) available for common stock	$72,970	$(32,111)	$130,889	$117,423	$102,440

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SELECTED FINANCIAL DATA continued

Years Ended December 31, (dollars in thousands, except per share amounts)	2016	2015	2014	2013	2012
Dividends Paid on Common Stock	$87,570	$72,604	$69,636	$67,587	$65,262
Common Stock Data[f] (in thousands)					
Shares outstanding, average basic	51,922	45,288	44,394	44,163	43,820
Shares outstanding, average diluted	53,271	45,288	44,598	44,419	44,073
Shares outstanding, end of year	53,382	51,192	44,672	44,499	44,206
Earnings (Loss) Per Share of Common Stock (in dollars)					
Basic earnings (loss) per average share -					
Continuing operations	$1.59	$(0.71)	$2.95	$2.68	$2.50
Discontinued operations [e]	—	—	—	(0.02)	(0.16)
Non-controlling interest	(0.19)	—	—	—	—
Total	$1.41	$(0.71)	$2.95	$2.66	$2.34
Diluted earnings (loss) per average share -					
Continuing operations	$1.55	$(0.71)	$2.93	$2.66	$2.48
Discontinued operations	—	—	—	(0.02)	(0.16)
Non-controlling interest	(0.18)	—	—	—	—
Total	$1.37	$(0.71)	$2.93	$2.64	$2.32
Dividends Declared per Share	$1.68	$1.62	$1.56	$1.52	$1.48
Book Value Per Share, End of Year	$30.25	$28.63	$30.31	$28.84	$27.28
Return on Average Common Stock Equity (full year)	4.7%	(2.3)%	9.9%	9.4%	8.7%

SELECTED FINANCIAL DATA continued

Years ended December 31,	2016	2015	2014	2013	2012
Operating Statistics:					
Generating capacity (MW):					
Electric Utilities (owned generation)	941	841	841	790	859
Electric Utilities (purchased capacity)	110	210	210	150	150
Power Generation (owned generation)	269	269	269	309	309
Total generating capacity	1,320	1,320	1,320	1,249	1,318
Electric Utilities:					
MWh sold:					
Retail electric	5,140,519	4,990,594	4,775,808	4,642,254	4,598,080
Contracted wholesale	246,630	260,893	340,871	357,193	340,036
Wholesale off-system	769,843	1,000,085	1,118,641	1,456,762	1,652,949
Total MWh sold	6,156,992	6,251,572	6,235,320	6,456,209	6,591,065
Gas Utilities:					
Gas sold (Dth)	79,165,742	56,638,299	64,861,411	64,131,850	51,620,293
Transport volumes (Dth)	126,927,565	77,393,775	77,433,266	73,730,017	71,092,286
Power Generation Segment:					
MWh Sold	1,868,513	1,796,242	1,760,160	1,564,789	1,304,637
MWh Purchased	85,993	68,744	38,237	5,481	8,011
Oil and Gas Segment:					
Oil and gas production sold (MMcfe)	12,142	12,896	9,986	9,529	12,544
Oil and gas reserves (MMcfe) [(b)]	78,294	104,624	101,416	86,713	80,683
Mining Segment:					
Tons of coal sold (thousands of tons)	3,817	4,140	4,317	4,285	4,246
Coal reserves (thousands of tons)	199,905	203,849	208,231	212,595	232,265

(a) 2016 includes the debt associated with the SourceGas acquisition (see Note 6 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K).

(b) 2016 includes non-cash after-tax impairment charges to our crude oil and natural gas properties of $67 million. 2015 includes non-cash after-tax ceiling test impairment charges to our crude oil and natural gas properties of $158 million and a non-cash after-tax equity investment impairment charge of $2.9 million (see Note 13 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K). 2012 includes a non-cash after-tax ceiling test impairment charge to our crude oil and natural gas properties of $32 million offset by an after-tax gain on sale of $49 million related to our Williston Basin assets.

(c) On April 14, 2016, BHEG sold a 49.9% interest in Black Hills Colorado IPP. Net income available for common stock for 2016 was reduced by $9.6 million attributable to this noncontrolling interest. 2013 includes $6.6 million after-tax expense relating to the settlement of interest rate swaps and write-off of deferred financing costs in conjunction with the prepayment of Black Hills Wyoming's project financing.

(d) 2016 and 2015 include incremental SourceGas Acquisition costs, after-tax of $30 million and $6.7 million, respectively. 2016 and 2015 also include after-tax internal labor costs attributable to the SourceGas Acquisition of $9.1 million and $3.0 million that otherwise would have been charged to other segments. 2013 and 2012 include $20 million and $1.2 million non-cash after-tax unrealized mark-to-market gains, 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.

(e) Discontinued operations in 2013 and 2012 include post-closing adjustments and operations relating to Enserco, sold in 2012.

(f) In 2016, we issued 1.97 million shares at an average share price of $60.95 under our ATM equity offering program. In November 2015, we issued 6.3 million shares of common stock, par value $1.00 per share at a price of $40.25.

(g) Effective January 1, 2016, Cheyenne Light's natural gas utility results are reported in our Gas Utilities segment. Cheyenne Light's gas utility results have been reclassified from the Electric Utilities segment to the Gas Utilities segment in the amounts of $1.7 million, $2.3 million, $3.1 million and $0.5 million for the years ending December 31, 2015, 2014, 2013 and 2012 respectively. Due to this reclassification, there also exists an intersegment elimination of $0.2 million that has been moved to "Corporate and intersegment eliminations" for the period ended December 31, 2015.

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 5 of the Consolidated Financial Statements in this Annual Report on Form 10-K.

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

We are a customer-focused, growth-oriented, vertically-integrated utility company operating in the United States. We report our operations and results in the following financial segments.

Electric Utilities: Our Electric Utilities segment generates, transmits and distributes electricity to approximately 208,500 customers in South Dakota, Wyoming, Colorado and Montana. 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.

Gas Utilities: Our Gas Utilities conduct natural gas utility operations through our Arkansas, Colorado, Iowa, Kansas, Wyoming and Nebraska subsidiaries. Our Gas Utilities distribute and transport natural gas through our network to approximately 1,030,800 natural gas 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 Black Hills Energy Services. Black Hills Energy Services provides approximately 55,000 retail distribution customers in Nebraska and Wyoming with unbundled natural gas commodity offerings under the regulatory-approved Choice Gas Program. We also sell, install and service air, heating and water-heating equipment, and provide associated repair service and protection plans under various trade names. Service Guard and CAPP primarily provide appliance repair services to approximately 61,000 and 33,000 residential customers, respectively, 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 and maintaining customer-owned gas infrastructure facilities, typically through one-time contracts.

Power Generation: Our Power Generation segment produces electric power from its generating plants and sells the electric capacity and energy principally to our utilities under long-term contracts.

Mining: Our Mining segment produces coal at our coal mine near Gillette, Wyoming and sells the coal primarily to on-site, mine-mouth power generation facilities.

Oil and Gas: Our Oil and Gas segment engages in the production of crude oil and natural gas, primarily in the Rocky Mountain region. We are divesting non-core oil and gas assets while retaining those best suited for a cost of service gas program, and we have refocused our professional staff on assisting utilities with the implementation of cost of service gas programs.

Our reportable segments are based on our method of internal reporting, which is generally segregated by differences in products, services and regulation. All of our operations and assets are located within the United States. Prior to March 31, 2016, our segments were reported within two business groups, our Utilities Group, containing the Electric Utilities and Gas Utilities segments, and our Non-regulated Energy Group, containing the Power Generation, Mining and Oil and Gas segments. We have continued to report our operations consistently through our reportable segments. However, we will no longer separate the segments by business group. We are a customer-focused, growth-oriented, vertically-integrated utility company. All of our non-utility business segments support our utilities, with the exception of our Oil and Gas segment.

Segment reporting transition of Cheyenne Light's Natural Gas distribution

Effective January 1, 2016, the natural gas operations of Cheyenne Light are reported in our Gas Utilities Segment. Through December 31, 2015, Cheyenne Light's natural gas operations were included in our Electric Utilities Segment as these natural gas operations were consolidated within Cheyenne Light since its acquisition. This change is a result of our business segment reorganization to, among other things, integrate all regulated natural gas operations, including the SourceGas Acquisition, into our Gas Utilities Segment which is led by the Group Vice President, Natural Gas Utilities. Likewise, all regulated electric utility operations including Cheyenne Light's electric utility operations are reported in our Electric Utilities Segment, which is led by the Group Vice President, Electric Utilities. The prior periods have been reclassified to reflect this change in presentation between the Electric Utilities and Gas Utilities segments. The reclassifications moving Cheyenne Light's natural gas results from the Electric Utilities segment to the Gas Utilities segment consisted of increasing Gas Utilities and decreasing Electric Utilities Revenue, Gross Margin and Net Income (loss) by $44 million, $22 million and $1.7 million, and $40 million, $17 million and $2.3 million for the Years ended December 31, 2015 and December 31, 2014, respectively.

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 utility supporting non-regulated energy businesses, primarily by increasing our customer base and providing superior service.

SourceGas Acquisition

On February 12, 2016, Black Hills Utility Holdings acquired SourceGas Holdings, LLC from investment funds managed by Alinda Capital Partners and GE Energy Financial Services, a unit of General Electric Co., pursuant to the purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, which included the assumption of $760 million in debt at closing. The acquisition is in alignment with our strategy to invest in utilities and to expand utility operations consistent with our regional focus and strategic advantages as further discussed below in our business strategies. See additional information below under Prospective Information and in Note 2 of the Notes to Consolidated Financial Statements in Item 8 of this Annual Report on Form 10-K.

Our Objective

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 2016 include:

- Our three electric utilities achieved 1st quartile reliability ranking with 64 customer minutes of outage time (SAIDI) in 2016 compared to industry averages (IEEE 2016 1st quartile is less than 81 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 3.27% for coal fired plants, 0.76% for natural gas plants, and 0.00% for diesel plants in 2016, compared to an industry average* of 4.61%, 4.41%, and 2.18%, respectively (*NERC GADS 2015 Data);

- Our power generation fleet availability was 94.41% for coal fired plants, 96.56% for natural gas fired plants, 98.92% for diesel fired plants, and 99.20% for wind generation in 2016 while the industry averages** were 85.29%, 89.65%, 94.59% respectively (**NERC GADS 2015 data was used for coal, natural gas and diesel; data is not currently kept for wind);

- Our safety TCIR of 1.7 compares well to an industry average of 2.2+ and our DART rate of 0.6 compares to an industry average of 1.2+ (+ Bureau of Labor Statistics (BLS)-all utilities of all sizes - most recent industry averages are 2015);

- Our OSHA TCIR rate during construction of our generating facilities is also significantly better than industry average with a TCIR rate of 3.1 during the 2016 construction of the Pueblo LM 6000 compared to an industry average of 4.4 for natural-gas fired plants.

- Our mine completed five 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 seven years without a lost time accident. The mine also received the State Mine Inspector's Award for the third year in a row for operating as the safest small mine and received the Mine Safety and Health Administration's Certificate of Achievement for No Lost Time Incidents.

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 to 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 just under 10%. The average regulatory lag is less than 12 months, according to the Edison Electric Institute. Sustained low interest rates heavily influence 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 for these commodities. The increased worldwide supply of crude oil and natural gas caused prices to continue to decline throughout 2016, making drilling and exploration activities uneconomical in many producing basins. We continued to focus our oil and gas expertise to support cost of service gas programs for our own utilities and third-party utilities.

Currently, approximately 30% 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 regulatory climate in recent years, 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 believe 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, low per unit operation and maintenance costs and high levels of plant availability. 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 were exemplified in our successful requests to secure the construction financing riders in both Wyoming and South Dakota during the 2013-2014 construction of Cheyenne Prairie, and in Colorado with the 2016 completion of a 40 MW natural gas-fired combustion turbine and Peak View Wind Project. These riders reduce the total cost of the plant ultimately passed along to our customers while we construct these plants to accommodate growth and replace plants that were closed prematurely due to environmental regulations.

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 uncertainty, and also potential investment opportunities, 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 investment opportunities, either for our electric utilities or for our power generation business. These mandates will also most likely increase prices for electricity and/or natural gas for our utility customers. As a regulated utility we are responsible for providing safe, reasonably priced and 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 utilities 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 Farm, a 29 MW wind farm project, was completed in the fourth quarter of 2012, as part of our plan to meet Colorado's Renewable Energy Standard. We had also previously submitted requests for additional renewable energy supplies in 2014 for our Colorado Electric utility to help meet the renewable mandate. On October 21, 2015, we received approval from the Colorado Public Utilities Commission to purchase the $109 million, 60 MW Peak View Wind Project, under the terms of a build/transfer agreement with a third party developer. This wind project commenced commercial operation in November 2016;
- 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 or other standards, such as those

established by the CPP. For example, under two 20-year power purchase agreements, we purchase a total of 60 MW of energy from wind farms located near Cheyenne, Wyoming, for use at our South Dakota Electric and Wyoming Electric subsidiaries; 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.

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Maintain a safe and reliable gas distribution system. We are in compliance with all applicable federal, state and local regulations as well as many industry best practices. Any leaks discovered, whatever the cause, are repaired as soon as possible while ensuring the safety of the public and our employees. We construct and renew our piping systems with state of the art materials and products to safely and efficiently deliver natural gas to our customers. Maintaining our product within our piping systems is of utmost importance to ensure the safety of the public and our employees and to protect the environment. To that end, we monitor the integrity of our piping systems and renew as appropriate to accomplish the stated goals of safe, efficient energy delivery. We have removed all cast and wrought iron from our system. With respect to unprotected steel, our distribution system contains less than 2.57% bare steel and 0.07% coated steel, while our transmission system consists of less than 0.63% bare steel. Many of our Gas Utilities are authorized to use system safety, integrity and replacement cost recovery mechanisms that allow them to adjust their rates to reflect all the costs prudently incurred in replacing piping systems.

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, such as SourceGas, 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 will consider such opportunities if they advance our long-term strategy and add shareholder value.

Provide stable long-term gas costs 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 considering implementing a Cost of Service Gas Program. The Cost of Service Gas Program is designed to provide utility customers with long-term natural gas price stability, along with a reasonable expectation of savings over the life of the program, while providing increased earnings opportunities for our shareholders. We will need to apply for and receive regulatory approval from our state utility commissions for the program. Several utilities have cost of service gas programs in place in various states, including in both Wyoming and Montana.

We believe we have a competitive advantage related to a Cost of Service Gas Program 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. We could also provide this service to other utilities.

Focus our oil and gas business to support cost of service gas initiatives. Our oil and gas business is focused on supporting the implementation of a planned utility Cost of Service Gas Program in partnership with our own and other utilities, while maintaining the upside value of our Piceance Basin and other assets. We are divesting non-core assets while retaining those assets best suited for a Cost of Service Gas Program. In previous years, we successfully focused our efforts on proving up the large shale gas resource potential of our southern Piceance Basin asset, while improving our drilling and completion practices for the Mancos. We drilled 17 wells and completed 13, with production meeting or exceeding our expectations on the completed wells. We are currently assessing the Piceance Basin assets to determine their potential fit for a Cost of Service Gas Program.

Oil and Gas will rationalize its asset base. In the current price environment, we have reduced future capital expenditures and staffing to improve financial performance.

Build and maintain strong relationships with wholesale power customers of 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.

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. Over the last decade or so, Black Hills has strategically refocused itself as a utility-centered energy company. Most of our buying and selling activities are directly related to maintaining utilities operations, mainly by purchasing fuel for our power generating units and purchasing natural gas for distribution to our natural gas utility customers. Our oil and gas business has a natural long position created by its natural gas and crude oil production. We sell this production into the open market and hedge some of the price risk for future production using financial derivatives.

All of our buying and selling activities to support 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 committee monitors 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.

Prospective Information

We expect to generate long-term growth through the expansion of integrated utilities and supporting operations. Sustained growth requires continued capital deployment. Our integrated energy portfolio, focused primarily 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 our acquisition of SourceGas, continued focus on improving efficiencies and reducing costs, implementation of a Cost of Service Gas Program and focused capital investments at our utilities. 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.

Electric Utilities

Colorado Electric received a settlement agreement of its electric resource plan filed June 3, 2016, to meet requirements under the Colorado Renewable Energy Standard. The settlement, effective February 6, 2017, includes the addition of 60 megawatts of renewable energy to be in service by 2019 and provides for additional small solar and community solar gardens as part of the compliance plan. Colorado Electric plans to issue a request for proposal in the first half of 2017.

In December 2016, Colorado Electric received approval from the CPUC to increase its annual revenues by $1.2 million to recover investments in a $63 million, 40 MW natural gas-fired combustion turbine. This increase is in addition to approximately $5.9 million in annualized revenue being recovered under the Clean Air Clean Jobs Act construction financing rider. This turbine was completed in the fourth quarter of 2016, achieving commercial operation on December 29, 2016. The approval allowed a return on rate base of 6.02% for this turbine, with a 9.37% return on equity and a capital structure of 67.34% debt and 32.66% equity. Whereas, an authorized return on rate base of 7.4% was received for the remaining system investments, with a return on equity of 9.37% and an approved capital structure of 47.61% debt and 52.39% equity. On January 9, 2017, we filed an application with the CPUC for rehearing, reargument or reconsideration of the Commission’s December 19, 2016 rate decision.

In November 2016, Colorado Electric completed the purchase of Peak View, a $109 million, 60 MW Wind Project located near Colorado Electric's Busch Ranch Wind Farm. Peak View achieved commercial operation on November 7, 2016 and was purchased through progress payments throughout 2016 under a commission approved third-party build transfer and settlement agreement. This renewable energy project was originally submitted in response to Colorado Electric’s all-source generation request on May 5, 2014. The Commission’s settlement agreement provides for recovery of the costs of the project through Colorado Electric’s Electric Cost Adjustments, Renewable Energy Standard Surcharge and Transmission Cost Adjustment for 10 years, after which Colorado Electric can propose base rate recovery. Colorado Electric is required to make an annual comparison of the cost of the renewable energy generated by the facility against the bid cost of a PPA from the same facility.

Retail MWhs sold increased in 2016 primarily due to increased industrial loads driven by customer load growth. The increase in industrial loads is primarily driven by Wyoming Electric and Colorado Electric, both of which set new all-time peak loads in 2016. Wyoming Electric recorded an all-time summer peak load of 236 MW in July 2016, and an all-time winter peak of 230 MW in December 2016. Colorado Electric recorded an all-time summer peak load of 412 MW in July 2016.

During the first quarter of 2016, South Dakota Electric commenced construction of the $54 million, 230-kV, 144 mile-long transmission line that will connect the Teckla Substation in northeast Wyoming to the Lange Substation near Rapid City, South Dakota. Recovery is concurrent through the FERC transmission tariff. The first segment of this project connecting Teckla to Osage, WY was placed in service on August 31, 2016. The second segment connecting Osage to Lange is expected to be placed in service in the first half of 2017.

Gas Utilities

On February 12, 2016, Black Hills Utility Holdings acquired SourceGas pursuant to a purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, which included the assumption of $760 million in debt at closing. The purchase price was subject to post-closing adjustments of which $11 million was agreed to and received in June 2016.

SourceGas, which was renamed Black Hills Gas Holdings, LLC, primarily operates four regulated natural gas utilities serving approximately 431,000 customers in Arkansas, Colorado, Nebraska and Wyoming and a 512 mile regulated intrastate natural gas transmission pipeline in Colorado.

We completed substantially all integration activities in 2016. All significant operations, customer, accounting, human resources and rebranding activities were successfully completed and implemented.

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 reviews 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.

Cost of Service Gas Program Filings

During the third quarter of 2016, the Company withdrew its Cost of Service Gas applications in Wyoming, Iowa, Kansas and South Dakota. In consideration of the July 2016 denial of the application from the NPSC and the April 2016 dismissal of its application from the CPUC, the Company is re-evaluating its Cost of Service Gas regulatory approval strategy.

The Company's initial applications submitted in late 2015 were based on a two-phase approach, the first of which would establish the criteria for how the program would work, and the second would seek approval for a specific gas reserves property. The orders in Colorado and Nebraska indicated the initial phase filings contained insufficient information and data to support customer benefits. The Company is currently considering filing new applications for approval of specific gas reserve properties.

The Cost of Service Gas Program is designed to provide long-term natural gas price stability for the Company's utility customers, along with a reasonable expectation of customer savings over the life of the program.

Mining

Production from the Mining segment primarily serves mine-mouth generation plants and select regional customers with long-term fuel needs. Total annual production was approximately 3.8 million tons for 2016, which was 8% less than 2015. Mining operations moved to an area with higher overburden ratios in 2016, which increased mining costs. However, lower fuel costs, and efficiencies in executing our mine plan offset these costs. Our stripping ratio at December 31, 2016 was 2.07 and we expect stripping ratios to decrease in 2017 to approximately 1.9 as the areas planned for mining contain lower 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 limited off-site sales have been to consumers within a close proximity to our mine, including off-site sales contracts served by truck. We continue to pursue new opportunities to market our coal despite limitations inherent to transporting our lower-heat content coal.

Oil and Gas

Our strategy is to focus our Oil and Gas business toward supporting our Cost of Service Gas Program and similar programs in partnership with other utilities, while maintaining the upside value optionality of our Piceance Basin and other assets. We can best utilize our oil and gas expertise to develop and operate the Cost of Service Gas Program on behalf of our utility businesses and similar programs in partnership with third-party utilities. We are divesting non-core assets while retaining those best suited for a Cost of Service Gas Program. Our oil and gas strategy through 2015 had been to prove up the potential of the Mancos formation for our southern Piceance Basin asset, while improving our drilling and completion practices for the Mancos. We drilled 17 wells and completed 13, with production meeting or exceeding our expectations on the completed wells. Due to the sustained low oil and natural gas prices, production in 2016 was limited to meeting contractual agreements we have in the Piceance, and we have limited our planned future capital based on our Cost of Service Gas strategy. We are currently assessing the Piceance wells and acreage holdings to determine their potential fit for a Cost of Service Gas Program.

Corporate

We took advantage of historically low interest rates to complete several financing transactions, including permanent financing of the SourceGas Acquisition, refinancing on favorable terms the debt acquired in the Acquisition, amending and extending our Revolving Credit Facility and executing a new three-year term loan. In addition to our debt issuances and refinancings, we implemented an ATM equity offering program, executed a declining balance term loan, closed on a CP Program and settled $400 million of interest rate swaps. See additional detail in the 2016 Corporate highlights.

Results of Operations

Executive Summary and Overview

	For the Years Ended December 31,				
	2016	Variance	2015	Variance	2014
	(in thousands)				
Revenue					
Revenue	$1,701,093	$270,811	$1,430,282	$(90,827)	$1,521,109
Inter-company eliminations	(128,119)	(2,442)	(125,677)	1,862	(127,539)
	$1,572,974	$268,369	$1,304,605	$(88,965)	$1,393,570
Net income (loss) available for common stock					
Electric Utilities[(a)]	$85,827	$8,248	$77,579	$20,309	$57,270
Gas Utilities[(a)]	59,624	20,318	39,306	(4,845)	44,151
Power Generation [(b)]	25,930	(6,720)	32,650	4,134	28,516
Mining	10,053	(1,817)	11,870	1,418	10,452
Oil and Gas [(c) (d)]	(71,054)	108,904	(179,958)	(171,433)	(8,525)
	110,380	128,933	(18,553)	(150,417)	131,864
Corporate and Eliminations [(a) (e) (f)]	(37,410)	(23,852)	(13,558)	(12,583)	(975)
Net income (loss) available for common stock	$72,970	$105,081	$(32,111)	$(163,000)	$130,889

(a) Net income available for common stock for 2016 included a net tax benefit of approximately $3.1 million for the following items: at the Electric Utilities, a $2.1 million benefit related to production tax credits associated with the Peak View Wind Project being placed into service and flow through treatment of a treasury grant related to the Busch Ranch Wind Project; at the Gas Utilities, a tax benefit of approximately $2.2 million related to favorable flow through adjustments; and, various other items netting to $1.2 million of tax expense that predominantly affected Corporate.

(b) On April 14, 2016, BHEG sold a 49.9% interest in Black Hills Colorado IPP. Net income available for common stock for 2016 was reduced by $9.6 million attributable to this noncontrolling interest.

(c) Net income (loss) available for common stock for 2016 and 2015 included non-cash after-tax impairments of our crude oil and natural gas properties of $67 million and $160 million. See Note 13 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

(d) Net income (loss) available for common stock for 2016 included a tax benefit of approximately $5.8 million recognized from additional percentage depletion deductions that are being claimed with respect to our oil and gas properties involving prior years.

(e) Net income (loss) available for common stock for 2016 and 2015 include incremental SourceGas Acquisition costs, after-tax of $30 million and $6.7 million and after-tax internal labor costs attributable to the SourceGas Acquisition of $9.1 million and $3.0 million that otherwise would have been charged to other business segments.

(f) Net income (loss) available for common stock for 2016 included tax benefits of approximately $4.4 million as a result of the re-measurement of the liability for uncertain tax positions predicated on an agreement reached with IRS Appeals in early 2016.

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.

2016 Compared to 2015

Net income (loss) available for common stock was $73 million, or $1.37 per diluted share in 2016, compared to $(32) million, or $(0.71) per share in 2015. Net income available for common stock in 2016 increased over the same period in the prior year due primarily to: lower Oil and Gas property impairment charges; higher earnings at our Electric Utilities and Gas Utilities, which include earnings of $15 million from our acquired SourceGas utilities since the acquisition date of February 12, 2016; tax benefits of approximately $11 million from additional Oil and Gas properties' percentage depletion deductions, and the re-measurement of uncertain tax positions' liability predicated on an agreement reached with IRS Appeals. These increases were partially offset by $9.6 million of net income attributable to noncontrolling interests. Non-cash after-tax oil and gas property impairment charges were $67 million and after-tax SourceGas incremental acquisition and transition costs were $30 million in the year ended December 31, 2016. The Net income (loss) available for common stock for the year ended 2015 included non-cash after-tax ceiling test impairments of our oil and gas properties of $158 million, after-tax SourceGas incremental acquisition and transition costs of $6.7 million, and a non-cash after-tax impairment loss on an oil and gas equity investment of $2.9 million.

2016 Overview of Business Segments and Corporate Activity

Electric Utilities

- In our Electric Utilities service territories, mild winter weather in 2016 partially offset a hotter than normal summer. Heating degree days were 2% lower than the prior year and 13% lower than normal. Offsetting this decrease was weather related demand during the peak summer months. Cooling degree days for the full year of 2016 were 9% higher than the same period in the prior year and 26% higher than normal.

- On December 19, 2016, Colorado Electric received approval from the CPUC to increase its annual revenues by $1.2 million to recover investments in a $63 million, 40 MW natural gas-fired combustion turbine. This turbine was completed in the fourth quarter of 2016, achieving commercial operation on December 29, 2016. The approval allowed a return on rate base of 6.02% for this turbine, with a 9.37% return on equity and a capital structure of 67.34% debt and 32.66% equity. Whereas, an authorized return on rate base of 7.4% was received for the remaining system investments, with a return on equity of 9.37% and an approved capital structure of 47.6% debt and 52.4% equity.

Construction riders related to the project increased gross margins by approximately $5.1 million for the year ended December 31, 2016.

- On November 8, 2016, Colorado Electric completed the purchase of Peak View, a $109 million, 60 MW Wind Project located near Colorado Electric's Busch Ranch Wind Farm. Peak View achieved commercial operation on November 7, 2016 and was purchased through progress payments throughout 2016 under a commission approved third-party build- transfer and settlement agreement. This renewable energy project was originally submitted in response to Colorado Electric's all-source generation request on May 5, 2014. The Commission's settlement agreement provides for recovery of the costs of the project through Colorado Electric's Electric Cost Adjustments, Renewable Energy Standard Surcharge and Transmission Cost Adjustment for 10 years, after which Colorado Electric can propose base rate recovery.

- During the first quarter of 2016, South Dakota Electric commenced construction of the $54 million, 230-kV, 144 mile-long transmission line that will connect the Teckla Substation in northeast Wyoming to the Lange Substation near Rapid City, South Dakota. Recovery is concurrent through the FERC transmission tariff. The first segment of this project connecting Teckla to Osage, WY was placed in service on August 31, 2016. The second segment connecting Osage to Lange is expected to be placed in service in the first half of 2017.

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Gas Utilities

- On February 12, 2016, Black Hills Utility Holdings acquired SourceGas Holdings, LLC pursuant to the purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, which included the assumption of $760 million in long-term debt at closing. See additional information below under Corporate activities.

- Gas Utilities were unfavorably impacted by milder weather in 2016 compared to 2015. Our service territories reported warmer than normal winter weather as measured by heating degree days, compared to the 30-year average, and compared to 2015. Heating degree days for the full year in 2016 were 10% less than normal and 1% less than the same period in 2015.

- During the third quarter of 2016, the Company withdrew its Cost of Service Gas applications in Wyoming, Iowa, Kansas and South Dakota. In consideration of the July 2016 denial of the application from the NPSC and the April 2016 dismissal of its application from the CPUC, the Company is re-evaluating its Cost of Service Gas regulatory approval strategy.

The Company's initial applications submitted in late 2015 were based on a two-phase approach, the first of which would establish the criteria for how the program would work, and the second would seek approval for a specific gas reserves property. The orders in Colorado and Nebraska indicated the initial phase filings contained insufficient information and data to support customer benefits. Based on pre-hearing discovery and commission orders, the Company is considering filing new applications for approval of specific gas reserve properties.

Power Generation

- Black Hills Colorado IPP owns and operates a 200 MW, combined cycle natural gas generating facility located in Pueblo, Colorado. On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for $216 million. FERC approval of the sale was received on March 29, 2016. Proceeds from the sale were used to pay down short-term debt. Black Hills Electric Generation continues to be the majority owner and operator of the facility, which is contracted to provide capacity and energy through 2031 to Black Hills Colorado Electric.

Oil and Gas

- Our Oil and Gas segment was impacted by lower net hedged prices received for crude oil and natural gas for the year ended December 31, 2016 compared to the same period in 2015. The average hedged price received for natural gas decreased by 24% for the year ended December 31, 2016 compared to the same period in 2015. The average hedged price received for oil decreased by 6% for the year ended December 31, 2016 compared to the same period in 2015. Oil and Gas production volumes decreased 6% for the year ended December 31, 2016 compared to the same period in 2015 as production was limited to meeting minimum daily quantity contractual gas processing requirements in the Piceance.

- We review the carrying value of our natural gas and crude oil properties under the full cost accounting rules of the SEC on a quarterly basis, known as a ceiling test. We recorded a non-cash ceiling test impairment charge in each quarter of 2016 totaling $92 million for the year ended December 31, 2016. We also recorded a $14 million impairment of other Oil and Gas depreciable properties not included in our full cost pool during the second quarter of 2016 as we advanced our strategy to divest non-core oil and gas assets. In 2016, we sold non-core assets for total proceeds of $11 million.

Corporate Activities

- On March 18, 2016, we implemented an ATM equity offering program allowing us to sell shares of our common stock with an aggregate value of up to $200 million. The shares may be offered from time to time pursuant to a sales agreement dated March 18, 2016. Shares of common stock are offered pursuant to our shelf registration statement filed with the SEC. Through December 31, 2016, we have sold and issued an aggregate of 1,968,738 shares of common stock under the ATM equity offering program for $119 million, net of $1.2 million in commissions.

- On December 22, 2016, we implemented a $750 million, unsecured CP Program that is backstopped by the Revolving Credit Facility. Amounts outstanding under the Revolving Credit Facility and the CP Program, either individually or in the aggregate, cannot exceed $750 million. The notes issued under the CP Program may have maturities not to exceed 397 days from the date of issuance and bear interest (or are sold at par less a discount representing an interest factor) based on, among other things, the size and maturity date of the note, the frequency of the issuance and our credit ratings. We did not borrow under the CP Program in 2016 and do not have any notes outstanding as of December 31, 2016.

- On December 9, 2016, Moody's issued a Baa2 rating with a Stable outlook, which reflects the higher debt leverage resulting from the incremental debt used to fund the SourceGas Acquisition.

- On August 19, 2016, we completed a public debt offering of $700 million principal amount of senior unsecured notes. The debt offering consisted of $400 million of 3.15% 10-year senior notes due January 15, 2027 and $300 million of 4.20% 30-year senior notes due September 15, 2046. The proceeds of the notes were used for the following:

Repay the $325 million 5.9% senior unsecured notes assumed in the SourceGas Acquisition;

Repay the $95 million, 3.98% senior secured notes assumed in the SourceGas Acquisition;

Repay the remaining $100 million on the $340 million unsecured term loan assumed in the SourceGas Acquisition;

Pay down $100 million of the $500 million three-year unsecured term loan discussed below;

Payment of $29 million for the settlement of $400 million notional interest rate swaps; and

Remainder was used for general corporate purposes.

- On August 9, 2016, we entered into a $500 million, three-year, unsecured term loan expiring on August 9, 2019. The proceeds of this term loan were used to pay down $240 million of the $340 million unsecured term loan assumed in the SourceGas Acquisition and the $260 million term loan expiring on April 12, 2017.

- On August 9, 2016, we amended and restated our corporate Revolving Credit Facility to increase total commitments to $750 million from $500 million and extended the term through August 9, 2021, with two, one-year extension options (subject to consent from the lenders). The facility includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents and subject to receipt of additional commitments from existing or new lenders, to increase total commitments of the facility up to $1 billion. Borrowings continue to be available under a base rate or various Eurodollar rate options, which are substantially the same as the former agreement.

- On June 7, 2016, we issued a $29 million, declining balance five-year term loan maturing June 7, 2021, to finance the early termination of a gas supply agreement.

- During the first quarter of 2016, we reached an agreement in principle with IRS Appeals with respect to our liability for unrecognized tax benefits attributable to the like-kind exchange effectuated in connection with the 2008 IPP Transaction and the 2008 Aquila Transaction. This agreement resulted in a tax benefit of approximately $5.1 million in the first quarter of 2016. See Note 15 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for additional details on this agreement.

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On February 12, 2016, Black Hills Utility Holdings acquired SourceGas Holdings, LLC pursuant to the purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, which included the assumption of $760 million in long-term debt at closing. We funded the majority of the SourceGas Transaction with the following financings:

- On January 13, 2016, we completed a public debt offering of $550 million in senior unsecured notes. The debt offering consists of $300 million of 3.95%, 10-year senior notes due 2026, and $250 million of 2.50%, 3-year senior notes due 2019. Net proceeds after discounts and fees were approximately $546 million; and

- On November 23, 2015, we completed the offerings of common stock and equity units. We issued 6.325 million shares of common stock for net proceeds of $246 million and 5.98 million equity units for net proceeds of approximately $290 million.

- On February 12, 2016, S&P affirmed the BHC credit rating of BBB and maintained a stable outlook after our acquisition of SourceGas, reflecting their expectation that management will continue to focus on the core utility operations while maintaining an excellent business risk profile following the acquisition.

- On February 12, 2016, Fitch affirmed the BHC credit rating of BBB+ and maintained a negative outlook after our acquisition of SourceGas, which reflects the initial increased leverage associated with the SourceGas Acquisition.

- On January 20, 2016, we executed a 10-year, $150 million notional, forward starting pay fixed interest rate swap at an all-in interest rate of 2.09%, and on October 2, 2015, we executed a 10-year, $250 million notional forward starting pay fixed interest rate swap at an all-in rate of 2.29%, to hedge the risks of interest rate movement between the hedge dates and pricing date for long-term debt refinancings occurring in August 2016. On August 19, 2016, we settled and terminated these interest rate swaps for a loss of $29 million. The loss recorded in AOCI is being amortized over the 10-year life of the associated debt.

2015 Compared to 2014

Net income (loss) was $(32) million, or $(0.71) per share, in 2015 compared to $131 million, or $2.93 per share, in 2014. 2015 Net income (loss) included a non-cash after-tax ceiling test impairment charge to our crude oil and natural gas properties of $158 million and a non-cash after-tax equity investment impairment charge of $2.9 million. 2015 Net income (loss) also included after-tax, external third-party costs of $6.7 million, primarily attributable to the SourceGas Acquisition. The 2014 Net income (loss) did not include any expenses, gains, or losses that we believe are not representative of our core operating performance.

2015 Overview of Business Segments and Corporate Activity

Electric Utilities

- In our Electric Utilities service territories, mild winter weather in 2015 offset a hotter than normal summer. Heating degree days were 11% lower than the prior year and 10% lower than normal. Offsetting this was weather related demand during the peak summer months. Cooling degree days for the full year of 2015 were 32% higher than the same period in the prior year and 16% higher than normal.

- Construction commenced in the second quarter of 2015 on Colorado Electric’s $63 million 40 MW natural gas-fired combustion turbine. As of December 31, 2015, approximately $35 million was expended Construction riders related to the project increased gross margins by approximately $1.9 million for the year ended December 31, 2015. This turbine was completed in and placed into service in December 2016.

- On July 23, 2015, South Dakota Electric received approval from the WPSC for a CPCN 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. South Dakota Electric received approval on November 6, 2014 from the SDPUC for a permit to construct the South Dakota portion. Construction commenced in the first quarter of 2016, and the project is expected to be placed in service in the first half of 2017.

- On June 23, 2015, Colorado Electric filed for a CPCN with the CPUC to acquire the planned 60 MW Peak View Wind Project, to be located near Colorado Electric's Busch Ranch Wind Farm. This renewable energy project was originally submitted in response to Colorado Electric's all-source generation request on May 5, 2014. On October 21, 2015, the Commission approved a build transfer proposal and settlement agreement. The settlement provides for recovery of the costs of the project through Colorado Electric’s Electric Cost Adjustments and Renewable Energy Standard Surcharge for 10 years, after which Colorado Electric can propose base rate recovery. Colorado Electric will be required to make an annual comparison of the cost of the renewable energy generated by the facility against the bid cost of a PPA from the same facility. Colorado Electric purchased the project from a third-party for approximately $109 million through progress payments throughout 2016, with ownership transfer occurring on November 7, 2016.

- On March 16, 2015, we announced plans to build a new corporate headquarters in Rapid City, South Dakota that will consolidate our approximately 500 employees in Rapid City from five locations into one. The investment in the new corporate headquarters will be approximately $70 million and will support all our businesses. The cost of the facility will replace existing expenses associated with our current facilities throughout Rapid City. Construction began in September 2015 with completion expected in the fall of 2017.

- On March 2, 2015, the SDPUC issued an order approving a rate stipulation and agreement authorizing an annual electric revenue increase for South Dakota Electric of $6.9 million. The agreement was a Global Settlement and did not stipulate return on equity and capital structure. The SDPUC's decision provides South Dakota Electric 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. South Dakota Electric implemented interim rates on October 1, 2014, coinciding with Cheyenne Prairie's commercial operation date. Final rates were approved on April 1, 2015, effective October 1, 2014.

- In January 2015, Colorado Electric implemented new rates in accordance with the CPUC approval received on December 19, 2014 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 a construction financing rider. This approval allows Colorado Electric to recover increased operating expenses and infrastructure investments, including those for the Busch Ranch Wind Farm, placed in service late 2012. The implementation of the rider allows Colorado Electric to recover a return on the construction costs for a $63 million natural gas-fired combustion turbine that was constructed in 2015 and 2016 to replace the retired W.N. Clark power plant.

Gas Utilities

- Gas Utilities were unfavorably impacted by milder weather in 2015 compared to 2014. Our service territories reported warmer than normal winter weather as measured by heating degree days, compared to the 30-year average, and compared to 2014. Heating degree days for the full year in 2015 were 8% less than normal and 13% less than the same period in 2014.

- On July 1, 2015, we completed the acquisition of Wyoming natural gas utility Energy West Wyoming, Inc., and natural gas pipeline assets from Energy West Development, Inc. The utility and pipeline assets were acquired for approximately $17 million, and operate as subsidiaries of Wyoming Electric. The acquired system serves approximately 6,700 customers, in Cody, Ralston, and Meeteetse, Wyoming. The pipeline acquisition includes a 30 mile gas transmission pipeline and a 42 mile gas gathering pipeline, both located near the utility service territory.

- In January 2015, Kansas Gas implemented new base rates in accordance with the rate request approval received on December 16, 2014 from the KCC to increase base rates by $5.2 million. This increase in base rates allows Kansas Gas to recover infrastructure and increased operating costs. The approval was a Global Settlement and did not stipulate return on equity and capital structure.

Oil and Gas

- Our Oil and Gas segment was impacted by lower commodity prices for crude oil and natural gas for the year ended December 31, 2015 compared to the same period in 2014. The average hedged price received for natural gas decreased by 39% for the year ended December 31, 2015 compared to the same period in 2014. The average hedged price received for oil decreased by 24% for the year ended December 31, 2015 compared to the same period in 2014. Oil and Gas production volumes increased 29% for the year ended December 31, 2015 compared to the same period in 2014.

- 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, known as a ceiling test. We recorded a non-cash ceiling impairment charge in each quarter of 2015, totaling $250 million for the year ended December 31, 2015.

- We finished drilling the last of 13 Mancos Shale wells for our 2014/2015 drilling program in the Piceance Basin. Nine wells were placed on production in 2015, all with favorable production results to date, exceeding our expectations. We deferred the completion of our four remaining wells due to insufficient gas processing capacity and our expectation of continued low commodity prices. During the second quarter of 2015, we also reduced our planned 2016 and 2017 capital expenditures due to our strategic decision to focus our oil and gas expertise on being a cost of service gas provider for our electric and natural gas utilities.

Corporate Activities

- On July 12, 2015 we entered into a definitive agreement to acquire SourceGas for approximately $1.89 billion, which included an estimated $200 million in capital expenditures through closing and the assumption of $760 million in long-term debt at closing. This acquisition closed on February 12, 2016. Financing activities related to this acquisition are detailed above in the 2016 Corporate activities.

- On June 26, 2015, we amended our $500 million corporate Revolving Credit Facility agreement to extend the term one year, through June 26, 2020. This facility is 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.

- On April 13, 2015, we entered into a new $300 million unsecured term loan. The loan has a two-year term with a maturity date of April 12, 2017. Proceeds of the term note were used to repay the existing $275 million term note due June 19, 2015.

Operating Results

A discussion of operating results from our business segments follows.

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

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):

	2016	Variance	2015	Variance	2014
Revenue	$677,281	$(2,562)	$679,843	$22,287	$657,556
Total fuel and purchased power	261,349	(8,060)	269,409	(22,235)	291,644
Gross margin	415,932	5,498	410,434	44,522	365,912
Operations and maintenance	158,134	(2,790)	160,924	4,672	156,252
Depreciation and amortization	84,645	3,716	80,929	3,918	77,011
Total operating expenses	242,779	926	241,853	8,590	233,263
Operating income	173,153	4,572	168,581	35,932	132,649
Interest expense, net	(50,291)	754	(51,045)	(3,995)	(47,050)
Other income, net	3,193	1,977	1,216	142	1,074
Income tax expense	(40,228)	945	(41,173)	(11,770)	(29,403)
Net income (loss) available for common stock	$85,827	$8,248	$77,579	$20,309	$57,270

	2016	2015	2014
Regulated power plant fleet availability:			
Coal-fired plants [(a) (b)]	90.2%	91.5%	93.8%
Other plants [(c)]	95.1%	95.4%	90.2%
Total availability	93.5%	94.0%	91.5%

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(a) 2016 reflects a planned outage at Wygen III and unplanned outages at Wyodak and Neil Simpson II.

(b) 2015 reflects planned outages at Neil Simpson II, Wygen II and Wygen III.

(c) 2014 reflects planned overhauls for control system upgrades to meet NERC cyber security regulations on the Ben French CTs 1-4.

2016 Compared to 2015

Gross margin increased over the prior year reflecting increased rider margins of $4.9 million driven primarily by our construction and TCA riders, an increase of $2.4 million in commercial and industrial margins driven by increased demand, a $1.5 million return on investment from the Peak View Wind Project, and a $1.4 million increase in residential margins driven by favorable weather. Offsetting these increases was a $2.1 million prior-year benefit as a result of a one-time settlement with the Colorado Public Utilities Commission on our renewable energy standard adjustment related to the Busch Ranch wind farm, a prior-year increase in return on invested capital of $1.2 million from South Dakota Electric's rate case, and a $1.3 million decrease due to third-party billing true-ups relating to the current and prior years.

Operations and maintenance decreased primarily as a result of approximately $5.8 million lower employee costs primarily driven by a change in expense allocations impacting the electric utilities as a result of integrating the acquired SourceGas utilities. This decrease is partially offset by higher operating costs from the Peak View Wind Project, which commenced commercial operation in November 2016, and increased vegetation management costs.

Depreciation and amortization increased primarily due to a higher asset base driven partially by the addition of Peak View Wind Project.

Interest expense, net decreased primarily due to higher AFUDC interest income driven by construction in process as compared to prior year.

Other (expense) income, net increased primarily due to higher AFUDC equity in the current period compared to prior year.

Income tax benefit (expense): The effective tax rate was lower than prior year primarily due to the accelerated recognition of benefits associated with certain tax incentives.

2015 Compared to 2014

Gross margin increased primarily due to a return on additional investments which increased base electric margins by $29.8 million, and increased electric cost recoveries by $4.8 million. Higher industrial and commercial megawatt hours sold driven by customer load growth increased margins by $5.9 million. Colorado Electric received approval of a one-time settlement agreement from the CPUC on our renewable energy standard adjustment related to Busch Ranch, which increased margins by $2.1 million. An increase in residential customer growth and usage per customer increased margins by $2.4 million. These increases are partially offset by a $1.7 million decrease from lower demand and residential megawatt hours sold primarily driven by an 11% decrease in heating degree days compared to the same period in the prior year, and facility improvements at one of our large industrial customers which resulted in a $1.8 million decrease in technical service revenues in the prior year.

Operations and maintenance increased primarily due to costs related to Cheyenne Prairie, which was placed into commercial service on October 1, 2014.

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

Interest expense, net increased primarily due to interest costs from the $160 million of permanent financing placed during the fourth quarter of 2014 for Cheyenne Prairie.

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

Gas Utilities

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

	2016	Variance	2015	Variance	2014
Revenue:					
Natural gas - regulated	$769,082	$249,084	$519,998	$(107,135)	$627,133
Other - non-regulated	69,261	37,959	31,302	912	30,390
Total revenue	838,343	287,043	551,300	(106,223)	657,523
Cost of natural gas sold:					
Natural gas - regulated	315,618	31,985	283,633	(104,330)	387,963
Other - non-regulated	36,547	20,535	16,012	194	15,818
Total cost of natural gas sold	352,165	52,520	299,645	(104,136)	403,781
Gross margin:					
Natural gas - regulated	453,464	217,099	236,365	(2,805)	239,170
Other - non-regulated	32,714	17,424	15,290	718	14,572
Total gross margin	486,178	234,523	251,655	(2,087)	253,742
Operations and maintenance	245,826	105,103	140,723	(1,301)	142,024
Depreciation and amortization	78,335	46,009	32,326	3,414	28,912
Total operating expenses	324,161	151,112	173,049	2,113	170,936
Operating income	162,017	83,411	78,606	(4,200)	82,806
Interest expense, net	(75,013)	(57,702)	(17,311)	(290)	(17,021)
Other expense (income), net	184	(131)	315	191	124
Income tax expense	(27,462)	(5,158)	(22,304)	(546)	(21,758)
Net income (loss)	59,726	20,420	39,306	(4,845)	44,151
Net income attributable to noncontrolling interest	(102)	(102)	—	—	—
Net income (loss) available for common stock	$59,624	$20,318	$39,306	$(4,845)	$44,151

2016 Compared to 2015

Gross margin increased primarily due to margins of approximately $236 million contributed by the SourceGas utilities acquired on Feb. 12, 2016 and Energy West Wyoming utility acquired on July 1, 2015. Partially offsetting this increase is a $ 2.0 million decrease due to weather. Heating degree days were 1% lower than the prior year and 10% lower than normal.

Operations and maintenance increased primarily due to additional operating costs of approximately $111 million for the acquired SourceGas utilities and Energy West Wyoming utility. Partially offsetting this increase were approximately $7.4 million lower employee costs primarily driven by a change in expense allocations impacting the gas utilities as a result of integrating the acquired SourceGas utilities.

Depreciation and amortization increased primarily due to additional depreciation from the acquired SourceGas and Energy West Wyoming utilities of approximately $45 million, and due to a higher asset base at our other gas utilities over the same period in the prior year.

Interest expense, net increased primarily due to additional interest expense of approximately $58 million from the debt associated with the acquired SourceGas utilities.

Income tax: The effective tax rate for 2016, including the impact of the acquired SourceGas and Energy West Wyoming utilities, reflects additional tax benefits related primarily to a favorable flow through adjustment. Such adjustments are related to certain tax benefits that are recognized currently in accordance with prescribed regulatory treatment.

2015 Compared to 2014

Gross margin decreased primarily due to a $10.8 million impact from milder weather compared to the same period in the prior year and a $2.3 million decrease in retail volumes sold. Heating degree days in 2015 were 14% lower than the prior year and 8% lower than normal. Partially offsetting these decreases was $3.6 million of increased margins from the 2015 MCTC and Energy West Wyoming acquisitions, the impact from base rate increases from Kansas Gas, and an increase of $1.5 million from year over year customer growth.

Operations and maintenance decreased primarily due to lower operating expenses, partially offset by an increase in property taxes.

Depreciation and amortization increased primarily due to a higher asset base than the prior year.

Interest expense, net is comparable to the prior year.

Income tax: The effective tax rate for 2015 is higher primarily due to a less favorable return to accrual adjustment related to flow-through items when compared to the prior year.

Power Generation

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

	2016	Variance	2015	Variance	2014
Revenue	$91,131	$341	$90,790	$3,232	$87,558
Operations and maintenance	32,636	496	32,140	(986)	33,126
Depreciation and amortization	4,104	(225)	4,329	(211)	4,540
Total operating expenses	36,740	271	36,469	(1,197)	37,666
Operating income	54,391	70	54,321	4,429	49,892
Interest expense, net	(1,775)	1,428	(3,203)	466	(3,669)
Other income (expense), net	2	(69)	71	77	(6)
Income tax expense	(17,129)	1,410	(18,539)	(838)	(17,701)
Net income (loss)	35,489	2,839	32,650	4,134	28,516
Net income attributable to noncontrolling interest	(9,559)	(9,559)	—	—	—
Net income (loss) available for common stock	$25,930	$(6,720)	$32,650	4,134	$28,516

On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for $216 million. Black Hills Electric Generation continues to be the majority owner and operator of the facility, which is contracted to provide capacity and energy through 2031 to Black Hills Colorado Electric. Net income available for common stock for the year ended December 31, 2016, was reduced by $9.6 million attributable to this noncontrolling interest. The net income allocable to the noncontrolling interest holders is based on ownership interests with the exception of certain agreed upon adjustments.

	2016	2015	2014
Contracted fleet plant availability:			
Gas-fired plants	99.2%	99.1%	99.0%
Coal-fired plants [(a)]	95.5%	98.4%	94.7%
Total	98.3%	98.9%	97.8%

(a) Wygen I experienced an unplanned outage in 2016 and a planned outage in 2014.

2016 Compared to 2015

Revenue increased primarily due to increased PPA prices, partially offset by a decrease in contracted revenue driven by the Wygen I plant outage in the second quarter of 2016.

Operations and maintenance increased primarily due to fan upgrades to the Colorado IPP generator and increased Wygen I chemical and major maintenance costs as compared to the same period in the prior year.

Depreciation and amortization decreased primarily due to lower depreciation at Wygen I. 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 due to higher interest income driven by the proceeds from the noncontrolling interest sale in April 2016.

Income tax expense: Black Hills Colorado IPP went from a single member LLC, wholly owned by Black Hills Generation, to a partnership as a result of the sale of 49.9 percent of its membership interest in April 2016. The effective tax rate reflects the income attributable to the noncontrolling interest for which a tax provision was not recorded.

Net income attributable to noncontrolling interest: Net income attributable to the noncontrolling interest increased by $9.6 million as a result of the noncontrolling interest sale in April 2016.

2015 Compared to 2014

Revenue increased primarily due to an increase in megawatt hours delivered at higher prices and an increase in fired hours, partially offset by the net effect of the expiration of the Gillette CTII PPA and subsequent economy energy PPA, which was impacted by lower natural gas prices in 2015.

Operations and maintenance decreased primarily due to lower outside services and materials, and maintenance costs from the Wygen I outage in the prior year.

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 favorable interest income driven by a higher allocated note receivable compared to the same period in the prior year.

Income tax expense: The effective tax rate was lower in 2015 primarily due to an unfavorable return to accrual adjustment recorded in 2014. Such adjustment was related to the filed 2013 income tax return.

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Mining

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

	2016	Variance	2015	Variance	2014
Revenue	$60,280	$(4,786)	$65,066	$1,708	$63,358
Operations and maintenance	39,576	(2,054)	41,630	458	41,172
Depreciation, depletion and amortization	9,346	(460)	9,806	(470)	10,276
Total operating expenses	48,922	(2,514)	51,436	(12)	51,448
Operating income (loss)	11,358	(2,272)	13,630	1,720	11,910
Interest (expense) income, net	(377)	22	(399)	35	(434)
Other income, net	2,209	(38)	2,247	(28)	2,275
Income tax benefit (expense)	(3,137)	471	(3,608)	(309)	(3,299)
Net income (loss) available for common stock	$10,053	$(1,817)	$11,870	$1,418	$10,452

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

	2016	2015	2014
Tons of coal sold	3,817	4,140	4,317
Cubic yards of overburden moved (a)	7,916	6,088	4,646
Coal reserves at year-end	199,905	203,849	208,231

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(a) Increase in overburden was due to relocating mining operations to areas of the mine with higher overburden.

2016 Compared to 2015

Revenue decreased primarily due to an 8 percent decrease in tons sold resulting from a planned five-week outage in the second quarter of 2016, which was extended by an additional six weeks at Wyodak plant due to an unplanned major repair of a turbine rotor. Pricing was comparable to the same period in the prior year. Approximately 50 percent of our coal production was sold under contracts that are priced based on actual mining costs, including income taxes, as compared to 46 percent for the same period in the prior year.

Operations and maintenance decreased due to lower major maintenance requirements, fuel costs, and employee costs, as well as decreased royalties and revenue-related taxes driven by decreased revenue compared to the same period in the prior year.

Depreciation, depletion and amortization decreased primarily due to revised cost estimates for our asset retirement obligation driving lower accretion and depreciation.

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

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

2015 Compared to 2014

Revenue increased primarily due to a 7% increase in the price per ton sold driven primarily by a coal price increase with the third-party operator of the Wyodak plant. Partially offsetting this was a 4% decrease in tons of coal sold primarily driven by a forced outage at Neil Simpson II, and the decommissioning of Neil Simpson I in March of the prior year. Approximately 50% of our coal production is sold under contracts that include price adjustments based on actual mining costs, including income taxes.

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

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

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

Oil and Gas

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

	2016	Variance	2015	Variance	2014
Revenue	$34,058	$(9,225)	$43,283	$(11,831)	$55,114
Operations and maintenance	32,158	(9,435)	41,593	(1,066)	42,659
Depreciation, depletion and amortization	13,902	(15,385)	29,287	5,041	24,246
Impairment of long-lived assets	106,957	(142,651)	249,608	249,608	—
Total operating expenses	153,017	(167,471)	320,488	253,583	66,905
Operating income (loss)	(118,959)	158,246	(277,205)	(265,414)	(11,791)
Interest expense, net	(4,864)	(2,355)	(2,509)	(824)	(1,685)
Other income (expense), net	110	447	(337)	(520)	183
Impairment of equity investments	—	4,405	(4,405)	(4,405)	—
Income tax benefit (expense)	52,659	(51,839)	104,498	99,730	4,768
Net income (loss) available for common stock	$(71,054)	$108,904	$(179,958)	$(171,433)	$(8,525)

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

Crude Oil and Natural Gas Production	2016	2015	2014
Bbls of oil sold	318,613	371,493	337,196
Mcf of natural gas sold	9,430,288	10,057,378	7,155,076
Bbls of NGL sold	133,304	101,684	134,555
Mcf equivalent sales	12,141,790	12,896,440	9,985,584

Average Price Received [a] [b]	2016	2015	2014
Gas/Mcf	$1.36	$1.78	$2.91
Oil/Bbl	$57.34	$60.69	$79.39
NGL/Bbl	$12.27	$13.66	$35.53

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(a) Net of hedge settlement gains/losses

(b) Impairment charges of $107 million and $250 million were recorded for the years ended December 31, 2016 and 2015, respectively.

	2016	2015	2014
Depletion expense/Mcfe [a]	$0.79	$1.91	$1.84

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(a) The average depletion rate per Mcfe is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented. 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:

	2016			
	LOE	Gathering, Compression, Processing and Transportation	Production Taxes	Total
San Juan	$1.67	$ 1.14	$ 0.33	$3.14
Piceance	0.37	1.84	(0.06)	2.15
Powder River	2.20	—	0.63	2.83
Williston	1.45	—	0.70	2.15
All other properties	1.30	—	0.14	1.44
Average	$1.05	$ 1.20	$ 0.18	$2.43

	2015			
	LOE	Gathering, Compression, Processing and Transportation	Production Taxes	Total
San Juan	$1.44	$ 1.27	$ 0.34	$3.05
Piceance	0.34	1.97	0.19	2.50
Powder River	2.03	—	0.58	2.61
Williston	1.07	—	0.44	1.51
All other properties	1.75	0.02	0.49	2.26
Average	$1.03	$ 1.23	$ 0.32	$2.58

	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

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.

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, and in 2015, we did not meet the minimum requirements of this contract until mid-February. We have excess production capacity from wells completed in 2015, and four additional wells which have not been completed, therefore do not foresee any challenges in our ability to meet this commitment. Our gathering, compression and processing costs on a per Mcfe basis, as shown in the tables above, will be higher in periods when we are not meeting the minimum contract requirements.

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

	2016	2015	2014
Bbls of oil (in thousands)	2,242	3,450	4,276
MMcf of natural gas	54,570	73,412	65,440
Bbls of NGLs (in thousands)	1,712	1,752	1,720
Total MMcfe	78,294	104,624	101,416

Reserves are based on reports prepared by CG&A, an independent consulting and engineering firm. Reserves are 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 2016 production of approximately 12.1 Bcfe, additions from extensions, discoveries and acquisitions (sales) of (4.7) Bcfe and negative revisions to previous estimates of (9.4) Bcfe, primarily due to oil and natural gas prices.

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

	2016		2015		2014	
	Oil	Gas (a)	Oil	Gas	Oil	Gas
NYMEX prices	$42.75	$2.48	$50.28	$2.59	$94.99	$4.35
Well-head reserve prices	$37.35	$2.25	$44.72	$1.27	$85.80	$3.33

(a) For reserves purposes, costs to gather gas previously netted from the gas price were reclassified into operating expenses in 2016, with approximate rates of $1.54/Mcf for Piceance, $0.92/Mcf for San Juan and $0.53/Mcf for all others. For accounting purposes, consistent with prior years, the sales price for natural gas is adjusted for transportation costs and other related deductions when applicable, as further described in Note 1 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

2016 Compared to 2015

Revenue decreased primarily due to lower commodity prices for both crude oil and natural gas, resulting in a 24 percent decrease in the average price received, including hedges, for natural gas sold and a 6 percent decrease in the average price received, including hedges, for crude oil sold. In addition, production decreased by 6 percent as compared to prior year as we limited natural gas production to meet minimum daily quantity contractual gas processing commitments in the Piceance. Crude oil production also decreased due to non-core property sales in the fourth quarter of 2016.

Operations and maintenance decreased primarily due to lower employee costs as a result of the reduction in staffing in the prior year, and lower production taxes and ad valorem taxes on lower revenue.

Depreciation, depletion and amortization decreased primarily due to a reduction of our full cost pool resulting from the ceiling test impairments incurred in current and prior years.

Impairment of long-lived assets represents a non-cash write-down in the value of our natural gas and crude oil properties driven by low natural gas and crude oil prices and movement of certain unevaluated assets into the full-cost pool. The write-down of $107 million included a $14 million write-down of depreciable properties excluded from our full-cost pool and a ceiling test write-down of $93 million. The ceiling test write-down for the 12 months ended December 31, 2016 used an average NYMEX natural gas price of $2.48 per Mcf, adjusted to $2.25 per Mcf at the wellhead, and $42.75 per barrel for crude oil, adjusted to $37.35 per barrel at the wellhead, compared to the $250 million ceiling test write-down in the same period of the prior year which used an average NYMEX natural gas price of $2.59 per Mcf, adjusted to $1.27 per Mcf at the wellhead, and $50.82 per barrel for crude oil, adjusted to $44.72 per barrel at the wellhead.

Interest expense, net increased primarily due to higher interest expense driven by an increase in intercompany notes payable.

Impairment of equity investments represents a prior year non-cash write-down in equity investments related to interests in a pipeline and gathering system. The impairment resulted from continued declining performance, market conditions, and a change in view of the economics of the facilities that we considered to be other than temporary.

Income tax (expense) benefit: Each period reflects a tax benefit. The effective tax rate for 2016 was impacted by a benefit of approximately $5.8 million from additional percentage depletion deductions being claimed with respect to a change in estimate for tax purposes. Such deductions are primarily the result of a change in the application of the maximum daily limitation of 1,000 Bbls of oil equivalent allowed under the Internal Revenue Code.

2015 Compared to 2014

Revenue decreased primarily due to lower commodity prices for both crude oil and natural gas, resulting in a 24 percent decrease in the average price received, including hedges, for crude oil sold and a 39 percent decrease in the average price received, including hedges, for natural gas sold. A 29 percent production increase driven by the nine Piceance Mancos shale wells placed on production in 2015 partially offset the decrease in commodity prices.

Operations and maintenance decreased primarily due to lower production taxes and ad valorem taxes on lower revenue, partially offset by severance costs.

Depreciation, depletion and amortization increased primarily due to a higher depletion rate applied to increased production, partially offset by the reduction in our full cost pool as a result of the impact from the ceiling test impairments in the current year.

Impairment of long-lived assets represents a non-cash write-down in the value of our natural gas and crude oil properties driven by low natural gas and crude oil prices. The write-down reflected a trailing 12 month average NYMEX price of $2.59 per Mcf, adjusted to $1.27 per Mcf at the wellhead, for natural gas, and $50.28 per barrel, adjusted to $44.72 per barrel at the wellhead, for crude oil.

Interest expense, net increased primarily due to third-party interest received on non-operated well revenue in the prior year that offset 2014 expense.

Impairment of equity investments represents a non-cash write-down in equity investments related to interests in a pipeline gathering system. The impairment resulted from continued declining performance, market conditions, and a change in the view of the economics of the facilities that we considered to be other than temporary.

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

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.

2016 Compared to 2015

Net income (loss) available for common stock for the twelve months ended December 31, 2016, was $(37) million compared to net (loss) available for common stock of $(14) million for the same period in the prior year. The variance from the prior year was due to higher corporate expenses, primarily driven by costs related to the SourceGas Acquisition including approximately $30 million of after-tax acquisition and transition costs compared to $6.7 million of after-tax acquisition costs in the prior year, and approximately $9.1 million of after-tax internal labor that otherwise would have been charged to other business segments during the year ended December 31, 2016, compared to $3.0 million of after-tax internal labor that otherwise would have been charged to other business segments during the year ended December 31, 2015. These costs were partially offset by a tax benefit of approximately $4.4 million recognized during the year ended December 31, 2016 as a result of an agreement reached with IRS Appeals relating to the release of the reserve for after-tax interest expense previously accrued with respect to the liability for uncertain tax positions involving a like-kind exchange transaction from 2008.

2015 Compared to 2014

Net income (loss) available for common stock for the twelve months ended December 31, 2015, was $(14) million compared to net income (loss) available for common stock of $(1) million for the same period in the prior year. The variance from the prior year was due to higher corporate expenses, primarily driven by costs related to the SourceGas Acquisition including approximately $4.3 million of after-tax bridge financing costs recognized in interest expense, approximately $3.0 million of after-tax internal labor that otherwise would have been charged to other business segments, and approximately $2.3 million in after-tax other expenses attributable to the acquisition during the year ended December 31, 2015, compared to the same period in the prior year.

Critical Accounting Policies Involving Significant 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 a goodwill impairment test on an annual basis or upon the occurrence of events or changes in circumstances that indicate that the asset might be impaired. Beginning in 2016, we changed our annual goodwill impairment testing date from November 30 to October 1 to better align the testing date with our financial planning process. We believe that the change in the date of the annual goodwill impairment test from November 30 to October 1 is not a material change in the application of an accounting principle. The new and old testing dates are close in proximity; both are in the fourth quarter of the year, and our current testing date is within ten months of the most recent impairment testing. We would not expect a materially different outcome as a result of testing on October 1 as compared to November 30. The change in assessment date does not have a material effect on the financial statements.

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. 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 have determined that the reporting units for goodwill impairment testing are our operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which segment management regularly reviews the operating results. 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 and adjusted as appropriate for our view of market participant assumptions, with long range cash flows estimated using a terminal value calculation, 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. Varying by reporting unit, the weighted average cost of capital in the range of 5% to 8% and the long-term growth rate projections in the 1% to 2% range were utilized in the goodwill impairment test performed in the fourth quarter of 2016. Although 1% to 2% was used for a long-term growth rate projection, the short-term projected growth rate is higher with planned recovery of capital investments through rider mechanisms and rate cases, as well as other improved efficiency and cost reduction initiatives. Under the market approach, we estimate fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition we add a reasonable control premium when calculating fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants.

The estimates and assumptions used in the impairment assessments are based on available market information, and we believe they are reasonable. However, variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated. For the years ended December 31, 2016, 2015, and 2014, there were no significant impairment losses recorded. At December 31, 2016, the fair value substantially exceeded the carrying value at all reporting units.

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 throughout 2016, which required an after-tax write-down of

$58 million for the year ended December 31, 2016. Reserves in 2016 and 2015 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 adjusted for contracted price changes. Because of the fluctuations in natural gas and oil prices, we can provide no assurance that future write-downs will not occur.

Oil, Natural Gas, and Natural Gas Liquids Reserve Estimates

Estimates of our proved crude 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 crude 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 crude 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 crude 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 crude 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 9, “Risk Management Activities” and Note 10, “Fair Value Measurements,” of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Derivatives

We currently use derivative instruments, including options, swaps, and futures, to mitigate commodity purchase price risk and manage interest rate risk. Our typical hedging transactions fix the price received for anticipated future production at our Oil and Gas segment, or to fulfill the natural gas hedging plans for our Gas and Electric utilities. We also enter into interest rate swaps to convert a portion of our variable rate debt, or associated variable rate interest payments, to a fixed rate.

Accounting standards for derivatives require the recognition of all derivative instruments at fair value with changes in fair value ultimately recorded in the income statement. Our policy for recognizing the changes in fair value of these derivatives in earnings is contingent upon whether the derivative has been designated and qualified as part of a hedging relationship or if regulatory accounting requirements require a different accounting treatment. For gas derivatives in our regulated utility business, changes in fair value and settled gains and losses are recorded to regulatory assets or liabilities, and recognized subsequently as gas or fuel costs under regulatory-approved cost recovery mechanisms. For our other derivatives, if they are designated as cash flow hedges, the effective portion 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 is recorded in current earnings.

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 18 of our Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K, we have one benefit pension plan, and several defined post-retirement healthcare plans and non-qualified retirement plans. A Master Trust holds the assets for the Pension Plans. 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 rates, health care cost trend rates, expected return on plan assets, compensation increases, retirement rates and mortality rates. 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 2017 for our non-contributory funded pension plan is expected to be $2.1 million compared to $7.5 million in 2016. The decrease in pension benefit cost is driven by the merging of the three benefit pension plans into one, improved mortality rates and better than expected return on plan assets, partially offset by a decrease in the discount rate.

Beginning in 2016, the Company changed the method used to estimate the service and interest cost components of the net periodic pension, supplemental non-qualified defined benefit and other postretirement benefit costs. The new method used the spot yield curve approach to estimate the service and interest costs by applying the specific spot rates along the yield curve used to determine the benefit obligations to relevant projected cash outflows. Prior to 2016, the service and interest costs were determined using a single weighted-average discount rate based on hypothetical AA Above Median yield curves used to measure the benefit obligation at the beginning of the period. The change does not affect the measurement of the total benefit obligations as the change in service and interest costs offsets the actuarial gains and losses recorded in other comprehensive income.

The Company changed to the new method to provide a more precise measure of service and interest costs by improving the correlation between the projected benefit cash flows and the discrete spot yield curve rates. The Company accounted for this change as a change in estimate prospectively beginning in 2016.

The effect of hypothetical changes to selected assumptions on the pension and other postretirement benefit plans would be as follows in thousands of dollars:

Assumptions	Percentage Change	December 31, 2016 Increase/(Decrease) PBO/APBO [(a)]	2017 Increase/(Decrease) Expense - Pretax
Pension			
Discount rate [(b)]	+/- 0.5	(25,788)/28,367	(2,835)/3,080
Expected return on assets	+/- 0.5	N/A	(1,816)/1,817
OPEB			
Discount rate [(b)]	+/- 0.5	(2,813)/3,051	(29)/59
Expected return on assets	+/- 0.5	N/A	(40)/40
Health care cost trend rate [(b)]	+/- 1.0	2,569/(2,191)	374/(312)

(a) Projected benefit obligation (PBO) for pension plans and accumulated postretirement benefit obligation (APBO) for OPEB plans.
(b) Impact on service cost, interest cost and amortization of gains or losses.

Regulation

Our utility operations are subject to regulation with respect to rates, service area, accounting, and various other matters by state and federal regulatory authorities. The accounting regulations provide that rate-regulated public utilities account for and report assets and liabilities consistent with the economic effects of the manner in which independent third-party regulators establish rates. Regulatory assets generally represent incurred or accrued costs that have been deferred when future recovery from customers is probable. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs.

Management continually assesses the probability of future recoveries and obligations associated with regulatory assets and liabilities. Factors such as the current regulatory environment, recently issued rate orders, and historical precedents are considered. As a result, we believe that the accounting prescribed under rate-based regulation remains appropriate and our regulatory assets are probable of recovery in current rates or in future rate proceedings.

Unbilled Revenue

Revenues attributable to gas and energy delivered to customers, but not yet billed under the cycle billing method, are estimated and accrued and the related costs are charged to expense. Factors influencing the determination of unbilled revenues may include estimates of delivered sales volumes based on weather information and customer consumption trends.

Income Taxes

The Company and its subsidiaries file consolidated federal income tax returns. As a result of the SourceGas transaction, certain acquired subsidiaries file as a separate consolidated group. 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 asset and liability method in accounting for income taxes. Under the asset and 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.

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.

See Note 15 in our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

Business Combinations

We record acquisitions in accordance with ASC 805, Business Combinations, with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition date. The excess of the purchase price over the estimated fair values of the net tangible and net intangible assets acquired is recorded as goodwill. The application of ASC 805, Business Combinations requires management to make significant estimates and assumptions in the determination of the fair value of assets acquired and liabilities assumed in order to properly allocate purchase price consideration between goodwill and assets that are depreciated and amortized. Pertaining to our current year acquisition of SourceGas, substantially all of SourceGas' operations are subject to the rate-setting authority of state regulatory commissions, and are accounted for in accordance with GAAP for regulated operations. SourceGas' assets and liabilities subject to rate setting provisions provide revenues derived from costs, including a return on investment of assets and liabilities included in rate base. As such, the fair value of these assets and liabilities equal their historical net book values.

Our estimates are based on historical experience, information obtained from the management of the acquired companies and, when appropriate, include assistance from independent third-party appraisal firms. These estimates are inherently uncertain and unpredictable. In addition, unanticipated events or circumstances may occur which may affect the accuracy or validity of such estimates. See Note 2 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 their businesses. 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, and anticipated dividends and capital expenditures.

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

Financial Position Summary	2016	2015
Cash and cash equivalents [(a)]	$13,580	$440,861
Restricted cash and equivalents	$2,274	$1,697
Short-term debt, including current maturities of long-term debt	$102,343	$76,800
Long-term debt	$3,211,189	$1,853,682
Stockholders' equity	$1,614,639	$1,465,867
Ratios		
Long-term debt ratio	67%	56%
Total debt ratio	67%	57%

(a) Cash and cash equivalents include the proceeds from the November 23, 2015 issuance of common stock and equity units as discussed below.

As described below in the Debt and Liquidity section, in 2016, we implemented a $750 million, unsecured CP Program that is backstopped by our Revolving Credit Facility, we amended and restated our corporate Revolving Credit Facility to increase total commitments to $750 million from $500 million and extended the term through August 9, 2021 and we entered into a new $500 million term loan expiring August 9, 2019. We completed the permanent financing for the SourceGas Acquisition. In addition to the net proceeds of $536 million from our November 2015 equity issuances, we completed the Acquisition financing with $546 million of net proceeds from our January 2016 debt offering. We also refinanced the long-term debt assumed with the SourceGas Acquisition primarily through $693 million of net proceeds from our August 19, 2016 debt offerings. In addition to our debt refinancings, we issued 1.97 million shares of common stock for approximately $119 million through our ATM equity offering program, and sold a 49.9% noncontrolling interest in Black Hills Colorado IPP for $216 million.

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.

Our Utilities maintain wholesale commodity contracts for the purchases and sales of electricity and natural gas which have performance assurance provisions that allow the counterparty to require collateral postings under certain conditions, including when requested on a reasonable basis due to a deterioration in our financial condition or nonperformance. A significant downgrade in our credit ratings, such as a downgrade to a level below investment grade, could result in counterparties requiring collateral postings under such adequate assurance provisions. The amount of credit support that the Company may be required to provide at any point in the future is dependent on the amount of the initial transaction, changes in the market price, open positions and the amounts owed by or to the counterparty.

In August 2016, we settled $400 million of interest rate swaps, and our remaining interest rate swap expired in January 2017. We currently have no interest rate swap transactions for which we could be required to post collateral on the value of such swaps in the event of an adverse change in our financial condition, including a credit downgrade to below investment-grade.

At December 31, 2016, we had $1.3 million of collateral posted related to our wholesale commodity contracts transactions, and no collateral posted related to our interest rate swap transactions. At December 31, 2016, we had sufficient liquidity to cover any additional collateral that could be required to be posted under these contracts.

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, basis swaps and over-the-counter 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 had a variable interest rate component which can change significantly depending on the economic climate. We deploy hedging strategies that include pay-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations. At December 31, 2016, 86% of our interest rate exposure has been mitigated through either fixed or hedged interest rates.

On January 20, 2016, we executed a 10-year, $150 million notional, forward starting pay fixed interest rate swap at an all-in interest rate of 2.09%, and on October 2, 2015, we executed a 10-year, $250 million notional forward starting pay fixed interest rate swap at an all-in rate of 2.29%, to hedge the risks of interest rate movement between the hedge dates and pricing date for long-term debt refinancings occurring in August 2016. On August 19, 2016, we settled and terminated these interest rate swaps for a loss of $29 million. The loss recorded in AOCI is being amortized over the 10-year life of the associated debt.

At December 31, 2016, we had $50 million notional amount pay-fixed interest rate swap, which expired in January 2017. These swaps were designated as cash flow hedges and accordingly their mark-to-market adjustments were recorded in AOCI on the accompanying Consolidated Balance Sheets. The mark-to-market value of these swaps was a liability of $0.1 million at December 31, 2016.

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 2014. The Protecting Americans from Tax Hikes Act (PATH), enacted into law on December 18, 2015, extended 50% bonus depreciation generally to qualifying property placed in service during 2015 through 2017, 40% bonus depreciation generally to qualifying property placed in service during 2018, and 30% bonus depreciation generally to qualifying property placed in service during 2019. These provisions resulted in approximately $179 million of cash tax benefits for BHC as indicated in the table below:

(in millions)	2016	2015	2014
Tax benefit	$81	$33	$65

In addition, bonus depreciation will apply to qualifying property whose construction and completion period encompasses multiple tax years. The exception being with respect to costs that would be incurred in 2020 when, under current law, bonus depreciation is scheduled to expire. No projects are expected to be subject to this provision. The effect of additional depreciation deductions as a result of bonus depreciation will serve to reduce taxable income and contribute to extending the tax loss carryforwards from being fully utilized until 2021 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 15 of the 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 August 9, 2021, our CP Program 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	2016	2015
Natural Gas Futures and Basis Swaps Pursuant to Utility Commission Approved Hedging Programs	$12,722	$27,659
Oil and Gas Derivatives	2,733	1,672
Total Cash Collateral Positions	$15,455	$29,331

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DEBT

Operating Activities

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

Revolving Credit Facility

On August 9, 2016, we amended and restated our corporate Revolving Credit Facility to increase total commitments to $750 million from $500 million and extend the term through August 9, 2021 with two one-year extension options (subject to consent from the lenders). This facility is similar to the former agreement, which includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents and subject to receipt of additional commitments from existing or new lenders, to increase total commitments of the facility up to $1 billion. 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 either S&P or Moody's for our unsecured debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings, and letters of credit were 0.250%, 1.250%, and 1.250%, respectively, at December 31, 2016. A 0.200% commitment fee is charged on the unused amount of the Revolving Credit Facility.

Our Revolving Credit Facility at December 31, 2016, had the following borrowings, outstanding letters of credit and available capacity (in millions):

Credit Facility	Expiration	Current Capacity	Borrowings at December 31, 2016	Letters of Credit at December 31, 2016	Available Capacity at December 31, 2016
Revolving Credit Facility	August 9, 2021	$ 750	$ 97	$ 36	$ 617

The Revolving Credit Facility contains customary affirmative and negative covenants, such as limitations on certain liens, restrictions on certain transactions, and maintenance of a certain Consolidated Indebtedness to Capitalization Ratio. Under the Revolving Credit Facility, we are required to maintain a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.70 to 1.00 for the quarter ending December 31, 2016 and subsequently for future quarters beginning March 31, 2017, maintain the ratio not to exceed 0.65 to 1.00. Our Consolidated Indebtedness to Capitalization Ratio is calculated by dividing (i) Consolidated Indebtedness, which includes letters of credit, certain guarantees issued and excludes RSNs by (ii) Capital, which includes Consolidated Indebtedness plus Net Worth, which excludes noncontrolling interests in subsidiaries and includes the aggregate outstanding amount of the RSNs. 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, 2016.

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.

On December 22, 2016, we implemented a $750 million, unsecured CP Program that is backstopped by the Revolving Credit Facility. Amounts outstanding under the Revolving Credit Facility and the CP Program, either individually or in the aggregate, cannot exceed $750 million. The notes issued under the CP Program may have maturities not to exceed 397 days from the date of issuance and bear interest (or are sold at par less a discount representing an interest factor) based on, among other things, the size and maturity date of the note, the frequency of the issuance and our credit ratings. Under the CP Program, any borrowings rank equally with our unsecured debt. Notes under the CP Program are not registered and are offered and issued pursuant to an exemption registration. We did not borrow under the CP Program in 2016 and do not have any notes outstanding as of December 31, 2016.

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 and proceeds from our ATM equity offering program.

Recent Financing Transactions

On March 18, 2016, we implemented an ATM equity offering program allowing us to sell shares of our common stock with an aggregate value of up to $200 million. The shares may be offered from time to time pursuant to a sales agreement dated March 18, 2016. Shares of common stock are offered pursuant to our shelf registration statement filed with the SEC. Through December 31, 2016, we have sold and issued an aggregate of 1,968,738 shares of common stock under the ATM equity offering program for $119 million, net of $1.2 million in commissions. As of December 31, 2016, there were no shares sold that were not settled.

On December 22, 2016, we implemented a CP Program as outlined above.

On August 19, 2016, we completed a public debt offering of $700 million principal amount of senior unsecured notes. The debt offering consisted of $400 million of 3.15% 10-year senior notes due January 15, 2027 and $300 million of 4.20% 30-year senior notes due September 15, 2046. Proceeds were used to repay the debt assumed in SourceGas Acquisition which included $95 million senior unsecured notes, $325 million senior unsecured notes and the remaining $100 million of the former $340 million term loan. Additionally, the proceeds were used to pay down $100 million on the term loan issued August 9, 2016 discussed below, and for other corporate uses.

On August 9, 2016, we entered into a $500 million, three-year, unsecured term loan expiring on August 9, 2019. The proceeds of this term loan were used to pay down $240 million of the $340 million unsecured term loan assumed in the SourceGas Acquisition and the $260 million term loan expiring on April 12, 2017.

On August 9, 2016, we amended and restated our corporate Revolving Credit Facility to increase total commitments to $750 million from $500 million and extended the term through August 9, 2021 with two one-year extension options (subject to consent from lenders). This facility is similar to the former agreement, which included an accordion feature that allows us, with the consent of the administrative agent and issuing agents and subject to receipt of additional commitments from existing or new lenders, to increase total commitments of the facility to up to $1 billion. Borrowings continue to be available under a base rate or various Eurodollar rate options.

On June 7, 2016, we entered into a 2.32%, $29 million term loan, due June 7, 2021. Proceeds from this term loan were used to finance the regulatory asset related to the early termination of a gas supply contract (see Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K). Principal and interest are payable quarterly at approximately $1.6 million, the first of which was paid on June 30, 2016.

On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for approximately $216 million. FERC approval of the sale was received on March 29, 2016. We used the proceeds from this sale to pay down borrowings on our revolving credit facility. This sale resulted in an increase to stockholders' equity of approximately $62 million as this sale of a portion of the business that is still controlled is accounted for as an equity transaction and no gain or loss on such sale is recorded.

We completed the following equity and debt transactions in placing permanent financing for SourceGas:

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On January 13, 2016, we completed a public debt offering of $550 million in senior unsecured notes. The debt offering consists of $300 million of 3.95%, 10-year senior notes due 2026, and $250 million of 2.5%, 3-year senior notes due 2019. Net proceeds after discounts and fees were approximately $546 million; and

- On November 23, 2015, we completed the offerings of common stock and equity units. We issued 6.325 million shares of common stock for net proceeds of $246 million and 5.98 million equity units for net proceeds of $290 million. Each equity unit has a stated amount of $50 and consists of a contract to (i) purchase Company common stock and (ii) a 1/20, or 5%, undivided beneficial ownership interest in $1,000 principal amount of remarketable junior subordinated notes due 2028. Pursuant to the purchase contracts, holders are required to purchase Company common stock no later than November 1, 2018.

Our $1.17 billion bridge commitment signed on July 12, 2015 was reduced to $88 million on January 13, 2016, with respect to reductions from our equity and debt offerings. The remaining commitment terminated on February 12, 2016 as part of the closing of the SourceGas Acquisition.

We assumed the following tranches of debt through the SourceGas Acquisition on February 12, 2016; all of which were refinanced in August 2016 as outlined above:

- $325 million, 5.9% senior unsecured notes with an original issue date of April 16, 2007, due April 16, 2017.

- $95 million, 3.98% senior secured notes with an original issue date of September 29, 2014, due September 29, 2019.

- $340 million unsecured corporate term loan due June 30, 2017. Interest expense under this term loan was LIBOR plus a margin of 0.88%.

On January 20, 2016, we executed a 10-year, $150 million notional forward starting pay fixed interest rate swap at an all-in rate of 2.09%, and on October 2, 2015, we executed a 10-year, $250 million notional forward starting pay fixed interest rate swap at an all-in rate of 2.29% to hedge the risks of interest rate movement between the hedge dates and the pricing date for long-term debt refinancings occurring in August 2016. On August 19, 2016, we settled these interest rates swaps for a loss of $29 million. The loss recorded in AOCI is being amortized over the 10 year life of the associated debt.

Future Financing Plans

During the next three years, BHC will evaluate the following financing activities:

- Extending our Revolving Credit Facility;

- Renewing our shelf registration and ATM equity offering program;

- Remarketing junior subordinated notes maturing in 2018;

- Refinancing our term loan maturing in 2019; and

- Paying off our $250 million, 3-year note maturing in 2019.

Cross-Default Provisions

Our $400 million and $24 million corporate term loans contain 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 $50 million or more that permits the acceleration of debt maturities or mandatory debt prepayment. Our Revolving Credit Facility contains the same provisions and a 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

Outside of our ATM equity offering program mentioned above, and based on our current capital spending forecast, we do not anticipate the need to further 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, 2016, we had approximately 53 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, and will be evaluated and approved by our Board of Directors.

On January 25, 2017, our Board of Directors declared a quarterly dividend of $0.445 per share or an annualized equivalent dividend rate of $1.78 per share. The table below provides our historical three-year dividend payout ratio and dividends paid per share:

	2016	2015	2014
Dividend Payout Ratio [(a)]	123%	(228)%	53%
Dividends Per Share	$1.68	$1.62	$1.56

(a) 2016 and 2015 reflect the impacts of non-cash impairments of our Oil and Gas properties totaling $107 million and $250 million, respectively.

Our three-year compound annualized dividend growth rate was 3.4% 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 comply with certain financial or other covenants. At December 31, 2016, our Revolving Credit Facility and Corporate term loans included a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.70 to 1.00, changing to 0.65 to 1.00 in subsequent quarters, beginning March 31, 2017. As of December 31, 2016, we were in compliance with these covenants.

In addition, the agreements governing our equity units generally restrict the payment of cash dividends at any time we have exercised our right to defer payment of contract adjustment payments under the purchase contracts or interest payments under the junior subordinated notes included in such equity units. Moreover, holders of purchase contracts will be entitled to additional shares of our common stock upon settlement of the purchase contracts if we pay regular quarterly dividends in excess of $0.405 per share while the purchase contracts are outstanding. On January 25, 2017, we declared a quarterly dividend of $0.445 per share.

Covenants within Wyoming Electric's financing agreements require Wyoming Electric to maintain a debt to capitalization ratio of no more than .60 to 1.00. Our utilities in Arkansas, 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, 2016, the restricted net assets at our Electric and Gas Utilities were approximately $257 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 (2.213% at December 31, 2016). 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	2016	2015
Black Hills Utility Holdings	$52,370	$98,219
South Dakota Electric	(28,409)	(76,813)
Wyoming Electric	20,737	25,815
Total Money Pool borrowings from Parent	$44,698	$47,221

CASH FLOW ACTIVITIES

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

	2016	2015	2014
Cash provided by (used in)			
Operating activities	$320,463	$424,295	$315,317
Investing activities	$(1,588,742)	$(476,389)	$(401,147)
Financing activities	$840,998	$483,702	$91,067

2016 Compared to 2015

Operating Activities:

Net cash provided by operating activities was $104 million lower than in 2015 primarily attributable to the SourceGas acquisition and the following:

- Cash earnings (income from continuing operations plus non-cash adjustments) were $63 million higher than prior year.

- Net outflow from operating assets and liabilities was $144 million higher than prior year, primarily attributable to:

- Cash inflows decreased by approximately $75 million compared to the prior year as a result of higher materials, supplies and fuel and higher accounts receivable partially due to colder weather and higher natural gas volumes sold;

- Cash inflows decreased by approximately $34 million primarily as a result of changes in our current regulatory assets and liabilities driven by differences in fuel cost adjustments and commodity price impacts compared to the same period in the prior year;

- Cash outflows increased by approximately $35 million as a result of changes in accounts payable and accrued liabilities driven primarily by acquisition and transition costs, and a reduction in uncertain tax positions liability, partially offset by an increase in accrued interest;

- Cash outflows increased by approximately $29 million as a result of interest rate swap settlements;

- Cash outflows increased by $4.0 million due to pension contributions; and

- Cash inflows increased approximately $9.8 million for other operating activities compared to the prior year.

Investing Activities:

Net cash used in investing activities was $1.6 billion in 2016, which was an increase in outflows of $1.1 billion from 2015 primarily due to the following:

- Cash outflows of $1.1 billion for the acquisition of SourceGas, net of $11 million cash received from a working capital adjustment and $760 million of long term debt assumed (see Note 2 in Item 8 of Part II of this Annual Report on Form 10-K);
- In 2016, we had higher capital expenditures of $19 million primarily at our Electric Utilities and Gas Utilities, driven by current year wind and natural gas generation additions at our Electric Utilities, and additional capital at our acquired SourceGas Utilities. This is partially offset by lower current year capital expenditures at our Oil and Gas segment. In 2015 our Oil and Gas segment completed their 2014/2015 Piceance drilling program, while 2016 had no further drilling capital deployed;
- Our Oil and Gas segment divested of non-core assets, selling properties for $11 million; and
- In 2015, we acquired the net assets of two natural gas utilities for $22 million.

Financing Activities:

Net cash provided by financing activities was $841 million in 2016, an increase of $357 million from 2015 primarily due to the following:

- Proceeds of $216 million from the sale of a 49.9% noncontrolling interest of Black Hills Colorado IPP (see Note 12 in Item 8 of Part II of this Annual Report on Form 10-K);
- Long-term borrowings increased due to the $693 million of net proceeds from our August 19, 2016 public debt offering used to refinance the debt assumed in the SourceGas Acquisition, the $500 million of proceeds from our new term loan on August 9, 2016 used to pay off existing debt, the $546 million of net proceeds from our January 13, 2016 public debt offering used to partially finance the SourceGas Acquisition, and proceeds from a $29 million term loan used to fund the early settlement of a gas gathering contract, compared to proceeds of $300 million from long-term borrowings from a term loan in the prior year;
- Payments on long term borrowings increased due to payments made in the current year to refinance the $760 million of long-term debt assumed in the SourceGas Acquisition and $404 million of current year payments made on term loans compared to the payment of $275 million made as part of a term-loan refinancing in the prior year;
- In 2015, we received net proceeds of $290 million from the issuance of our RSNs;
- Proceeds of $120 million primarily from issuing common stock under our ATM equity offering program. 2015 included net proceeds from common stock issuances of $246 million;
- Net short-term borrowings under the revolving credit facility for the year ended December 31, 2016 were $18 million higher than the prior year primarily due to higher working capital requirements in the current year;

- Distributions to noncontrolling interests of $9.6 million;
- Cash outflows for other financing activities increased by approximately $14 million driven primarily by approximately $22 million of financing costs and make whole payments made in 2016 compared to $7 million of bridge facility fees paid in 2015, and
- Cash dividends on common stock of $88 million were paid in 2016 compared to $73 million paid in 2015.

2015 Compared to 2014

Operating Activities:

Net cash provided by operating activities was $109 million higher than in 2014 primarily attributable to:

- Net inflow from operating assets and liabilities of continuing operations was $128 million higher than prior year, primarily attributable to:

- Cash inflows increased by approximately $11 million compared to the prior year as a result of decreased gas volumes in inventory due to milder weather and lower natural gas prices;

- Cash inflows from working capital increased, driven primarily by $52 million as a result of lower customer receivables and by $61 million as a result of lower working capital requirements for natural gas for the year ended December 31, 2015 compared to the prior year. Colder weather and higher natural gas prices during the first quarter 2014 peak winter heating season drove a significant increase in natural gas volumes sold, and in natural gas volumes purchased and fuel cost adjustments recorded in regulatory assets. These fuel cost adjustments deferred in the prior year are recovered through their respective cost mechanisms as allowed by state utility commissions;

- Cash outflows increased approximately $11 million for other operating activities compared to the prior year, primarily by increased benefit plan expenses; and

- Cash earnings (income from continuing operations plus non-cash adjustments) were $9 million lower than prior year.

Investing Activities:

Net cash used in investing activities was $476 million in 2015, which was an increase in outflows of $75 million from 2014 primarily due to the following:

- In 2015, we had higher capital expenditures of $57 million primarily due to our Oil and Gas segment completing the 2014/2015 Piceance drilling program, lower prior year capital affected by weather delays, and increased capital expenditures at our Coal Mine and Gas Utilities. Offsetting these 2015 capital expenditure increases is the construction of Cheyenne Prairie at our Electric Utilities segment occurring in the prior year; and

- In 2015, we acquired the net assets of two natural gas utilities for $22 million.

Financing Activities:

Net cash provided by financing activities was $484 million in 2015, which was an increase in inflow of $393 million from 2014 primarily due to the following:

- Net Long-term borrowings were $315 million in 2015 reflecting a $25 million net increase in our Corporate term loan, and the $290 million issuance of our RSNs, net of issuance costs, compared to net long-term borrowings of $148 million in 2014 when South Dakota Electric and Wyoming Electric sold $160 million of first mortgage bonds in a private placement to provide permanent financing for Cheyenne Prairie and repaid $12 million of South Dakota Electric’s pollution control bonds;

- In 2015, we issued 6.325 million shares of common stock for $246 million, net of issuance costs;

- Net Short-term borrowings under the revolving credit facility were $9.3 million higher than the prior year;

- Cash outflows for other financing activities increased by approximately $26 million driven primarily by $7 million of bridge facility fees paid in 2015, and proceeds of $22 million received in 2014 from the sale of an asset at our Power Generation segment, which under GAAP, this transaction did not qualify as the sale of an asset and the proceeds are presented as a financing activity; and

- Cash dividends on common stock of $73 million were paid in 2015 compared to $70 million paid in 2014.

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 2016, our Electric Utilities' capital expenditures included additional generation from Colorado Electric's Peak View Wind Project and their natural gas CT, 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. We believe that cash generated from operations and borrowing on our CP Program and 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):

	2016	2015	2014
Property additions: [(a)]			
Electric Utilities [(b)]	$258,739	$171,897	$171,475
Gas Utilities [(b)]	173,930	99,674	92,252
Power Generation	4,719	2,694	2,379
Mining	5,709	5,767	6,676
Oil and Gas [(c)]	6,669	168,925	109,439
Corporate	17,353	9,864	9,046
Total expenditures for property, plant and equipment	467,119	458,821	391,267
Common stock dividends	87,570	72,604	69,636
Maturities/redemptions of long-term debt	1,164,308	275,000	12,200
	$1,718,997	$806,425	$473,103

(a) Includes accruals for property, plant and equipment.

(b) Effective January 1, 2016, Cheyenne Light's natural gas utility results are reported in our Gas Utilities segment. Cheyenne Light's gas utility property additions as of the years ended December 31, 2015 and 2014 have been reclassified from the Electric Utilities segment to the Gas Utilities segment. Property additions of $30 million and $22 million, respectively, previously reported in the Electric Utilities segment in 2015 and 2014 are now presented in the Gas Utilities segment.

(c) In 2015, we drilled the last of 13 Mancos Shale wells for our 2014/2015 drilling program. We placed nine on production in 2015. Completion of the four remaining wells was deferred based on the positive results of our nine wells, insufficient gas processing capacity, and continued low commodity prices in 2016.

Forecasted Capital Expenditure Requirements

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

	2017	2018	2019
Electric Utilities	$121,000	$112,000	$139,000
Gas Utilities	179,000	169,000	190,000
Power Generation	2,000	9,000	18,000
Mining	7,000	7,000	8,000
Oil and Gas	3,000	5,000	2,000
Corporate	12,000	3,000	8,000
	$324,000	$305,000	$365,000

We have removed Cost of Service Gas capital expenditures from this forecast due to uncertainties related to the timing of regulatory approvals and other information associated with those approvals, such as the quantity of gas to be provided from a cost of service gas program and whether such gas will be provided from producing reserve purchases or ongoing drilling programs, or both.

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, 2016:

Rating Agency	Senior Unsecured Rating	Outlook
S&P [(a)]	BBB	Stable
Moody’s[(b)]	Baa2	Stable
Fitch [(c)]	BBB+	Negative

(a) On February 12, 2016, S&P reaffirmed BBB rating and maintained a Stable outlook following the closing of the SourceGas Acquisition, reflecting their expectation that management will continue to focus on the core utility operations while maintaining an excellent business risk profile following the acquisition.

(b) On December 9, 2016, Moody’s issued a Baa2 rating with a Stable outlook, which reflects the higher debt leverage resulting from the incremental debt used to fund the SourceGas Acquisition.

(c) On February 12, 2016, Fitch affirmed BBB+ rating and maintained a Negative outlook following the closing of the SourceGas Acquisition, which reflects the initial increased leverage associated with the SourceGas acquisition.

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 South Dakota Electric at December 31, 2016:

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

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, 2016. 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)]	$3,243,261	$5,743	$661,485	$214,178	$2,361,855
Unconditional purchase obligations[(c)]	793,040	163,297	311,290	303,327	15,126
Operating lease obligations[(d)]	27,280	6,739	12,645	3,083	4,813
Other long-term obligations[(e)]	69,639	—	—	—	69,639
Employee benefit plans[(f)]	181,773	16,741	51,074	34,034	79,924
Liability for unrecognized tax benefits in accordance with accounting guidance for uncertain tax positions[(g)]	3,592	—	3,592	—	—
Notes payable	96,600	96,600	—	—	—
Total contractual cash obligations[(h)]	$4,415,185	$289,120	$1,040,086	$554,622	$2,531,357

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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: $126 million in 2017, $126 million in 2018, $121 million in 2019, $113 million in 2020 and $101 million in 2021. Estimated interest payments on variable rate debt are calculated by utilizing the applicable rates as of December 31, 2016.

(c) Unconditional purchase obligations include the energy and capacity costs associated with our PPAs, capacity and certain transmission, gas transportation and storage agreements, and gathering commitments for our Oil and Gas segment. The energy charges under the PPAs are variable costs, which for purposes of estimating our future obligations, were based on costs incurred during 2016 and price assumptions using existing prices at December 31, 2016. Our transmission obligations are based on filed tariffs as of December 31, 2016. 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, Mining and Oil and Gas segments as discussed in Note 8 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) In the first quarter of 2016, we reached a settlement in principle with IRS Appeals in regard to the like-kind exchange transaction associated with the gain deferred from the tax treatment related to the IPP Transaction and the Aquila Transaction. A settlement was also reached with respect to research and development credits and deductions. Both issues were the subject of an IRS Appeals process involving the 2007 to 2009 tax years. See Note 15 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional details.

(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, 2016. 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.

Our Gas Utility segment has commitments to purchase physical quantities of natural gas under contracts indexed to various forward natural gas price curves. In addition, a portion of our gas purchases are purchased under evergreen contracts and therefore, for purposes of this disclosure, are carried out for 60 days. As of December 31, 2016, we are committed to purchase 7.9 million MMBtu, 1.8 million MMBtu, 1.3 million MMBtu, 0.6 million MMBtu and 0.4 million MMBtu in each of the years from 2017 to 2021, respectively.

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, 2016, we had outstanding guarantees as indicated in the table below. For more information on these guarantees, see Note 20 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, 2016	Year Expiring
Indemnification for subsidiary reclamation/surety bonds [(a)]	$ 57,105	Ongoing
	$ 57,105	

(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.

Letters of Credit

Letters of credit reduce the borrowing capacity available on our corporate Revolving Credit Facility. We had $36 million in letters of credit issued under our Revolving Credit Facility at December 31, 2016.

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 of crude oil and natural gas reserves and production, our retail natural gas marketing activities, and our fuel procurement for certain of our gas-fired generation assets; and

- Interest rate risk associated with our variable rate debt as described in Notes 6 and 7 of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

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.

Electric and Gas Utilities

We produce, purchase and distribute power in four states, and purchase and distribute natural gas in six 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 natural gas sold by our Gas Utilities and natural gas used by our Electric Utilities' generation plants or those plants under PPAs where our Electric 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, over-the-counter swaps 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.

For our regulated utilities' hedging plans, 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. When the related costs are recovered through our rates, the hedging activity is recognized in the Consolidated Statements of Income (Loss), or the Consolidated Statements of Comprehensive Income (Loss).

We buy, sell and deliver natural gas at competitive prices by managing commodity price risk. As a result of these activities, this area of our business is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks using over-the-counter and exchange traded options and swaps with counterparties in anticipation of forecasted purchases and/or sales during time frames ranging from January 2017 through April 2019.

The fair value of our Electric and Gas Utilities derivative contracts at December 31 is summarized below (in thousands):

	2016	2015
Net derivative liabilities	$(4,733)	$(22,292)
Cash collateral	12,722	27,659
	$7,989	$5,367

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 from these activities, 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, swaps and options to hedge portions of our crude oil and natural gas production. We elect hedge accounting on the swaps and futures contracts. 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 2017 and 2018 natural gas and crude oil production from the Oil and Gas segment. The hedge agreements in place as of December 31, 2016, are as follows:

Natural Gas

	For the Three Months Ended				
	March 31,	June 30,	September 30,	December 31,	Total Year
2017					
Swaps - MMBtu	810,000	810,000	540,000	540,000	2,700,000
Weighted Average Price per MMBtu	$3.15	$ 3.11	$ 3.04	$ 3.04	$ 3.09

Crude Oil

	For the Three Months Ended				
	March 31,	June 30,	September 30,	December 31,	Total Year
2017					
Swaps - Bbls	18,000	18,000	18,000	18,000	72,000
Weighted Average Price per Bbl	$50.07	$50.85	$ 51.55	$ 52.33	$51.20
Calls - Bbls	9,000	9,000	9,000	9,000	36,000
Weighted Average Price per Bbl	$50.00	$50.00	$ 50.00	$ 50.00	$50.00
2018					
Swaps - Bbls	9,000	9,000	9,000	9,000	36,000
Weighted Average Price per Bbl	$49.58	$49.85	$ 50.12	$ 50.45	$50.00

The fair value of our Oil and Gas segment’s derivative contracts at December 31 is summarized below (in thousands):

	2016	2015
Net derivative asset (liability)	$(1,433)	$10,088
Cash collateral (received) paid	2,733	(8,415)
	$1,300	$1,673

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 pay-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations and anticipated debt refinancings. At December 31, 2016, we had $50 million of notional amount pay-fixed interest rate swap that expired in January 2017. This swap was designated as a cash flow hedge in accordance with accounting standards for derivatives and hedges and accordingly its mark-to-market adjustments were recorded in AOCI on the accompanying Consolidated Balance Sheets.

On January 20, 2016, we executed a 10-year, $150 million notional forward starting pay fixed interest rate swap at an all-in rate of 2.09%, and on October 2, 2015, we executed a 10-year, $250 million notional forward starting pay fixed interest rate swap at an all-in rate of 2.29% to hedge the risks of interest rate movement between the hedge dates and the pricing date for long-term debt refinancings occurring in August 2016. On August 19, 2016, we settled these interest rates swaps for a loss of $29 million. The effective portion in the amount of $28 million was recognized in AOCI and is being amortized over the 10-year life of the associated debt.

Further details of the swap agreements are set forth in Note 9 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

On December 31, 2016 and December 31, 2015, our interest rate swaps and related balances were as follows (dollars in thousands):

	Notional	Weighted Average Fixed Interest Rate	Maximum Terms in Years	Non-current Assets	Current Liabilities, net of Cash Collateral	Non-current Liabilities	Pre-tax AOCI	Pre-tax Unrealized Gain (Loss)
December 31, 2016								
Interest rate swaps	$50,000	4.94 %	0.08 years	$—	$ 90	$ —	$(90)	$ —
	$50,000			$—	$ 90	$ —	$(90)	$ —
December 31, 2015								
Interest rate swaps	$250,000	2.29 %	1.33	$3,441	$ —	$ —	$3,441	$ —
Interest rate swaps	75,000	4.97 %	1.08 years	—	2,835	156	(2,991)	—
	$325,000			$3,441	$ 2,835	$ 156	$450	$ —

Based on December 31, 2016 market interest rates and balances, a loss of approximately $2.9 million would be realized and reported in pre-tax earnings during the next 12 months. This includes the $28 million loss currently deferred in AOCI. 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):

	2017	2018	2019	2020	2021	Thereafter	Total
Long-term debt							
Fixed rate[(a)]	$5,743	$5,743	$255,742	$205,742	$1,436	$2,349,000	$2,823,406
Average interest rate [(b)]	2.32 %	2.32 %	2.5 %	5.78 %	2.32 %	4.29 %	4.23 %
Variable rate	$—	$—	$400,000	$—	$7,000	$12,855	$419,855
Average interest rate [(b)]	— %	— %	1.74 %	— %	0.72 %	0.76 %	1.7 %
Total long-term debt	$5,743	$5,743	$655,742	$205,742	$8,436	$2,361,855	$3,243,261
Average interest rate [(b)]	2.32 %	2.32 %	2.04 %	5.78 %	0.99 %	4.27 %	3.9 %

(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, 2016, our credit exposure included a $1.1 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 2016 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, 2016, based on the criteria set forth in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission “COSO”. 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, 2016.

Our assessment of the effectiveness of our internal controls over financial reporting as of December 31, 2016 excluded the assets and operations acquired on February 12, 2016 in the SourceGas Transaction. SourceGas’ assets and operations constitute approximately 20% of total assets and 22% of sales (excluding SourceGas’ goodwill and intangible assets which were integrated into the Company’s systems and control environment) of the consolidated financial statement amounts as of and for the year ended December 31, 2016. Such exclusion was in accordance with SEC guidance that an assessment of a recently acquired business may be omitted in management’s report on internal control over financial reporting, provided the acquisition took place within twelve months of management’s evaluation.

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, 2016. 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, 2016 and 2015, and the related consolidated statements of income (loss), comprehensive income (loss), equity, and cash flows for each of the three years in the period ended December 31, 2016. 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, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents 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, 2016, 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, 2017 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 24, 2017

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, 2016, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. As described in Management's Report on Internal Control over Financial Reporting, management excluded from its assessment the internal control over financial reporting at Black Hills Gas Holdings, LLC, formerly known as SourceGas Holdings, LLC ("SourceGas"), which was acquired on February 12, 2016, and whose assets and operations constitute approximately 20% of total assets and 22% of sales (excluding SourceGas' goodwill and intangibles which were integrated into the Company's systems and control environment), of the consolidated financial statement amounts as of and for the year ended December 31, 2016. Accordingly, our audit did not include the internal control over financial reporting at SourceGas. 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, 2016, 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, 2016, of the Company and our report dated February 24, 2017, expressed an unqualified opinion on those consolidated financial statements and financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 24, 2017

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME (LOSS)

Year ended	December 31, 2016	December 31, 2015	December 31, 2014
	(in thousands, except per share amounts)		
Revenue	$1,572,974	$1,304,605	$1,393,570
Operating expenses:			
Fuel, purchased power and cost of natural gas sold	499,132	456,887	581,782
Operations and maintenance	456,399	361,109	359,095
Depreciation, depletion and amortization	189,043	155,370	144,745
Impairment of long-lived assets	106,957	249,608	—
Taxes - property, production and severance	48,522	44,353	43,580
Other operating expenses	50,335	7,483	500
Total operating expenses	1,350,388	1,274,810	1,129,702
Operating income	222,586	29,795	263,868
Other income (expense):			
Interest charges -			
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts)	(139,590)	(86,278)	(73,017)
Allowance for funds used during construction - borrowed	2,981	1,250	1,075
Capitalized interest	1,197	1,309	982
Interest income	1,429	1,621	1,925
Allowance for funds used during construction - equity	3,270	897	994
Other expense	(609)	(372)	(377)
Other income	1,842	2,256	2,065
Total other income (expense)	(129,480)	(79,317)	(66,353)
Income (loss) before earnings (loss) of unconsolidated subsidiaries and income taxes	93,106	(49,522)	197,515
Equity in earnings (loss) of unconsolidated subsidiaries	—	(344)	(1)
Impairment of equity investments	—	(4,405)	—
Income tax benefit (expense)	(10,475)	22,160	(66,625)
Net income (loss)	82,631	(32,111)	130,889
Net income attributable to noncontrolling interest	(9,661)	—	—
Net income (loss) available for common stock	$72,970	$(32,111)	$130,889
Earnings (loss) per share of common stock:			
Earnings (loss) per share, Basic	$1.41	$(0.71)	$2.95
Earnings (loss) per share, Diluted	$1.37	$(0.71)	$2.93
Weighted average common shares outstanding:			
Basic	51,922	45,288	44,394
Diluted	53,271	45,288	44,598

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

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BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

Year ended	December 31, 2016	December 31, 2015	December 31, 2014
	(in thousands)		
Net income (loss)	$82,631	$(32,111)	$130,889
Other comprehensive income (loss), net of tax:			
Benefit plan liability adjustments - net gain (loss) (net of tax of $757, $(1,375) and $5,004, respectively)	(1,738)	2,657	(10,590)
Benefit plan liability adjustments - prior service (costs) (net of tax of $107, $0 and $(17), respectively)	(247)	—	237
Reclassification adjustment of benefit plan liability - net gain (loss) (net of tax of $(600), $(972) and $(348), respectively)	1,378	1,850	646
Reclassification adjustment of benefit plan liability - prior service cost (net of tax of $67, $88 and $76, respectively)	(154)	(150)	(141)
Derivative instruments designated as cash flow hedges:			
Net unrealized gains (losses) on interest rate swaps (net of tax of $10,920, $(598) and $186, respectively)	(20,302)	2,290	(350)
Reclassification of net realized (gains) losses on settled/amortized interest rate swaps (net of tax of $(1,365), $(1,348) and $(1,356), respectively)	2,534	2,299	2,313
Net unrealized gains (losses) on commodity derivatives (net of tax of $212, $(3,898) and $(5,425), respectively)	(361)	5,884	9,256
Reclassification of net realized (gains) losses on settled commodity derivatives (net of tax of $4,067, $5,619 and $(988), respectively)	(6,938)	(8,841)	1,007
Other comprehensive income (loss), net of tax	(25,828)	5,989	2,378
Comprehensive income (loss)	56,803	(26,122)	133,267
Less: comprehensive income attributable to non-controlling interest	(9,661)	—	—
Comprehensive income (loss) available for common stock	$47,142	$(26,122)	$133,267

See Note 16 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, 2016	December 31, 2015
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$13,580	$440,861
Restricted cash and equivalents	2,274	1,697
Accounts receivable, net	263,289	147,486
Materials, supplies and fuel	107,210	86,943
Derivative assets, current	4,138	—
Income tax receivable, net	—	368
Regulatory assets, current	49,260	57,359
Other current assets	27,063	71,763
Total current assets	466,814	806,477
Investments	12,561	11,985
Property, plant and equipment	6,412,223	4,976,778
Less accumulated depreciation and depletion	(1,943,234)	(1,717,684)
Total property, plant and equipment, net	4,468,989	3,259,094
Other assets:		
Goodwill	1,299,454	359,759
Intangible assets, net	8,392	3,380
Derivative assets, non-current	222	3,441
Regulatory assets, non-current	246,882	175,125
Other assets, non-current	12,130	7,382
Total other assets, non-current	1,567,080	549,087
TOTAL ASSETS	$6,515,444	$4,626,643

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, 2016	December 31, 2015
	(in thousands, except share amounts)	
LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND EQUITY		
Current liabilities:		
Accounts payable	$153,477	$89,794
Accrued liabilities	244,034	232,061
Derivative liabilities, current	2,459	2,835
Accrued income tax, net	12,552	—
Regulatory liabilities, current	13,067	4,865
Notes payable	96,600	76,800
Current maturities of long-term debt	5,743	—
Total current liabilities	527,932	406,355
Long-term debt, net of current maturities	3,211,189	1,853,682
Deferred credits and other liabilities:		
Deferred income tax liabilities, net, non-current	535,606	450,579
Derivative liabilities, non-current	274	156
Regulatory liabilities, non-current	193,689	148,176
Benefit plan liabilities	173,682	146,459
Other deferred credits and other liabilities	138,643	155,369
Total deferred credits and other liabilities	1,041,894	900,739
Commitments and contingencies (See Notes 6, 7, 8, 9, 14, 18, 19, and 20)		
Redeemable noncontrolling interest	4,295	—
Equity:		
Stockholders’ equity -		
Common stock $1 par value; 100,000,000 shares authorized; issued: 53,397,467 and 51,231,861 shares, respectively	53,397	51,232
Additional paid-in capital	1,138,982	953,044
Retained earnings	457,934	472,534
Treasury stock at cost - 15,258 and 39,720 shares, respectively	(791)	(1,888)
Accumulated other comprehensive income (loss)	(34,883)	(9,055)
Total stockholders’ equity	1,614,639	1,465,867
Noncontrolling interest	115,495	—
Total equity	1,730,134	1,465,867
TOTAL LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND TOTAL EQUITY	$6,515,444	$4,626,643

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, 2016	December 31, 2015	December 31, 2014
	(in thousands)		
Operating activities:			
Net income (loss)	$82,631	$(32,111)	$130,889
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	189,043	155,370	144,745
Deferred financing cost amortization	6,180	6,364	2,127
Impairment of long-lived assets and equity method investments	106,957	254,013	—
Stock compensation	10,885	4,076	9,329
Deferred income taxes	36,217	(26,028)	70,232
Employee benefit plans	14,291	20,616	14,814
Other adjustments, net	(5,518)	(4,872)	14,415
Change in certain operating assets and liabilities:			
Materials, supplies and fuel	1,099	7,197	(4,563)
Accounts receivable, unbilled revenues and other current assets	(28,414)	40,125	(18,684)
Accounts payable and other current liabilities	(40,195)	(4,779)	7,887
Regulatory assets	3,614	21,883	(38,774)
Regulatory liabilities	(14,082)	1,675	(7,633)
Contributions to defined benefit pension plans	(14,200)	(10,200)	(10,200)
Interest rate swap settlement	(28,820)	—	—
Other operating activities, net	775	(9,034)	733
Net cash provided by operating activities	320,463	424,295	315,317
Investing activities:			
Property, plant and equipment additions	(474,783)	(455,481)	(398,494)
Acquisition of net assets, net of long-term debt assumed	(1,124,238)	(21,970)	—
Proceeds from sale of assets	11,418	—	—
Other investing activities	(1,139)	1,062	(2,653)
Net cash provided by (used in) investing activities	(1,588,742)	(476,389)	(401,147)
Financing activities:			
Dividends paid on common stock	(87,570)	(72,604)	(69,636)
Common stock issued	121,619	248,759	3,251
Short-term borrowings - issuances	425,400	397,310	396,250
Short-term borrowings - repayments	(405,600)	(395,510)	(403,750)
Long-term debt - issuance	1,767,608	300,000	160,000
Long-term debt - repayments	(1,164,308)	(275,000)	(12,200)
Sale of noncontrolling interest	216,370	—	—
Distributions to noncontrolling interests	(9,561)	—	—
Equity units - issuance	—	290,030	—
Other financing activities	(22,960)	(9,283)	17,152
Net cash provided by (used in) financing activities	840,998	483,702	91,067
Net change in cash and cash equivalents	(427,281)	431,608	5,237
Cash and cash equivalents beginning of year	440,861	9,253	4,016

Cash and cash equivalents end of year	$13,580	$440,861	$9,253

See Note 17 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 EQUITY

	Common Stock		Treasury Stock						
(in thousands except share amounts)	Shares	Value	Shares	Value	Additional Paid in Capital	Retained Earnings	AOCI	Non controlling Interest	Total
Balance at December 31, 2013	44,550,239	$44,550	50,877	$(1,968)	$742,344	$515,996	$(17,422)	$—	$1,283,500
Net income (loss) available for common stock	—	—	—	—	—	130,889	—	—	130,889
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	$577,249	$(15,044)	$—	$1,353,884
Net income (loss) available for common stock	—	—	—	—	—	(32,111)	—	—	(32,111)
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	5,989	—	5,989
Dividends on common stock	—	—	—	—	—	(72,604)	—	—	(72,604)
Share-based compensation	126,765	127	(2,506)	(13)	4,126	—	—	—	4,240
Issuance of common stock	6,325,000	6,325	—	—	248,256	—	—	—	254,581
Issuance costs	—	—	—	—	(17,926)	—	—	—	(17,926)
Premium on Equity Units	—	—	—	—	(33,118)	—	—	—	(33,118)
Dividend reinvestment and stock purchase plan	66,024	66	—	—	2,891	—	—	—	2,957
Other stock transactions	—	—	—	—	(25)	—	—	—	(25)

Balance at December 31, 2015	51,231,861	$51,232	39,720	$(1,888)	$953,044	$472,534	$(9,055)	$—	$1,465,867
Net income (loss) available for common stock	—	—	—	—	—	72,970	—	9,661	82,631
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	(25,828)	—	(25,828)
Dividends on common stock	—	—	—	—	—	(87,570)	—	—	(87,570)
Share-based compensation	145,634	146	(16,165)	668	4,665	—	—	—	5,479
Issuance of common stock	1,968,738	1,969	—	—	118,021	—	—	—	119,990
Issuance costs	—	—	—	—	(1,566)	—	—	—	(1,566)
Dividend reinvestment and stock purchase plan	51,234	50	—	—	2,933	—	—	—	2,983
Other stock transactions	—	—	(8,297)	429	47	—	—	—	476
Sale of noncontrolling interest	—	—	—	—	61,838	—	—	115,395	177,233
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(9,561)	(9,561)
Balance at December 31, 2016	53,397,467	$53,397	15,258	$(791)	$1,138,982	$457,934	$(34,883)	$115,495	$1,730,134

Dividends per share paid were $1.68, $1.62 and $1.56 for the years ended December 31, 2016, 2015 and 2014, respectively.

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

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BLACK HILLS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2016, 2015 and 2014

(1) BUSINESS DESCRIPTION AND SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Corporation is a customer-focused, growth-oriented, vertically-integrated utility company headquartered in Rapid City, South Dakota. We are a holding company that, through our subsidiaries, conducts our operations through the following reportable segments: Electric Utilities, Gas Utilities, Power Generation, Mining, and Oil and Gas.

Segment Reporting

Our reportable segments are based on our method of internal reporting, which is generally segregated by differences in products, services and regulation. All of our operations and assets are located within the United States. Prior to 2016, our segments were reported within two business groups, our Utilities Group, containing the Electric Utilities and Gas Utilities segments, and our Non-regulated Energy Group, containing the Power Generation, Mining and Oil and Gas segments. We have continued to report our operations consistently through our reportable segments. However, we will no longer separate the segments by business group.

Our Electric Utilities segment includes the operating results of the regulated electric utility operations of South Dakota Electric, Wyoming Electric and Colorado Electric, which supply regulated electric utility services to areas in South Dakota, Wyoming, Colorado and Montana. Our Gas Utilities Segment consists of the operating results of our regulated natural gas utility subsidiaries in Arkansas, Colorado, Iowa, Kansas, Wyoming and Nebraska.

All of our non-utility business segments support our electric utilities, other than the Oil and Gas segment. Our Power Generation segment, which is conducted through Black Hills Electric Generation and its subsidiaries, engages in independent power generation activities in Wyoming and Colorado. Our Mining segment, which is conducted through WRDC, engages in coal mining activities located near Gillette, Wyoming. Our Oil and Gas segment, 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. Our Oil and Gas segment's focus is on cost of service gas programs. We are divesting non-core oil and gas assets while retaining those best suited for a cost of service gas program and have refocused our professional staff on assisting our utilities with the implementation of a Cost of Service Gas Program.

For further descriptions of our reportable business segments, see Note 5.

The following changes have been made to our Consolidated Statements of Income (Loss) to reflect combined revenue and combined operations and maintenance expenses, rather than by business group as previously reported, for the twelve months ended December 31, 2015 and December 31, 2014 respectively:

	Year Ended December 31, 2015			Year Ended December 31, 2014		
(in thousands)	As Previously Reported	Presentation Reclassification	As Currently Reported	As Previously Reported	Presentation Reclassification	As Currently Reported
Revenue:						
Utilities	$1,219,526	$(1,219,526)	$—	$1,300,969	$(1,300,969)	$—
Non-regulated energy	$85,079	$(85,079)	$—	$92,601	$(92,601)	$—

Revenue	$—	$ 1,304,605	$1,304,605	$—	$ 1,393,570	$1,393,570
Operating Expenses:						
Utilities - operations and maintenance	$272,407	$ (272,407)	$—	$270,954	$ (270,954)	$—
Non-regulated energy operations and maintenance	$88,702	$ (88,702)	$—	$88,141	$ (88,141)	$—
Operations and maintenance	$—	$ 361,109	$361,109	$—	$ 359,095	$359,095

This presentation reclassification did not impact our consolidated financial position, results of operations or cash flows.

Segment Reporting Transition of Cheyenne Light's Natural Gas Distribution

Effective January 1, 2016, the natural gas operations of Cheyenne Light have been included in our Gas Utilities Segment. Through December 31, 2015, Cheyenne Light's natural gas operations were included in our Electric Utilities Segment as these natural gas operations were consolidated within Cheyenne Light since its acquisition. This change is a result of our business segment reorganization to, among other things, integrate all regulated natural gas operations, including the SourceGas Acquisition, into our Gas Utilities Segment which is led by the Group Vice President, Natural Gas Utilities. Likewise, all regulated electric utility operations, including Cheyenne Light's electric utility operations, are reported in our Electric Utilities Segment, which is led by the Group Vice President, Electric Utilities. The prior periods have been reclassified to reflect this change in presentation between the Electric Utilities and Gas Utilities segments. See Note 5 for Revenues and Net Income amounts reclassified from the Electric Utilities segment to the Gas Utilities segment for the twelve months ended December 31, 2015 and December 31, 2014; and Segment Assets reclassified from the Electric Utilities segment to the Gas Utilities segment for the twelve months ended December 31, 2015. This segment reclassification did not impact our consolidated financial position, results of operations or cash flows.

Revisions

Certain revisions have been made to prior years' financial information to conform to the current year presentation. The Company revised its presentation of cash and book overdrafts. For accounts with the same financial institution where there is a banking arrangement that clears payments with balances in other bank accounts, book overdrafts are presented on a combined basis by bank as cash and cash equivalents. Prior year amounts were corrected to conform with the current year presentation, which decreased cash and cash equivalents and accounts payable by $16 million, $12 million and $3.8 million as of December 31, 2015, December 31, 2014 and December 31, 2013, respectively, and decreased net cash flows provided by operations by $3.7 million and $8.1 million for the years ended December 31, 2015 and 2014 respectively. We assessed the materiality of these changes, taking into account quantitative and qualitative factors, and determined them to be immaterial to the consolidated balance sheet as of December 31, 2015 and to the consolidated statements of cash flows for the years ended December 31, 2015 and 2014. There is no impact to the Consolidated Statements of Income (Loss), the Consolidated Statements of Comprehensive Income (Loss) or the Consolidated Statements of Equity, for any period reported.

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 5.

Our Consolidated Statements of Income (Loss) 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 4 for additional information.

Variable Interest Entities

We evaluate arrangements and contracts with other entities to determine if they are VIEs and if so, if we are the primary beneficiary. GAAP provides a framework for identifying VIEs and determining when a company should include the assets, liabilities, noncontrolling interest and results of activities of a VIE in its consolidated financial statements.

A VIE should be consolidated if a party with an ownership, contractual or other financial interest in the VIE (a variable interest holder) has the power to direct the VIEs most significant activities and the obligation to absorb losses or right to receive benefits of the VIE that could be significant to the VIE. A variable interest holder that consolidates the VIE is called the primary beneficiary. Upon consolidation, the primary beneficiary generally must initially record all of the VIE’s assets, liabilities and noncontrolling interests at fair value and subsequently account for the VIE as if it were consolidated.

Our evaluation of whether it qualifies as the primary beneficiary of a VIE involves significant judgments, estimates and assumptions and includes a qualitative analysis of the activities that most significantly impact the VIE’s economic performance and whether the Company has the power to direct those activities, the design of the entity, the rights of the parties and the purpose of the arrangement. Black Hills Colorado IPP is a VIE. See additional information in Note 12.

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 Electric and Gas Utilities business segments 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 estimated unbilled amounts net of write-offs and allowance for doubtful accounts. Accounts receivable for our Mining, Oil and Gas, and Power Generation business segments 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 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):

2016	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 41,730	$ 36,463	$ (353)	$ 77,840
Gas Utilities	88,168	88,329	(2,026)	174,471
Power Generation	1,420	—	—	1,420
Mining	3,352	—	—	3,352
Oil and Gas	3,991	—	(13)	3,978
Corporate	2,228	—	—	2,228
Total	$ 140,889	$ 124,792	$ (2,392)	$ 263,289

2015	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities [(a)]	$ 41,679	$ 35,874	$ (727)	$ 76,826
Gas Utilities [(a)]	30,330	32,869	(1,001)	62,198
Power Generation	1,187	—	—	1,187
Mining	2,760	—	—	2,760
Oil and Gas	3,502	—	(13)	3,489
Corporate	1,026	—	—	1,026
Total	$ 80,484	$ 68,743	$ (1,741)	$ 147,486

(a) Effective January 1, 2016, Cheyenne Light's natural gas utility results are reported in our Gas Utilities segment. Cheyenne Light's gas utility accounts receivable has been reclassified from the Electric Utilities segment to the Gas Utilities segment. Accounts receivable of $6.8 million as of December 31, 2015, previously reported in the Electric Utilities segment is now presented in the Gas Utilities segment.

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 and franchise taxes 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, 2016	December 31, 2015
Materials and supplies	$ 68,456	$ 55,726
Fuel - Electric Utilities	3,667	5,567
Natural gas in storage	35,087	25,650
Total materials, supplies and fuel	$ 107,210	$ 86,943

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.

Accrued Liabilities

The following amounts by major classification are included in Accrued liabilities on the accompanying Consolidated Balance Sheets as of (in thousands):

	December 31, 2016	December 31, 2015
Accrued employee compensation, benefits and withholdings	$ 56,926	$ 43,342
Accrued property taxes	40,004	32,393
Accrued payments related to litigation expenses and settlements	—	38,750
Customer deposits and prepayments	51,628	53,496
Accrued interest and contract adjustment payments	45,503	25,762
Other (none of which is individually significant)	49,973	38,318
Total accrued liabilities	$ 244,034	$ 232,061

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. We also classify our base or “cushion gas” as property, plant and equipment. Cushion gas is the portion of natural gas necessary to force saleable gas from a storage field into the transmission system and for system balancing, representing a permanent investment necessary to use storage facilities and maintain reliability.

The cost of regulated utility property, plant and equipment retired, or otherwise disposed of in the ordinary course of business, less salvage plus retirement costs, 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, depreciation is computed on a unit-of-production methodology based on plant hours run.

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.

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 non-cash ceiling test impairments of oil and gas long-lived assets included in the Oil and Gas segment in 2016 and 2015. No ceiling test write-down was recorded in 2014. See Note 13 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 have no PUDs at December 31, 2016. See information on our oil and gas drilling activities in Note 21.

Companies are permitted but not required to disclose probable and possible reserves. We have elected not to report 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 a goodwill impairment test on an annual basis or upon the occurrence of events or changes in circumstances that indicate that the asset might be impaired. Beginning in 2016, we changed our annual goodwill impairment testing date from November 30 to October 1 to better align the testing date with our financial planning process. We believe that the change in the date of the annual goodwill impairment test from November 30 to October 1 is not a material change in the application of an accounting principle. The new and old testing dates are close in proximity; both are in the fourth quarter of the year, and our current testing date is within ten months of the most recent impairment testing. We would not expect a materially different outcome as a result of testing on October 1 as compared to November 30. The change in assessment date does not have a material effect on the financial statements.

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.

The Company has determined that the reporting units for its goodwill impairment test are its operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which segment management regularly reviews the operating results. See Note 5 for additional business segment information.

Goodwill at our Electric utilities primarily arose from Colorado Electric, acquired in the Aquila acquisition, which allocated approximately $246 million, or 72% of the transaction to Colorado Electric. Goodwill at our Gas Utilities is primarily from the SourceGas Acquisition, which was allocated entirely to the Gas Utilities adding $940 million in goodwill and the Aquila Transaction, which allocated approximately $94 million, or 28% of the transaction, to the Gas Utilities.

We believe that the goodwill reflects the inherent value of the relatively stable, long-lived cash flows of the regulated electric and gas utility businesses, considering the regulatory environment, and the long-lived cash flow and rate base growth opportunities at our utilities. Goodwill balances were as follows (in thousands):

	Electric Utilities [a]	Gas Utilities [a]	Power Generation	Total
Ending balance at December 31, 2014	$248,479	$96,152	$ 8,765	$353,396
Additions [b]	—	6,363	—	6,363
Ending balance at December 31, 2015	$248,479	$102,515	$ 8,765	$359,759
Additions [c]	—	939,695	—	939,695
Ending balance at December 31, 2016	$248,479	$1,042,210	$ 8,765	$1,299,454

(a) Goodwill of $2.0 million and $6.3 million for December 31, 2014 and December 31, 2015, respectively, is now presented in the Gas Utilities segment as a result of the inclusion of Cheyenne Light's Gas operations in the Gas Utilities segment, previously reported in the Electric Utilities segment. See above in this Note 1 for additional details.

(b) Goodwill was recorded on the July 1, 2015 acquisition of Wyoming natural gas utility Energy West Wyoming, Inc., and natural gas pipeline assets from Energy West Development, Inc.

(c) Represents goodwill recorded with the acquisition of SourceGas. See Note 2 for more information.

Our intangible assets represent easements, rights-of-way, customer listings, and trademarks and are amortized using a straight-line method based on estimated useful lives. The finite lived intangible assets are currently being amortized from 2 years up to 40 years. Changes to intangible assets for the years ended December 31, were as follows (in thousands):

	2016	2015	2014
Intangible assets, net, beginning balance	$3,380	$3,176	$3,397
Additions	5,522	434	—
Amortization expense [a]	(510)	(230)	(221)
Intangible assets, net, ending balance	$8,392	$3,380	$3,176

(a) Amortization expense for existing intangible assets is expected to be $0.8 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 (Loss). 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 8.

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.

Electric Utilities and Gas Utilities Segments:

- The commodity contracts for the Utilities, valued using the market approach, include exchange-traded futures, options, basis swaps and over-the-counter swaps (Level 2) for natural gas contracts. For exchanged-traded futures, options and basis swap Level 2 assets and liabilities, fair value was derived using broker quotes validated by the Chicago Mercantile Exchange pricing for similar instruments. For over-the-counter swaps and option Level 2 assets and liabilities, fair value was derived from, or corroborated by, observable market data where market data for pricing is observable. In addition, the fair value for the over-the-counter swaps and option derivatives include a CVA component. The CVA considers the fair value of the derivative 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.

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. Our remaining interest rate swap as of December 31, 2016 expired in January 2017.

Additional information is included in Note 10.

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, or 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 electric and gas utility 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 (Loss).

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 Electric Utilities and Gas Utilities follow accounting standards for regulated operations and reflect 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, 2016	As of December 31, 2015
Regulatory assets			
Deferred energy and fuel cost adjustments - current [(a)(d)]	1	$17,491	$24,751
Deferred gas cost adjustments [(a)(d)]	1	15,329	15,521
Gas price derivatives [(a)]	4	8,843	23,583
Deferred taxes on AFUDC [(b)]	45	15,227	12,870
Employee benefit plans [(c) (e)]	12	108,556	83,986
Environmental [(a)]	subject to approval	1,108	1,180
Asset retirement obligations [(a)]	44	505	457
Loss on reacquired debt [(a)]	22	20,188	3,133
Renewable energy standard adjustment [(a)]	5	1,605	5,068
Deferred taxes on flow through accounting [(c)]	35	37,498	29,722
Decommissioning costs [(b)]	10	16,859	18,310
Gas supply contract termination [(a)]	5	26,666	—
Other regulatory assets [(a)]	15	26,267	13,903
		$296,142	$232,484
Regulatory liabilities			
Deferred energy and gas costs [(a)]	1	$10,368	$7,814
Employee benefit plans [(c)]	12	68,654	47,218
Cost of removal [(a)]	44	118,410	90,045
Other regulatory liabilities [(c)]	25	9,324	7,964
		$206,756	$153,041

(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. 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) Increase compared to 2015 was driven by the addition of the SourceGas employee benefit plans.

Regulatory assets represent items we expect to recover from customers through probable future rates.

Deferred Energy and Fuel Cost Adjustments - Current - 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 4-year term represents the maximum forward term hedged.

Deferred Taxes on 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 AOCI, including costs being amortized from the Aquila Transaction.

Environmental - Environmental expenditures are costs 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 8 for additional details.

Loss on Reacquired Debt - Loss on reacquired debt is 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.

Deferred Taxes on 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. 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 currently deductible for tax purposes, but are capitalized for book purposes.

Decommissioning Costs - South Dakota Electric and Colorado Electric received approval in 2014 for recovery of the remaining net book values and decommissioning costs of their decommissioned coal plants. South Dakota Electric is allowed a return on their costs, in addition to recovery of those costs.

Gas Supply Contract Termination - Black Hills Gas Holdings had agreements under the previous ownership that required the Company to purchase all of the natural gas produced over the productive life of specific leaseholds in the Bowdoin Field in Montana. The majority of these purchases were committed to distribution customers in Nebraska, Colorado, and Wyoming, which are subject to cost recovery mechanisms. The prices to be paid under these agreements varied, ranging from $6 to $8 per MMBtu at the time of acquisition, and exceeded market prices. We recorded a liability for this contract in our purchase price allocation. We were granted approval to terminate these agreements from the NPSC, CPUC and WPSC, on the basis that these agreements are not beneficial to customers over the long term. We received written orders allowing us to create a regulatory asset for the net buyout costs associated with the contract termination, and recover the majority of costs from customers over a period of five years. We terminated the contract and settled the liability on April 29, 2016.

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. As a result of the SourceGas transaction, certain subsidiaries acquired file as a separate consolidated group. Where applicable, 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 asset and liability method in accounting for income taxes. Under the asset and 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.

It is our policy to apply the flow-through method of accounting for investment tax credits. 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. An exception to this general policy is the deferral method, which applies to our regulated businesses. Such a method results in the investment tax credit being amortized as a reduction to income tax expense over the estimated useful lives of the underlying property that generated the credit.

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 (Loss).

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 15 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 equity units, and 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, 2016	December 31, 2015	December 31, 2014
Net income (loss) available for common stock	$ 72,970	$ (32,111)	$ 130,889
Weighted average shares - basic	51,922	45,288	44,394
Dilutive effect of:			
Equity Units	1,222	—	—
Equity compensation	127	—	204
Weighted average shares - diluted	53,271	45,288	44,598
Net income (loss) available for common stock, per share - Diluted	$ 1.37	$ (0.71)	$ 2.93

Due to our Net loss available for common stock for the year ended December 31, 2015, potentially diluted securities were excluded from the diluted loss per share calculation due to their anti-dilutive effect. In computing diluted net loss per share, 83,000 equity compensation shares were excluded from the computation for the year ended December 31, 2015.

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, 2016	December 31, 2015	December 31, 2014
Equity compensation	3	112	81
Equity units	—	6,440	—
Anti-dilutive shares excluded from computation of earnings (loss) per share	3	6,552	81

Business Combinations

We record acquisitions in accordance with ASC 805, Business Combinations, with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition date. The excess of the purchase price over the estimated fair values of the net tangible and net intangible assets acquired is recorded as goodwill. The application of ASC 805, Business Combinations requires management to make significant estimates and assumptions in the determination of the fair value of assets acquired and liabilities assumed in order to properly allocate purchase price consideration between goodwill and assets that are depreciated and amortized. Our estimates are based on historical experience, information obtained from the management of the acquired companies and, when appropriate, include assistance from independent third-party appraisal firms. These estimates are inherently uncertain and unpredictable. In addition, unanticipated events or circumstances may occur which may affect the accuracy or validity of such estimates. See Note 2 for additional detail on the accounting for the SourceGas Acquisition.

Noncontrolling Interest

We account for changes in our controlling interests of subsidiaries according to ASC 810, Consolidations. ASC 810 requires that the Company record such changes as equity transactions, recording no gain or loss on such a sale. GAAP requires that noncontrolling interests in subsidiaries and affiliates be reported in the equity section of a company's balance sheet. In addition, the amounts attributable to the noncontrolling interest net income (loss) of those subsidiaries are reported separately in the consolidated statements of income and comprehensive income. See Note 12 for additional detail on Noncontrolling Interests.

Share-Based Compensation

We account for our share-based compensation arrangements in accordance with ASC 718, Compensation-Stock Compensation, by recognizing compensation costs for all share-based awards over the respective service period for employee services received in exchange for an award of equity or equity-based compensation. Awards that will be settled in stock are accounted for as equity and the compensation expense is based on the grant date fair value. Awards that are settled in cash are accounted for as liabilities and the compensation expense is re-measured each period based on the current market price and performance achievement measures.

Recently Issued and Adopted Accounting Standards

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments, ASU 2016-15

In August 2016, the FASB issued ASU 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments (a consensus of the Emerging Issues Task Force). This ASU requires changes in the presentation of certain items including but not limited to debt prepayment or debt extinguishment costs; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies and distributions received from equity method investees. The ASU will be effective for fiscal years beginning after December 15, 2017. We will use the retrospective transition method to adopt this standard with fiscal years beginning after December 15, 2017. This standard will not have a material impact on our financial position, results of operations or cash flows.

Improvements to Employee Share-Based Payment Accounting, ASU 2016-09

In March 2016, the FASB issued ASU 2016-09, Improvements to Employee Share-Based Payment Accounting. This ASU simplifies several aspects of the accounting for employee share-based payment transactions, including the accounting for forfeitures, income taxes, and statutory tax withholding requirements. The ASU will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2016, with early adoption permitted. Certain amendments of this guidance are to be applied retrospectively and others prospectively. We will adopt this standard for fiscal years, and interim periods within those years, beginning after December 15, 2016. The adoption of this standard will not have a material impact on our financial position, results of operations or cash flows.

Leases, ASU 2016-02

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), which supersedes ASC 840, Leases. This ASU requires lessees to recognize a right-of-use asset and lease liability on the balance sheet for all leases with terms of more than 12 months. Lessees are permitted to make an accounting policy election to not recognize the asset and liability for leases with a term of 12 months or less. The ASU does not significantly change the lessees' recognition, measurement and presentation of expenses and cash flows from the previous accounting standard. Lessors' accounting under the ASU is largely unchanged from the previous accounting standard. In addition, the ASU expands the disclosure requirements of lease arrangements. Lessees and lessors will use a modified retrospective transition approach, which includes a number of practical expedients. The guidance is effective for the Company beginning after December 15, 2018. Early adoption is permitted. We are currently assessing the impact that adoption of ASU 2016-02 will have on our financial position, results of operations or cash flows.

Simplifying the Accounting for Measurement-Period Adjustments, ASU 2015-16

In September 2015, the FASB issued ASU 2015-16, Simplifying the Accounting for Measurement-Period Adjustments. This ASU eliminates the requirement to retrospectively account for changes to provisional amounts recognized at the acquisition date in a business combination. ASU 2015-16 requires that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustments are determined, including the effect of the change in the provisional amount as if the accounting had been completed at the acquisition date. The provisions of this ASU are effective for fiscal years beginning after December 31, 2015, including interim periods within those fiscal years and should be applied prospectively to adjustments to provisional amounts that occur after the effective date. We have implemented ASU 2015-16 as of January 1, 2016. Adoption of this standard did not have a material impact on our financial position, results of operations or cash flows.

Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or its Equivalent), ASU 2015-07

On May 1, 2015, the FASB issued ASU 2015-07, Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or its Equivalent). The ASU removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient and also removes certain disclosure requirements. The new requirements were effective for us beginning January 1, 2016 and were applied retrospectively to all periods presented, in our 2016 Form 10-K. This ASU did not materially affect our financial statements and disclosures, but did change certain presentation and disclosure of the fair value of certain plan assets in our pension and other postretirement benefit plan disclosures in our 2016 Form 10-K, for all periods presented.

Simplifying the Presentation of Debt Issuance Costs, ASU 2015-03

In April 2015, the FASB issued ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs. Debt issuance costs related to a recognized debt liability will be presented on the balance sheet as a direct deduction from the debt liability, similar to the presentation of debt discounts, rather than as an asset. Amortization of these costs will continue to be reported as interest expense. ASU 2015-03 is effective for annual and interim reporting periods beginning after December 15, 2015. We adopted ASU 2015-03 in the first quarter of 2016 on a retrospective basis. As of December 31, 2016, we presented the debt issuance costs, previously reported in other assets, as direct deductions from the carrying amount of long-term debt. The implementation of this standard resulted in reductions of other assets, non-current and long-term debt of $13 million in the Consolidated Balance Sheets as of December 31, 2015.

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. The new disclosure requirements will provide information about the nature, amount, timing and uncertainty of revenue and cash flows from revenue contracts with customers. The guidance is effective for annual and interim reporting periods beginning after December 15, 2017 with early adoption on January 1, 2017 permitted. Entities will have the option of using either a full retrospective or modified retrospective approach to adopting this guidance. Under the modified approach, an entity would recognize the cumulative effect of initially applying the guidance with an adjustment to the opening balance of retained earnings in the period of adoption.

We will adopt this standard for annual and interim reporting periods beginning after December 15, 2017 and are actively assessing all of our sources of revenue to determine the impact that adoption of the new standard will have on our financial position, results of operations and cash flows. Our evaluation includes identifying revenue streams by like contracts to allow for ease of implementation. A majority of our revenues are from regulated tariff offerings that provide natural gas or electricity with a defined contractual term. For such arrangements, we expect that the revenue from contracts with the customer will be equivalent to the electricity or gas delivered in that period. Therefore, we do not expect that there will be a significant shift in the timing or pattern of revenue recognition for regulated tariff based sales. The evaluation of other revenue streams is ongoing, including our non-regulated revenues and those tied to longer term contractual commitments. However, a number of industry-specific implementation issues are still unresolved and the final resolution of these issues could impact our current accounting policies and/or patterns for revenue recognition, as well as the transition method selected.

(2) ACQUISITION

Acquisition of SourceGas

On February 12, 2016, Black Hills Corporation acquired SourceGas, pursuant to the purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, including the assumption of $760 million in debt at closing. The purchase price was subject to post-closing adjustments for capital expenditures, indebtedness and working capital. Post-closing adjustments of approximately $11 million were agreed to and received from the sellers in June 2016. SourceGas is a 99.5% owned subsidiary of Black Hills Utility Holdings, Inc., a wholly-owned subsidiary of Black Hills Corporation and has been renamed Black Hills Gas Holdings, LLC. Black Hills Gas Holdings primarily operates four regulated natural gas utilities serving approximately 429,000 customers in Arkansas, Colorado, Nebraska and Wyoming, and a 512-mile regulated intrastate natural gas transmission pipeline in Colorado.

Cash consideration of $1.135 billion paid on February 12, 2016 to close the SourceGas Acquisition included net proceeds of approximately $536 million from the November 23, 2015 issuance of 6.325 million shares of our common stock, 5.98 million equity units, and $546 million in net proceeds from our debt offerings on January 13, 2016. We funded the cash consideration and out-of-pocket expenses payable with the SourceGas Acquisition using the proceeds listed above, cash on hand, and draws under our revolving credit facility.

In connection with the acquisition, the Company recorded pre-tax, incremental acquisition costs of approximately $45 million and $10 million for the years ending December 31, 2016 and 2015, respectively. These costs consisted of transaction costs, professional fees, employee-related expenses and other miscellaneous costs. The costs are recorded primarily in Other operating expenses and Interest expense on the Consolidated Statements of Income (Loss).

Our consolidated operating results for the year ended December 31, 2016 include revenues of $348 million and net income (loss) of $15 million, attributable to SourceGas for the period from February 12 through December 31, 2016. The SourceGas operating results are reported in our Gas Utilities segment. We believe the SourceGas Acquisition enhances Black Hills Corporation's utility growth strategy, providing greater operating scale, driving more efficient delivery of services and benefiting customers.

We accounted for the SourceGas Acquisition in accordance with ASC 805, Business Combinations, with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition date. Substantially all of SourceGas' operations are subject to the rate-setting authority of state regulatory commissions, and are accounted for in accordance with GAAP for regulated operations. SourceGas' assets and liabilities subject to rate setting provisions provide revenues derived from costs, including a return on investment of assets and liabilities included in rate base. As such, the fair value of these assets and liabilities equal their historical net book values.

The final purchase price allocation of the fair value of the assets acquired and liabilities assumed is included in the table below. The cash consideration paid of $1.124 billion, net of long-term debt assumed of $760 million and a working capital adjustment received of approximately $11 million, resulted in goodwill of $940 million. We had up to one year from the acquisition date to finalize the purchase price allocation. From the time of acquisition through December 31, 2016, we decreased goodwill by $6.7 million, reflecting the working capital adjustment received of $11 million and changes in valuation estimates for intangible assets, accrued liabilities and deferred taxes. Approximately $252 million of the goodwill balance is amortizable for tax purposes, relating to the partnership interests that were directly acquired in the transaction. The remainder of the goodwill balance is not amortizable for tax purposes. Goodwill generated from the acquisition reflects the benefits of increased operating scale and organic growth opportunities.

	(in thousands)
Purchase Price	$1,894,882
Less: Long-term debt assumed	(760,000)
Less: Working capital adjustment received	(10,644)
Consideration Paid, net of working capital adjustment received	$1,124,238
Allocation of Purchase Price:	
Current Assets	$112,983
Property, plant & equipment, net	1,058,093
Goodwill	939,695
Deferred charges and other assets, excluding goodwill	133,299
Current liabilities	(172,454)
Long-term debt	(758,874)
Deferred credits and other liabilities	(188,504)

Total consideration paid, net of working-capital adjustment received	$1,124,238

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Conditions of SourceGas Acquisition Regulatory Approval

The acquisition was subject to regulatory approvals from the public utility commissions in Arkansas (APSC), Colorado (CPUC), Nebraska (NPSC), and Wyoming (WPSC). Approvals were obtained from all commissions, subject to various conditions as set forth below:

The APSC order includes a twelve-month base rate moratorium, an annual $0.25 million customer credit for a term of up to five years or until we file the next rate review, whichever comes first, and provides the Company recovery of a portion of specific labor synergies at the time of the next base rate case, as well as various other terms and reporting requirements.

The CPUC order includes a two-year base rate moratorium for our regulated transmission and wholesale natural gas provider, a three-year base rate moratorium for our regulated gas distribution utility, an annual $0.2 million customer credit for a term of up to five-years or until we file the next rate review, whichever comes first, and provides the Company recovery of a portion of specific labor synergies at the time of the next base rate case, as well as various other terms and reporting requirements.

The NPSC order includes a three-year base rate moratorium, a three-year continuation of the Choice Gas Program, and provides the Company recovery of a portion of specific labor synergies at the time of the next base rate review, as well as various other terms and reporting requirements.

The WPSC order includes a three-year continuation of the Choice Gas Program, as well as various other terms and reporting requirements.

All four orders also disallowed recovery of goodwill and transaction costs. Recovery of transition costs is disallowed in Arkansas, Colorado and Nebraska. However, Wyoming allows for request of recovery of transition costs. Transition costs are those non-recurring costs related to the transition and integration of SourceGas. In the conditions mentioned above, the orders that include base rate moratoriums over a specified period of time do not impact our ability to adjust rates through riders or gas supply cost recovery mechanisms as allowed under the current enacted state tariffs. In certain cases, we may file for leave to increase general base rates and/or cost of sales recovery limited to material adverse changes, but only if there are changes in law or regulations or the occurrence of other extraordinary events outside of our control which result in a material adverse change in revenues, revenue requirement and/or increase in operating costs.

Settlement of Gas Supply Contract

On April 29, 2016, we settled for $40 million, a former SourceGas contract that required the Company to purchase all of the natural gas produced over the productive life of specific leaseholds in the Bowdoin Field in Montana. This contract’s intangible negative fair value is included with Current liabilities in the purchase price allocation. Approximately 75% of these purchases were committed to distribution customers in Nebraska, Colorado and Wyoming, which are subject to cost recovery mechanisms, while the remaining 25% was not subject to regulatory recovery. The prices to be paid under this contract varied, ranging from $6 to $8 per MMBtu at the time of acquisition and exceeded market prices. We applied for and were granted approval to terminate this agreement from the NPSC, CPUC and WPSC, on the basis that the agreement was not beneficial to customers in the long term. We received written orders allowing recovery of the net buyout costs associated with the contract termination that were allocated to regulated subsidiaries. These costs were recorded as a regulatory asset of approximately $30 million that is being recovered over a five-year period.

Pro Forma Results (unaudited)

We calculated the pro forma impact of the SourceGas Acquisition and the associated debt and equity financings on our operating results for the year ended December 31, 2016. The following pro forma results give effect to the acquisition, assuming the transaction closed on January 1, 2015:

	Pro Forma Results December 31,	
	2016	2015
	(in thousands, except per share amounts)	
Revenue	$1,651,936	$1,763,901
Net income (loss) available for common stock	$112,878	$(13,369)
Earnings (loss) per share, Basic	$2.17	$(0.26)
Earnings (loss) per share, Diluted	$2.12	$(0.26)

We derived the pro forma results for the SourceGas Acquisition based on historical financial information obtained from the sellers and certain management assumptions. Our pro forma adjustments relate to incremental interest expense associated with the financings to effect the transaction, and for the year ended December 31, 2015, also include adjustments to shares outstanding to reflect the equity issuances as if they had occurred on January 1, 2015, and to reflect pro forma dilutive effects of the equity units issued. The pro forma results do not reflect any cost savings, (or associated costs to achieve such savings) from operating efficiencies or restructuring that could result from the acquisition, and exclude any unique one-time items resulting from the acquisition that are not expected to have a continuing impact on the combined consolidated results. Pro forma results for the year ended December 31, 2016 reflect unfavorable weather impacts resulting in lower gas usage by our customers than in the same periods of the prior year. In addition, we calculated the tax impact of these adjustments at an estimated combined federal and state income tax rate of 37%.

These pro forma results are for illustrative purposes only and do not purport to be indicative of the results that would have been obtained had the SourceGas Acquisition been completed on January 1, 2015, or that may be obtained in the future.

Seller’s noncontrolling interest

One of the sellers retained 0.5% of the outstanding equity interests of SourceGas under the terms of the purchase agreement. As part of the transaction, we entered into an associated option agreement with that holder of the retained interest. The terms of this agreement provide us a call option to purchase the remaining interest beginning 366 days after the initial close of the SourceGas Transaction. If we choose not to exercise this option during a ninety-day period, the seller may exercise the put option to sell us the retained interest. The value of this 0.5% equity interest is shown as Redeemable noncontrolling interest on the accompanying consolidated balance sheets.

(3) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment at December 31 consisted of the following (dollars in thousands):

	2016		2015		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	$ 1,303,101	41	$ 1,136,847	43	30	63
Electric transmission	354,801	52	280,257	50	40	70
Electric distribution	712,575	48	699,775	47	15	75
Plant acquisition adjustment [(a)]	4,870	32	4,870	32	32	32
General	164,761	25	159,496	24	3	65
Capital lease - plant in service [(b)]	261,441	20	261,441	20	20	20
Total electric plant in service	2,801,549		2,542,686			
Construction work in progress	74,045		96,501			
Total electric plant	2,875,594		2,639,187			
Less accumulated depreciation and amortization	578,162		526,954			
Electric plant net of accumulated depreciation and amortization [(c)]	$ 2,297,432		$ 2,112,233			

(a) The plant acquisition adjustment is included in rate base and is being recovered with 14 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.

(c) Effective January 1, 2016, Cheyenne Light's natural gas utility results are reported in our Gas Utilities segment. Cheyenne Light's gas utility net Property, Plant and Equipment of $117 million previously reported in the Electric Utilities segment in 2015 is now presented in the Gas Utilities segment.

Gas Utilities	2016 Property, Plant and Equipment	Weighted Average Useful Life (in years)	2015 Property, Plant and Equipment	Weighted Average Useful Life (in years)	Lives (in years) Minimum	Maximum
Gas plant:						
Production	$10,821	35	$13	30	17	71
Gas transmission	338,729	48	45,104	60	22	70
Gas distribution	1,303,366	42	692,800	45	33	47
Cushion gas - depreciable [(a)]	3,539	28	—	0	28	28
Cushion gas - not depreciated [(a)]	47,055	0	—	0	0	0
Storage	27,686	31	—	0	15	48
General	339,382	19	122,109	22	3	44
Total gas plant in service	2,070,578		860,026			
Construction work in progress	28,446		11,854			
Total gas plant	2,099,024		871,880			
Less accumulated depreciation and amortization	194,585		120,458			
Gas plant net of accumulated depreciation and amortization [(b)]	$1,904,439		$751,422			

(a) Cushion gas is the portion of natural gas necessary to force saleable gas from a storage field into the transmission system and for system balancing, representing a permanent investment necessary to use storage facilities and maintain reliability. Depreciation of cushion gas is determined by the respective regulatory jurisdiction in which the cushion gas resides.

(b) Effective January 1, 2016, Cheyenne Light's natural gas utility results are reported in our Gas Utilities segment. Cheyenne Light's gas utility net Property, Plant and Equipment of $117 million previously reported in the Electric Utilities segment in 2015 is now presented in the Gas Utilities segment.

2016	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	Lives (in years) Minimum	Maximum
Power Generation	$ 161,430	$ 1,298	$ 162,728	$ 55,157	$ 107,571	33	2	40
Mining	151,709	4,642	156,351	105,219	51,132	13	2	59
Oil and Gas [(a)]	1,101,106	—	1,101,106	1,016,226	84,880	25	2	25

(a) Net Property, Plant and Equipment includes full cost pool net assets of approximately $43 million.

2015						Lives (in years)		
	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	$ 156,721	$ 2,182	$ 158,903	$ 51,471	$ 107,432	33	2	40
Mining	154,630	3,649	158,279	97,663	60,616	13	2	59
Oil and Gas	1,132,776	—	1,132,776	925,908	206,868	24	3	25

2016						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	$ 5,446	$ 11,974	$ 17,420	$ (6,115)	$ 23,535	8	3	30

(a) Accumulated depreciation, depletion and amortization at Corporate reflects the elimination of the capital lease accumulated depreciation difference between Colorado Electric and Black Hills Colorado IPP.

2015						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	$ 376	$ 15,377	$ 15,753	$ (4,770)	$ 20,523	10	5	30

(a) Accumulated depreciation, depletion and amortization at Corporate reflects the elimination of the capital lease accumulated depreciation difference between Colorado Electric and Black Hills Colorado IPP.

(4) 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 (Loss). Each owner of the facility is responsible for financing its investment in the jointly-owned facilities.

- South Dakota Electric 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. South Dakota Electric 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 South Dakota Electric with coal for its share of the Wyodak Plant, our 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.

- South Dakota Electric 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, including 200 MW from West to East and 200 MW from East to West. South Dakota Electric is committed to pay its proportionate share of the additions and replacements and operating and maintenance expenses of the transmission tie.

- South Dakota Electric 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 Mining subsidiary supplies coal to Wygen III for the life of the plant.

- Colorado Electric owns 50% of the Busch Ranch Wind Farm 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 farm 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 (Loss). 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 Mining subsidiary during the life of the facility. We retain responsibility for plant operations.

At December 31, 2016, our interests in jointly-owned generating facilities and transmission systems were (in thousands):

	Plant in Service	Construction Work in Progress	Accumulated Depreciation
Wyodak Plant	$113,611	$ 256	$ 55,878
Transmission Tie	$19,978	$ 13	$ 5,793
Wygen I	$109,412	$ 957	$ 37,156
Wygen III	$138,261	$ 1,806	$ 17,635
Busch Ranch Wind Farm	$18,899	$ —	$ 3,102

(5) BUSINESS SEGMENTS INFORMATION

Our reportable segments are based on our method of internal reporting, which is generally segregated by differences in products, services and regulation. All of our operations and assets are located within the United States.

Segment information was as follows (in thousands):

Total Assets (net of inter-company eliminations) as of December 31,	2016	2015
Electric [(a) (d)]	$2,859,559	$2,704,330
Gas [(b) (d)]	3,307,967	999,778
Power Generation [(a)]	73,445	60,864
Mining	67,347	76,358
Oil and Gas	96,435	208,956
Corporate [(c)]	110,691	576,357
Total assets	$6,515,444	$4,626,643

(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.

(b) Includes the assets acquired in the SourceGas acquisition on February 12, 2016.

(c) Corporate assets at December 31, 2015 include proceeds received from the November 23, 2015 equity offerings. These proceeds were subsequently used on February 12, 2016 to partially fund the SourceGas Acquisition.

(d) Effective January 1, 2016, Cheyenne Light's natural gas utility results are reported in our Gas Utilities segment. Assets of $135 million, previously reported in the Electric Utilities segment in 2015 are now presented in the Gas Utilities segment.

Capital Expenditures and Asset Acquisitions [(a)] for the years ended December 31,	2016	2015
Capital Expenditures		
Electric Utilities [(b)]	$258,739	$171,897
Gas Utilities [(b)]	173,930	99,674
Power Generation	4,719	2,694
Mining	5,709	5,767
Oil and Gas	6,669	168,925
Corporate	17,353	9,864
Total Capital Expenditures	467,119	458,821
Asset Acquisitions		
Gas Utilities [(b) (c)]	1,124,238	21,970
Total Capital Expenditures and Asset Acquisitions	$1,591,357	$480,791

(a) Includes accruals for property, plant and equipment.

(b) Effective January 1, 2016, Cheyenne Light's natural gas utility results are reported in our Gas Utilities segment. Cheyenne Light's gas utility property additions of $30 million previously reported in the Electric Utilities segment in 2015 is now presented in the Gas Utilities segment.

(c) SourceGas was acquired on February 12, 2016. Net cash paid of $1.124 billion was net of long-term debt assumed and working capital adjustments received. See Note 2. The 2015 acquisitions represent two acquisitions made by Wyoming Gas.

Property, Plant and Equipment as of December 31,	2016	2015
Electric Utilities [a] [b]	$2,875,594	$2,639,187
Gas Utilities [b] [c]	2,099,024	871,880
Power Generation [a]	162,728	158,903
Mining	156,351	158,279
Oil and Gas	1,101,106	1,132,776
Corporate	17,420	15,753
Total property, plant and equipment	$6,412,223	$4,976,778

(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.

(b) Effective January 1, 2016, Cheyenne Light's natural gas utility results are reported in our Gas Utilities segment. Cheyenne Light's gas utility Property, Plant and Equipment of $130 million, previously reported in the Electric Utilities segment in 2015 is now presented in the Gas Utilities segment.

(c) Includes Property, Plant and Equipment acquired in the SourceGas acquisition on February 12, 2016.

	Consolidating Income Statement							
Year ended December 31, 2016	Electric Utilities	Gas Utilities	Power Generation	Mining	Oil and Gas	Corporate	Inter-company Eliminations	Total
Revenue	$664,330	$838,343	$ 7,176	$29,067	$34,058	$—	$ —	$1,572,974
Inter-company revenue	12,951	—	83,955	31,213	—	347,500	(475,619)	—
Total revenue	677,281	838,343	91,131	60,280	34,058	347,500	(475,619)	1,572,974
Fuel, purchased power and cost of natural gas sold	261,349	352,165	—	—	—	456	(114,838)	499,132
Operations and maintenance	158,134	245,826	32,636	39,576	32,158	373,773	(326,847)	555,256
Depreciation, depletion and amortization	84,645	78,335	4,104	9,346	13,902	22,538	(23,827)	189,043
Impairment of long-lived assets[a]	—	—	—	—	106,957	—	—	106,957
Operating income (loss)	173,153	162,017	54,391	11,358	(118,959)	(49,267)	(10,107)	222,586
Interest expense	(56,237)	(76,586)	(3,758)	(401)	(4,864)	(109,035)	115,469	(135,412)
Interest income	5,946	1,573	1,983	24	—	97,147	(105,244)	1,429
Other income (expense), net	3,193	184	2	2,209	110	179,839	(181,034)	4,503
Income tax benefit (expense)	(40,228)	(27,462)	(17,129)	(3,137)	52,659	24,365	457	(10,475)
Net income (loss)	85,827	59,726	35,489	10,053	(71,054)	143,049	(180,459)	82,631
Net income attributable to noncontrolling interest	—	(102)	(9,559)	—	—	—	—	(9,661)
Net income (loss) available for common stock	$85,827	$59,624	$ 25,930	$10,053	$(71,054)	$143,049	$ (180,459)	$72,970

(a) Oil and Gas includes oil and gas property impairments (see Note 13).

Year ended December 31, 2015	Consolidating Income Statement Electric Utilities	Gas Utilities	Power Generation	Mining	Oil and Gas	Corporate	Inter-company Eliminations	Total
Revenue	$668,226	$551,300	$7,483	$34,313	$43,283	$—	$—	$1,304,605
Inter-company revenue	11,617	—	83,307	30,753	—	227,708	(353,385)	—
Total revenue	679,843	551,300	90,790	65,066	43,283	227,708	(353,385)	1,304,605
Fuel, purchased power and cost of natural gas sold	269,409	299,645	—	—	—	122	(112,289)	456,887
Operations and maintenance	160,924	140,723	32,140	41,630	41,593	225,721	(229,786)	412,945
Depreciation, depletion and amortization	80,929	32,326	4,329	9,806	29,287	9,273	(10,580)	155,370
Impairment of long-lived assets[(a)]	—	—	—	—	249,608	—	—	249,608
Operating income (loss)	168,581	78,606	54,321	13,630	(277,205)	(7,408)	(730)	29,795
Interest expense	(55,159)	(17,912)	(4,218)	(433)	(2,726)	(57,839)	54,568	(83,719)
Interest income	4,114	601	1,015	34	217	48,582	(52,942)	1,621
Other income (expense), net	1,216	315	71	2,247	(337)	70,889	(71,964)	2,437
Impairment of equity investments [(a)]	—	—	—	—	(4,405)	—	—	(4,405)
Income tax benefit (expense)	(41,173)	(22,304)	(18,539)	(3,608)	104,498	2,926	360	22,160
Net income (loss)	77,579	39,306	32,650	11,870	(179,958)	57,150	(70,708)	(32,111)
Net income attributable to noncontrolling interest	—	—	—	—	—	—	—	—
Net income (loss) available for common stock	$77,579	$39,306	$32,650	$11,870	$(179,958)	$57,150	$(70,708)	$(32,111)

(a) Oil and Gas includes ceiling test and equity investment impairments (see Note 13).

Year ended December 31, 2014	Consolidating Income Statement Electric Utilities	Gas Utilities	Power Generation	Mining	Oil and Gas	Corporate	Inter-company Eliminations	Total
Revenue	$643,446	$657,523	$6,401	$31,086	$55,114	$—	$—	$1,393,570
Inter-company revenue	14,110	—	81,157	32,272	—	222,460	(349,999)	—
Total revenue	657,556	657,523	87,558	63,358	55,114	222,460	(349,999)	1,393,570
Fuel, purchased power and cost of natural gas sold	291,644	403,781	—	—	—	116	(113,759)	581,782
Operations and maintenance	156,252	142,024	33,126	41,172	42,659	213,415	(225,473)	403,175
Depreciation, depletion and amortization	77,011	28,912	4,540	10,276	24,246	7,690	(7,930)	144,745
Operating income (loss)	132,649	82,806	49,892	11,910	(11,791)	1,239	(2,837)	263,868

Interest expense	(51,640)	(17,487)	(4,351)	(493)	(2,603)	(50,299)	55,913	(70,960)
Interest income	4,590	466	682	59	918	48,969	(53,759)	1,925
Other income (expense), net	1,074	124	(6)	2,275	183	61,605	(62,574)	2,681
Income tax benefit (expense)	(29,403)	(21,758)	(17,701)	(3,299)	4,768	24	744	(66,625)
Net income (loss)	57,270	44,151	28,516	10,452	(8,525)	61,538	(62,513)	130,889
Net income attributable to noncontrolling interest	—	—	—	—	—	—	—	—
Net income (loss) available for common stock	$57,270	$44,151	$ 28,516	$10,452	$(8,525)	$61,538	$ (62,513)	$130,889

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(6) LONG-TERM DEBT

Long-term debt outstanding was as follows (dollars in thousands):

	Due Date	Interest Rate at December 31, 2016	December 31, 2016	December 31, 2015
Corporate				
Senior unsecured notes due 2023	November 30, 2023	4.25%	$525,000	$525,000
Senior unsecured notes due 2020	July 15, 2020	5.88%	200,000	200,000
Corporate term loan due 2017 [(a)]			—	300,000
Remarketable junior subordinated notes [(b)]	November 1, 2028	3.50%	299,000	299,000
Senior unsecured notes due 2019	January 11, 2019	2.50%	250,000	—
Senior unsecured notes due 2026	January 15, 2026	3.95%	300,000	—
Senior unsecured notes due 2027	January 15, 2027	3.15%	400,000	—
Senior unsecured notes, due 2046	September 15, 2046	4.20%	300,000	—
Corporate term loan due 2019 [(a)]	August 9, 2019	1.74%	400,000	—
Corporate term loan due 2021	June 7, 2021	2.32%	24,406	—
Total Corporate Debt			2,698,406	1,324,000
Less unamortized debt discount			(4,413)	(1,890)
Total Corporate Debt, Net			2,693,993	1,322,110
Electric Utilities				
First Mortgage Bonds due 2044	October 20, 2044	4.43%	85,000	85,000
First Mortgage Bonds due 2044	October 20, 2044	4.53%	75,000	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
First Mortgage Bonds due 2037	November 20, 2037	6.67%	110,000	110,000
Industrial development revenue bonds due 2021 [(c)]	September 1, 2021	0.72%	7,000	7,000
Industrial development revenue bonds due 2027 [(c)]	March 1, 2027	0.72%	10,000	10,000
Series 94A Debt, variable rate [(c)]	June 1, 2024	0.88%	2,855	2,855
Total Electric Utilities Debt			544,855	544,855
Less unamortized debt discount			(94)	(99)
Total Electric Utilities Debt			544,761	544,756
Total long-term debt			3,238,754	1,866,866
Less current maturities			5,743	—
Less deferred financing costs [(d)]			21,822	13,184
Long-term debt, net of current maturities and deferred financing costs			$3,211,189	$1,853,682

(a) Variable interest rate, based on LIBOR plus a spread.
(b) See Note 12 for RSN details.
(c) Variable interest rate.
(d) Includes deferred financing costs associated with our Revolving Credit Facility of $2.3 million and $1.7 million as of December 31, 2016 and December 31, 2015, respectively.

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Scheduled maturities of long-term debt, excluding amortization of premiums or discounts, for future years are (in thousands):

2017	$5,743
2018	$5,743
2019	$655,742
2020	$205,742
2021	$8,436
Thereafter	$2,361,855

Our debt securities contain certain restrictive financial covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2016.

Substantially all of the tangible utility property of South Dakota Electric and Wyoming Electric is subject to the lien of indentures securing their first mortgage bonds. First mortgage bonds of South Dakota Electric and Wyoming Electric may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures. The first mortgage bonds issued by South Dakota Electric and Wyoming Electric are callable, but are subject to make-whole provisions which would eliminate any economic benefit for us to call the bonds.

Assumption of Long-Term Debt

At the closing of the SourceGas Acquisition on February 12, 2016, we assumed $760 million in long-term debt, consisting of the following:

- $325 million, 5.9% senior unsecured notes with an original issue date of April 16, 2007, due April 1, 2017.

- $95 million, 3.98% senior secured notes with an original issue date of September 29, 2014, due September 29, 2019.

- $340 million unsecured corporate term loan due June 30, 2017. Interest under this term loan was LIBOR plus a margin of 0.875%.

The $760 million in long-term debt assumed in the SourceGas Acquisition was repaid in August 2016.

Debt Transactions

On August 19, 2016, we completed a public debt offering of $700 million principal amount of senior unsecured notes. The debt offering consisted of $400 million of 3.15% 10-year senior notes due January 15, 2027 and $300 million of 4.20% 30-year senior notes due September 15, 2046 (together the “Notes”). The proceeds of the Notes were used for the following:

- Repay the $325 million 5.9% senior unsecured notes assumed in the SourceGas Acquisition;

- Repay the $95 million, 3.98% senior secured notes assumed in the SourceGas Acquisition;

- Repay the remaining $100 million on the $340 million unsecured term loan assumed in the SourceGas Acquisition;

- Pay down $100 million of the $500 million three-year unsecured term loan discussed below;

- Payment of $29 million for the settlement of $400 million notional interest rate swap; and

- Remainder was used for general corporate purposes.

On August 9, 2016, we entered into a $500 million, three-year, unsecured term loan expiring on August 9, 2019. The proceeds of this term loan were used to pay down $240 million of the $340 million unsecured term loan assumed in the SourceGas Acquisition and the $260 million term loan expiring on April 12, 2017. This new term loan has substantially similar terms and covenants as the amended and restated Revolving Credit Facility.

In accordance with regulatory orders related to the early termination and settlement of the gas supply contract described in Note 1, on June 7, 2016, we entered into a 2.32%, $29 million term loan, due June 7, 2021. Proceeds from this term loan were used to finance the early termination of the gas supply contract, resulting in a regulatory asset. Principal and interest are payable quarterly at approximately $1.6 million, the first of which was paid on June 30, 2016.

On January 13, 2016, we completed a public debt offering of $550 million principal amount of senior unsecured notes. The debt offering consisted of $300 million of 3.95%, ten-year senior notes due 2026, and $250 million of 2.50%, three-year senior notes due 2019. After discounts and underwriter fees, net proceeds from the offering totaled $546 million and were used as funding for the SourceGas Acquisition. The discounts are amortized over the life of each respective note.

Amortization Expense

Our deferred financing costs and associated amortization expense included in Interest expense on the accompanying Consolidated Statements of Income (Loss) were as follows (in thousands):

	Deferred Financing Costs Remaining at December 31, 2016	Amortization Expense for the years ended December 31,		
		2016	2015	2014
Revolving Credit Facility	$ 2,341	$537	$504	$616
Senior unsecured notes due 2023	2,921	494	494	653
Senior unsecured notes due 2019	763	643	—	—
Senior unsecured notes due 2020	592	167	167	167
Senior unsecured notes due 2026	2,318	262	—	—
Senior unsecured notes due 2027	3,281	121	—	—
Senior unsecured notes due 2046	3,193	37	—	—
Corporate term loan due 2019	287	144	—	—
Bridge Term Loan	—	843	4,213	—
RSNs due 2028	1,449	122	10	—
First mortgage bonds due 2044 (South Dakota Electric)	663	24	24	6
First mortgage bonds due 2044 (Wyoming Electric)	613	23	22	6
First mortgage bonds due 2032	518	33	33	33
First mortgage bonds due 2039	1,734	76	76	76
First mortgage bonds due 2037	643	31	31	31
Other	506	304	43	53
Total	$ 21,822	$3,861	$5,617	$1,641

Dividend Restrictions

Our credit facility and other debt obligations contain restrictions on the payment of cash dividends when a default or event of default occurs. In addition, the agreements governing our equity units contain restrictions on the payment of cash dividends upon any time we have exercised our right to defer payment of contract adjustment payments under the purchase contracts or interest payments under the RSNs included in such equity units. As of December 31, 2016, 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, 2016:

- 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, 2016, the restricted net assets at our Electric and Gas Utilities were approximately $257 million.

(7) NOTES PAYABLE

Our Revolving Credit Facility and debt securities contain certain restrictive financial covenants. As of December 31, 2016, 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, 2016	December 31, 2015
Revolving Credit Facility	$96,600	$ 76,800

Revolving Credit Facility

On August 9, 2016, we amended and restated our corporate Revolving Credit Facility to increase total commitments to $750 million from $500 million and extend the term through August 9, 2021 with two one-year extension options (subject to consent from the lenders). This facility is similar to the former agreement, which includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents and subject to receipt of additional commitments from existing or new lenders, to increase total commitments of the facility up to $1.0 billion. 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 either S&P or Moody's for our unsecured debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings, and letters of credit were 0.250%, 1.250%, and 1.250%, respectively, at December 31, 2016. A 0.200% commitment fee is charged on the unused amount of the Revolving Credit Facility.

On December 22, 2016, we implemented a $750 million, unsecured CP Program that is backstopped by the Revolving Credit Facility. Amounts outstanding under the Revolving Credit Facility and the CP Program, either individually or in the aggregate, cannot exceed $750 million. The notes issued under the CP Program may have maturities not to exceed 397 days from the date of issuance and bear interest (or are sold at par less a discount representing an interest factor) based on, among other things, the size and maturity date of the note, the frequency of the issuance and our credit ratings. Under the CP Program, any borrowings rank equally with our unsecured debt. Notes under the CP Program are not registered and are offered and issued pursuant to a registration exemption. We did not borrow under the CP Program in 2016 and do not have any notes outstanding as of December 31, 2016.

As of December 31, 2016 and 2015, we had outstanding letters of credit totaling approximately $36 million and approximately $33 million, respectively.

Deferred financing costs on the facility of $5.4 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 (Loss). The deferred financing costs on the new facility are being amortized as follows (in thousands):

	Deferred Financing Costs Remaining on Balance Sheet as of	Amortization Expense for the years ended December 31,		
		2016	2015	2014

	December 31, 2016			
Revolving Credit Facility	$ 2,341	$537	$504	$616

Debt Covenants

On December 7, 2016, we amended our Revolving Credit Facility and term loan agreements, allowing the exclusion of the Remarketable Junior Subordinated Notes (RSNs) from our Consolidated Indebtedness to Capitalization Ratio covenant calculation. Under the amended and restated Revolving Credit Facility and term loan agreements, we are required to maintain a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.70 to 1.00 for the quarter ending December 31, 2016 and subsequently for future quarters beginning March 31, 2017, maintain the ratio not to exceed 0.65 to 1.00. Our Consolidated Indebtedness to Capitalization Ratio is calculated by dividing (i) Consolidated Indebtedness, which includes letters of credit, certain guarantees issued and excludes RSNs by (ii) Capital, which includes Consolidated Indebtedness plus Net Worth, which excludes noncontrolling interests in subsidiaries and includes the aggregate outstanding amount of the RSNs.

Our Revolving Credit Facility and our Term Loans require compliance with the following financial covenant at the end of each quarter:

	At December 31, 2016	Covenant Requirement at December 31, 2016
Consolidated Indebtedness to Capitalization Ratio	62 %	Less than 70%

(8) 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 Mining segment and removal of fuel tanks, asbestos, transformers containing polychlorinated biphenyls, an evaporation pond and wind turbines at the regulated Electric Utilities segment, retirement of gas pipelines at our Gas Utilities 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, 2015	Liabilities Incurred	Liabilities Settled	Accretion	Liabilities Acquired (a)	Revisions to Prior Estimates (b)(c)	December 31, 2016
Electric Utilities	$ 4,462	$ —	$ —	$ 191	$ —	$ 8	$ 4,661
Gas Utilities	136	—	—	791	22,412	6,436	29,775
Mining	18,633	—	(105)	822	—	(6,910)	12,440
Oil and Gas	21,504	3	(2,049)	1,382	—	1,923	22,763
Total	$ 44,735	$ 3	$ (2,154)	$ 3,186	$ 22,412	$ 1,457	$ 69,639

	December 31, 2014	Liabilities Incurred	Liabilities Settled	Accretion	Liabilities Acquired	Revisions to Prior Estimates (c)	December 31, 2015
Electric Utilities	$ 7,012	$ —	$ (2,733)	$ 183	$ —	$ —	$ 4,462
Gas Utilities	291	—	(168)	13	—	—	136
Mining	19,138	—	—	993	—	(1,498)	18,633
Oil and Gas	20,945	828	(1,792)	1,371	—	152	21,504
Total	$ 47,386	$ 828	$ (4,693)	$ 2,560	$ —	$ (1,346)	$ 44,735

(a) Represents our legal liability for retirement of gas pipelines, specifically to purge and cap these lines in accordance with Federal regulations. Approximately $22 million was recorded with the purchase price allocation of SourceGas.

(b) The Gas Utilities Revision to Prior Estimates represents our legal liability for retirement of gas pipelines, specifically to purge and cap these lines in accordance with Federal regulations.

(c) The 2016 Mining Revision to Prior Estimates reflects an approximately 33% reduction in equipment costs as promulgated by the State of Wyoming. The 2015 Mining Revision to Prior Estimates reflects a change in backfill yards and disturbed acreage used in calculating the estimated liability as well as changes in inflation rate assumptions.

We also have legally required AROs related to certain assets within our electric 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.

(9) 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 of crude oil and natural gas reserves and production, our retail natural gas marketing activities, and our fuel procurement for certain of our gas-fired generation assets; and

- Interest rate risk associated with our variable rate debt.

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, 2016, our credit exposure included a $1.1 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 (Loss) and Consolidated Statements of Comprehensive Income (Loss) are detailed below and within Note 10.

Oil and Gas

We produce natural gas, NGLs and crude oil through our exploration and production activities. Our natural long positions, or unhedged open positions from these activities, 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, swaps and options to hedge portions of our crude oil and natural gas production. Futures contracts provide the requirement to buy or sell the commodity at a fixed price in the future. Option contracts provide the right, but not the obligation to buy or sell the commodity at a fixed price. Swap contracts require receipt of payment based on the difference between the fixed price and the settled commodity market price on the settlement date. We elect hedge accounting on the swaps and futures contracts. These transactions were designated upon 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 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 and terms of our crude oil futures and options and natural gas futures held at our Oil and Gas segment are comprised of short positions. A short position is a contract to sell the commodity while a long position is a contract to purchase the commodity. We had the following short positions as of:

	December 31, 2016			December 31, 2015	
	Crude oil futures and swaps [(b)]	Crude oil options	Natural gas futures and swaps [(b)]	Crude oil futures and swaps [(b)]	Natural gas futures and swaps [(b)]
Notional [(a)]	108,000	36,000	2,700,000	198,000	4,392,500
Maximum terms in months [(c)]	24	12	24	24	24

(a) Crude in Bbls, gas in MMBtus.
(b) These financial instruments were designated as cash flow hedges upon inception.
(c) Refers to the maximum forward period hedged.

Based on December 31, 2016 market prices, a $0.9 million loss would be reclassified from AOCI during 2017. Estimated and actual realized gains or losses will change during future periods as market prices fluctuate.

Utilities

The operations of our utilities, including natural gas sold by our Gas Utilities and natural gas used by our Electric Utilities' generation plants or those plants under PPAs where our Electric 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, over-the-counter swaps 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.

For our regulated utilities' hedging plans, 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. When the related costs are recovered through our rates, the hedging activity is recognized in the Consolidated Statements of Income (Loss), or the Consolidated Statements of Comprehensive Income (Loss).

We buy, sell and deliver natural gas at competitive prices by managing commodity price risk. As a result of these activities, this area of our business is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks using over-the-counter and exchange traded options and swaps with counterparties in anticipation of forecasted purchases and/or sales during time frames ranging from January 2017 through April 2019. A portion of our over-the-counter swaps have been designated as cash flow hedges to mitigate the commodity price risk associated with deliveries under fixed price forward contracts to deliver gas to our Choice Gas Program customers. The effective portion of the gain or loss on these designated derivatives is reported in AOCI in the accompanying Consolidated Balance Sheets and the ineffective portion, if any is reported in Fuel, purchased power and cost of natural gas sold. Effectiveness of our hedging position is evaluated at least quarterly.

The contract or notional amounts and terms of the natural gas derivative commodity instruments held by our Utilities are comprised of both short and long positions. We had the following net long positions as of:

	December 31, 2016		December 31, 2015	
	Notional (MMBtus)	Maximum Term (months) [a]	Notional (MMBtus)	Maximum Term (months) [a]
Natural gas futures purchased	14,770,000	48	20,580,000	60
Natural gas options purchased, net [b]	3,020,000	5	2,620,000	3
Natural gas basis swaps purchased	12,250,000	48	18,150,000	60
Natural gas over-the-counter swaps, net [c]	4,622,302	28	—	0
Natural gas physical commitments, net [d]	21,504,378	10	—	0

(a) Term reflects the maximum forward period hedged.
(b) Volumes purchased as of December 31, 2016 is net of 2,133,000 MMBtus of collar options (call purchase and put sale) transactions.
(c) As of December 31, 2016, 2,138,300 MMBtus were designated as cash flow hedges for the natural gas over-the-counter swaps purchased.
(d) Volumes exclude contracts that qualify for normal purchase, normal sales exception.

Financing Activities

In October 2015 and January 2016, we entered into forward starting interest rate swaps with a notional value totaling $400 million to fix the Treasury yield component associated with the anticipated issuance of senior notes. These swaps were settled at a loss of $29 million in connection with the issuance of our $400 million of unsecured ten-year senior notes on August 10, 2016. The effective portion of the loss in the amount of $28 million was recognized as a component of AOCI and will be recognized as a component of interest expense over the ten-year life of the $400 million unsecured note issued on August 19, 2016. The ineffective portion of $1.0 million, related to the timing of the debt issuance, was recognized in earnings as a component of interest expense. 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, 2016	December 31, 2015	
	Interest Rate Swaps [a]	Interest Rate Swaps [a]	Interest Rate Swaps [b]
Notional	$50,000	$75,000	$250,000
Weighted average fixed interest rate	4.94 %	4.97 %	2.29 %
Maximum terms in months	1	13	16
Derivative assets, non-current	$—	$—	$3,441
Derivative liabilities, current	$90	$2,835	$—
Derivative liabilities, non-current	$—	$156	$—

(a) The $25 million in swaps expired in October 2016 and the $50 million in swaps expired in January 2017. These swaps were designated to borrowings on our Revolving Credit Facility and were priced using three-month LIBOR, matching the floating portion of the related borrowings.
(b) These swaps were settled on August 19, 2016.

Based on December 31, 2016 market interest rates and balances related to our designated interest rate swaps, a loss of approximately $2.9 million would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. This total includes the $28 million loss currently deferred in AOCI. 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) is presented below for the years ended December 31, 2016 and 2015 (in thousands). Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

	December 31, 2016			
Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	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	Interest expense	$ (3,899)	Interest expense	$ (953)
Commodity derivatives	Revenue	11,019		—
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(14)		—
Total impact from cash flow hedges		$ 7,106		$ (953)

	December 31, 2015			
Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	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	Interest expense	$ (3,647)		$ —
Commodity derivatives	Revenue	14,460		—
Total		$ 10,813		$ —

	December 31, 2014			
Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	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	Interest expense	$ (3,669)	$ —
Commodity derivatives	Revenue	(1,995)	—
Total		$ (5,664)	$ —

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The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss) for the years ended December 31, 2016, 2015 and 2014. The amounts included in the table below exclude gains and losses arising from ineffectiveness because these amounts are immediately recognized in the Consolidated Statements of Net Income (Loss) as incurred.

	December 31, 2016	December 31, 2015	December 31, 2014
	(In thousands)		
Increase (decrease) in fair value:			
Interest rate swaps	$(31,222)	$ 2,888	$ (536)
Forward commodity contracts	(573)	9,782	14,681
Recognition of (gains) losses in earnings due to settlements:			
Interest rate swaps	3,899	3,647	3,669
Forward commodity contracts	(11,005)	(14,460)	1,995
Total other comprehensive income (loss) from hedging	$(38,901)	$ 1,857	$ 19,809

Derivatives Not Designated as Hedge Instruments

The following table summarizes the impacts of derivative instruments not designated as hedge instruments on our Consolidated Statements of Income (Loss) for the years ended December 31, 2016, 2015 and 2014 (in thousands). Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	2016 Amount of Gain/(Loss) on Derivatives Recognized in Income	2015 Amount of Gain/(Loss) on Derivatives Recognized in Income	2014 Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Revenue	$ (50)	$ —	$ —
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	940	—	—
		$ 890	$ —	$ —

As discussed above, financial instruments used in our regulated utilities are not designated as cash flow hedges. However, there is no earnings impact because the unrealized gains and losses arising from the use of these financial instruments are recorded as Regulatory assets or Regulatory liabilities. The net unrealized losses included in our Regulatory assets or Regulatory liability accounts related to the hedges in our Utilities were $8.8 million and $24 million at December 31, 2016 and 2015, respectively.

(10) FAIR VALUE MEASUREMENTS

Recurring Fair Value Measurements

There have been no significant transfers between Level 1 and Level 2 derivative balances during 2016 or 2015. 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 11. 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, 2016				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
Assets:					
Commodity derivatives - Oil and Gas	$ —	$ 2,886	$ —	$ (2,733)	$ 153
Commodity derivatives - Utilities	—	7,469	—	(3,262)	4,207
Interest rate swaps	—	—	—	—	—
Total	$ —	$ 10,355	$ —	$ (5,995)	$ 4,360
Liabilities:					
Commodity derivatives - Oil and Gas	$ —	$ 1,586	$ —	$ —	$ 1,586
Commodity derivatives - Utilities	—	12,201	—	(11,144)	1,057
Interest rate swaps	—	90	—	—	90
Total	$ —	$ 13,877	$ —	$ (11,144)	$ 2,733

	As of December 31, 2015				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
Assets:					
Commodity derivatives - Oil and Gas	$ —	$ 10,644	$ —	$ (10,644)	$ —
Commodity derivatives - Utilities	—	2,293	—	(2,293)	—
Interest rate swaps	—	3,441	—	—	3,441
Total	$ —	$ 16,378	$ —	$ (12,937)	$ 3,441
Liabilities:					
Commodity derivatives - Oil and Gas	$ —	$ 556	$ —	$ (556)	$ —
Commodity derivatives - Utilities	—	24,585	—	(24,585)	—
Interest rate swaps	—	2,991	—	—	2,991

Total	$ —	$ 28,132	$ —	$ (25,141)	$ 2,991

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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.

The following tables present the fair value and balance sheet classification of our derivative instruments as of December 31, (in thousands):

		2016		2015	
	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	$1,161	$ —	$9,981	$ —
Commodity derivatives	Derivative assets - non-current	124	—	663	—
Interest rate swaps	Derivative assets - non-current	—	—	3,441	—
Commodity derivatives	Derivative liabilities - current	—	1,090	—	465
Commodity derivatives	Derivative liabilities - non-current	—	238	—	91
Interest rate swaps	Derivative liabilities - current	—	90	—	2,835
Interest rate swaps	Derivative liabilities - non-current	—	—	—	156
Total derivatives designated as hedges		$1,285	$ 1,418	$14,085	$ 3,547
Derivatives not designated as hedges:					
Commodity derivatives	Derivative assets - current	$2,977	$ —	$—	$ —
Commodity derivatives	Derivative assets - non-current	98	—	—	—
Commodity derivatives	Derivative liabilities - current	—	1,279	—	9,586
Commodity derivatives	Derivative liabilities - non-current	—	36	—	12,706
Interest rate swaps	Derivative liabilities - current	—	—	—	—
Interest rate swaps	Derivative liabilities - non-current	—	—	—	—
Total derivatives not designated as hedges		$3,075	$ 1,315	$—	$ 22,292

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, 2016 and December 31, 2015, 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, 2016 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	$ 2,886	$ (2,733)	$ 153
Utilities	4,269	(3,262)	1,007
Interest Rate Swaps	—	—	—
Total derivative assets subject to a master netting agreement or similar arrangement	7,155	(5,995)	1,160
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas	—	—	—
Utilities	3,200	—	3,200
Interest rate swaps	—	—	—
Total derivative assets not subject to a master netting agreement or similar arrangement	3,200	—	3,200
Total derivative assets	$ 10,355	$ (5,995)	$ 4,360

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	$ 1,586	$ —	$ 1,586
Utilities	11,144	(11,144)	—
Interest Rate Swaps	—	—	—
Total derivative liabilities subject to a master netting agreement or similar arrangement	12,730	(11,144)	1,586
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas	—	—	—
Utilities	1,057	—	1,057
Interest Rate Swaps	90	—	90
Total derivative liabilities not subject to a master netting agreement or similar arrangement	1,147	—	1,147
Total derivative liabilities	$ 13,877	$ (11,144)	$ 2,733

Offsetting of derivative assets and derivative liabilities on our Consolidated Balance Sheets as of December 31, 2015 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	$ 10,644	$ (10,644)	$ —
Utilities	2,293	(2,293)	—
Interest rate swaps	3,441	—	3,441
Total derivative assets subject to a master netting agreement or similar arrangement	16,378	(12,937)	3,441
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas	—	—	—
Utilities	—	—	—
Interest rate swaps	—	—	—
	—	—	—

Total derivative assets not subject to a master netting agreement or similar arrangement			
Total derivative assets	$ 16,378	$ (12,937)	$ 3,441

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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	$ 556	$ (556)	$ —
Utilities	24,585	(24,585)	—
Interest Rate Swaps	2,991	—	2,991
Total derivative liabilities subject to a master netting agreement or similar arrangement	28,132	(25,141)	2,991
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas	—	—	—
Utilities	—	—	—
Interest Rate Swaps	—	—	—
Total derivative liabilities not subject to a master netting agreement or similar arrangement	—	—	—
Total derivative liabilities	$ 28,132	$ (25,141)	$ 2,991

(11) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 10, were as follows at December 31 (in thousands):

	2016 Carrying Amount	Fair Value	2015 Carrying Amount	Fair Value
Cash and cash equivalents [(a)]	$13,580	$13,580	$440,861	$440,861
Restricted cash and equivalents [(a)]	$2,274	$2,274	$1,697	$1,697
Notes payable [(b)]	$96,600	$96,600	$76,800	$76,800
Long-term debt, including current maturities [(c)]	$3,216,932	$3,351,305	$1,853,682	$1,992,274

(a) Carrying value approximates fair value. Cash and restricted cash are classified in Level 1 in the fair value hierarchy.

(b) Notes payable consist of borrowings on our Revolving Credit Facility. Carrying value approximates fair value due to the short-term length of maturity; since these borrowings are not traded on an exchange, they are classified in Level 2 in the fair value hierarchy.

(c) 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 6 and Note 7.

(12) EQUITY

Equity Units

On November 23, 2015, we issued 5.98 million equity units for total gross proceeds of $299 million. Each Equity Unit has a stated amount of $50 and consists of (i) a forward purchase contract to purchase the Company's common stock and (ii) a 1/20, or 5%, undivided beneficial ownership interest in $1,000 principal amount of RSNs due 2028. The RSNs, a debt instrument, and the forward purchase contracts, an equity instrument, are deemed to be separate instruments as the investor may trade the RSNs separately from the forward purchase contract and may also settle the forward purchase contract separately.

The forward purchase contracts obligate the holders to purchase from the Company on the settlement date, which shall be no later than November 1, 2018, for a price of $50 in cash, the following number of shares of our common stock, subject to anti-dilution adjustments:

- if the "Applicable Market Value" (AMV) of the Company's common stock, which is the average volume-weighted average price of the Company's common stock for the trading days during the 20 consecutive scheduled trading day period ending on the third scheduled trading day immediately preceding the forward purchase contract settlement date, equals or exceeds $47.2938, 1.0572 shares of the Company's common stock per Equity Unit;

- if the AMV is less than $47.2938 but greater than $40.25, a number of shares of the Company's common stock having a value, based on the AMV, equal to $50; and

- if the AMV is less than or equal to $40.25, 1.2422 shares of the Company's common stock.

The RSNs bear interest at a rate of 3.5% per year, payable quarterly, and mature on November 1, 2028. The RSNs will be remarketed in 2018. If this remarketing is successful, the interest rate on the RSNs will be reset, and thereafter interest will be payable semi-annually at the reset rate. If there is no successful remarketing, the interest rate on the RSNs will not be reset, and the holders of the RSNs will have the right to put the RSNs to the Company at a price equal to 100% of the principal amount, and the proceeds of the put right will be deemed to have been applied against the holders' obligation under the forward purchase contracts.

The Company will also pay the Equity Unit holders quarterly contract adjustment payments at a rate of 4.25% per year of the stated amount of $50 per Equity Unit, or $2.125 per year up to November 1, 2018. The present value of the future contract adjustment payments, $33 million, is recorded as a reduction of shareholders' equity. Until settlement of the forward purchase contracts, the shares of stock underlying each forward purchase contract are not outstanding. The forward purchase contracts will only be included in the computation of diluted earnings per share to the extent they are dilutive. As of December 31, 2016, the forward purchase contracts were dilutive and therefore included in the computation of diluted earnings per share. Basic earnings per share will not be affected until the forward purchase contracts are settled and the holders thereof become stockholders.

Selected information about our equity units is presented below (in thousands except for percentages):

Issuance Date	Units Issued	Total Net Proceeds	Total Long-term Debt (RSNs)	RSN Interest Rate (annual)	Stock Purchase Contract Rate (annual)	Stock Purchase Contract Liability as of December 31, 2016

11/23/2015	5,980	$290,030	$299,000	3.50	%	4.25	%	$23,335

At-the-Market Equity Offering Program

On March 18, 2016, we implemented an ATM equity offering program allowing us to sell shares of our common stock with an aggregate value of up to $200 million. The shares may be offered from time to time pursuant to a sales agreement dated March 18, 2016. Shares of common stock are offered pursuant to our shelf registration statement filed with the SEC. During the three months ended December 31, 2016, we issued 218,647 common shares for $13 million, net of $0.1 million in commissions under the ATM equity offering program. Through December 31, 2016, we have sold and issued an aggregate of 1,968,738 shares of common stock under the ATM equity offering program for $119 million, net of $1.2 million in commissions. As of December 31, 2016, there were no shares sold that were not settled.

Common Stock Offering

On November 23, 2015, we issued 6.325 million shares of Common stock pursuant to a public offering at $40.25 per share. Net proceeds were $246 million. The proceeds from the offering were used to partially fund the purchase of SourceGas, which closed on February 12, 2016.

Equity Compensation Plans

Our 2015 Omnibus Incentive Plan allows for the granting of stock, restricted stock, restricted stock units, stock options and performance shares. We had 1,115,557 shares available to grant at December 31, 2016.

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, 2016, total unrecognized compensation expense related to non-vested stock awards was approximately $13.5 million and is expected to be recognized over a weighted-average period of 2.0 years.
Stock-based compensation expense included in Operations and maintenance on the accompanying Consolidated Statements of Income (Loss) was as follows for the years ended December 31 (in thousands):

	2016	2015	2014
Stock-based compensation expense	$10,885	$4,076	$9,329

Stock Options

The Company has not issued any stock options since 2014 and has 119,415 stock options outstanding at December 31, 2016. The amount of stock options granted during the last three years, related exercise activity and the number of stock options outstanding at December 31, 2016 are not material to the Company’s consolidated financial statements.

Restricted Stock

The fair value of restricted stock and restricted stock unit 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 and restricted stock units at December 31, 2016, was as follows:

	Restricted Stock	Weighted-Average Grant Date Fair Value
	(in thousands)	
Balance at beginning of period	202	$ 48.96
Granted	195	53.55
Vested	(88)	48.00
Forfeited	(14)	51.89
Balance at end of period	295	$ 52.15

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)
2016	$ 53.55	$ 4,602
2015	$ 50.01	$ 6,009
2014	$ 54.34	$ 6,114

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As of December 31, 2016, there was $10.3 million of unrecognized compensation expense related to non-vested restricted stock that is expected to be recognized over a weighted-average period of 2.1 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 $2.3 million at December 31, 2016 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, 2014	January 1, 2014 - December 31, 2016	44	0%	200%
January 1, 2015	January 1, 2015 - December 31, 2017	43	0%	200%
January 1, 2016	January 1, 2016 - December 31, 2018	53	0%	200%

A summary of the status of the Performance Share Plan at December 31 was as follows:

	Equity Portion		Liability Portion	
	Shares	Weighted-Average Grant Date Fair Value [(a)]	Shares	Weighted-Average Fair Value at December 31, 2016
	(in thousands)		(in thousands)	
Performance Shares balance at beginning of period	74	$ 47.21	74	
Granted	27	47.76	27	
Forfeited	—	—	—	
Vested	(30)	35.86	(30)	
Performance Shares balance at end of period	71	$ 52.29	71	$ 48.05

(a) The grant date fair values for the performance shares granted in 2016, 2015 and 2014 were determined by Monte Carlo simulation using a blended volatility of 24%, 21% and 23%, 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.

The weighted-average grant-date fair value of performance share awards granted was as follows in the years ended:

	Weighted Average Grant Date Fair Value

December 31, 2016 $ 47.76
December 31, 2015 $ 54.92
December 31, 2014 $ 55.18

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, 2013 to December 31, 2015	2016	—	$—	$ —
January 1, 2012 to December 31, 2014	2015	69	$3,657	$ 7,314
January 1, 2011 to December 31, 2013	2014	59	$3,011	$ 6,020

On January 24, 2017, the Compensation Committee of our Board of Directors determined that the Company's performance criteria for the January 1, 2014 through December 31, 2016 performance period was not met. As a result, there will be no payout for this period.

As of December 31, 2016, there was $3.1 million of unrecognized compensation expense related to outstanding performance share plans that is expected to be recognized over a weighted-average period of 1.8 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):

	2016	2015
Shares Issued	51	66
Weighted Average Price	$58.24	$44.79
Unissued Shares Available	356	408

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.

Sale of Noncontrolling Interest in Subsidiary

Black Hills Colorado IPP owns and operates a 200 MW, combined-cycle natural gas generating facility located in Pueblo, Colorado. On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for $216 million to a third-party buyer. FERC approval of the sale was received on March 29, 2016. Black Hills Electric Generation is the operator of the facility, which is contracted to provide capacity and energy through 2031 to Black Hills Colorado Electric. Proceeds from the sale were used to pay down short-term debt and for other general corporate purposes.

ASC 810 requires the accounting for a partial sale of a subsidiary in which control is maintained and the subsidiary continues to be consolidated. The partial sale is required to be recorded as an equity transaction with no resulting gain or loss on the sale. GAAP requires that noncontrolling interests in subsidiaries and affiliates be reported in the equity section of a company's balance sheet. Distributions of net income attributable to noncontrolling interests are due within 30 days following the end of a quarter, but may be withheld as necessary by Black Hills Electric Generation.

Net income available for common stock for the year ended December 31, 2016, was reduced by $9.6 million attributable to this noncontrolling interest. The net income allocable to the noncontrolling interest holders is based on ownership interests with the exception of certain agreed upon adjustments.

Black Hills Colorado IPP has been determined to be a variable interest entity (VIE) in which the Company has a variable interest. Black Hills Electric Generation has been determined to be the primary beneficiary of the VIE as Black Hills Electric Generation is the operator and manager of the generation facility and, as such, has the power to direct the activities that most significantly impact Black Hills Colorado IPP's economic performance. Black Hills Electric Generation, as the primary beneficiary, continues to consolidate Black Hills Colorado IPP. Black Hills Colorado IPP has not received financial or other support from the Company outside of pre-existing contractual arrangements during the reporting period. Black Hills Colorado IPP does not have any debt and its cash flows from operations are sufficient to support its ongoing operations.

We have recorded the following assets and liabilities on our consolidated balance sheets related to the VIE described above as of December 31:

	2016	2015
	(in thousands)	
Assets		
Current assets	$12,627	$ —
Property, plant and equipment of variable interest entities, net	$218,798	$ —
Liabilities		
Current liabilities	$4,342	$ —

(13) IMPAIRMENT OF ASSETS

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 throughout 2016, we have recorded non-cash ceiling test impairments of oil and gas assets included in the Oil and Gas segment totaling approximately $92 million for the year ended December 31, 2016. 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. For natural gas, the average NYMEX price was $2.48 per Mcf, adjusted to $2.25 per Mcf at the wellhead; for crude oil, the average NYMEX price was $42.75 per barrel, adjusted to $37.35 per barrel at the wellhead.

In 2015, we recorded a non-cash ceiling test impairment of oil and gas assets included in the Oil and Gas segment totaling approximately $250 million for the year ended December 31, 2015. 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. For natural gas, the average NYMEX price was $2.59 per Mcf, adjusted to $1.27 per Mcf at the wellhead; for crude oil, the average NYMEX price was $50.28 per barrel, adjusted to $44.72 per barrel at the wellhead.

During the second quarter of 2016, we advanced our Oil and Gas strategy, identifying certain non-core assets which may be sold as they are not expected to be utilized in the Cost of Service Gas Program. We assessed these assets for impairment in accordance with ASC 360. We valued the assets applying a market method approach utilizing assumptions consistent with similar known and measurable transactions and determined that the carrying amount exceeded the fair value. As a result, we recorded a pre-tax impairment of depreciable properties at June 30, 2016 of

$14 million, in addition to the impairments noted above. The remaining book value of these depreciable assets is approximately $23 million as of December 31, 2016.

Equity investments in unconsolidated subsidiaries

Our Oil and Gas segment owned a 25% interest in a pipeline and gathering system, accounted for under the equity method of accounting. During the second quarter of 2015, due to sustained low commodity prices, recurring operating losses and future expectations we reviewed this investment interest for impairment utilizing the other-than-temporary impairment model under ASC 820, Fair Value Measurements. We valued the investment applying a market method approach utilizing assumptions consistent with similar known and measurable transactions. The carrying amount of this equity method investment exceeded the fair value, and we concluded the decline was considered to be other than temporary. As a result, we recorded a pre-tax impairment loss at June 30, 2015 of $5.2 million, the difference between the carrying amount and the fair value of the investment. In December of 2015, we sold our 25% interest in this pipeline and gathering system.

(14) 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):

	2016	2015	2014
Rent expense	$9,568	$7,177	$6,932

The following is a schedule of future minimum payments required under the operating lease agreements (in thousands):

2017	$6,739
2018	$5,564
2019	$4,441
2020	$2,639
2021	$1,652
Thereafter	$6,245

(15) INCOME TAXES

Income tax expense (benefit) from continuing operations for the years ended December 31 was (in thousands):

	2016	2015	2014
Current:			
Federal	$(23,820)	$2,549	$(2,319)
State	(1,922)	1,319	(1,288)
	(25,742)	3,868	(3,607)
Deferred:			
Federal	36,012	(23,592)	64,780
State	257	(2,323)	5,658
Tax credit amortization	(52)	(113)	(206)
	36,217	(26,028)	70,232
	$10,475	$(22,160)	$66,625

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The temporary differences, which gave rise to the net deferred tax liability, for the years ended December 31 were as follows (in thousands):

	2016	2015
Deferred tax assets:		
Regulatory liabilities	$58,200	$43,586
Employee benefits	29,638	26,400
Federal net operating loss	252,780	217,922
Other deferred tax assets[(a)]	83,485	85,907
Less: Valuation allowance	(9,263)	(4,304)
Total deferred tax assets	414,840	369,511
Deferred tax liabilities:		
Accelerated depreciation, amortization and other property-related differences[(b)]	(820,111)	(711,293)
Regulatory assets	(49,471)	(29,092)
State deferred tax liability	(47,987)	(35,065)
Deferred costs	(18,551)	(26,121)
Other deferred tax liabilities	(14,326)	(18,519)
Total deferred tax liabilities	(950,446)	(820,090)
Net deferred tax liability	$(535,606)	$(450,579)

(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.

(b) To conform with the 2016 presentation of accelerated depreciation, amortization and other property-related differences, 2015 is net of deferred tax assets of $182 million, previously presented as an asset impairment and includes $184 million of a liability previously presented as mining development and oil exploration.

The effective tax rate differs from the federal statutory rate for the years ended December 31, as follows:

	2016	2015	2014
Federal statutory rate [e]	35.0 %	35.0 %	35.0 %
State income tax (net of federal tax effect)	0.2	1.0	1.1
Amortization of excess deferred income taxes and investment tax credits	(0.1)	0.2	(0.1)
Percentage depletion [a]	(8.2)	3.5	(1.0)
Non-controlling interest[d]	(3.6)	—	—
Equity AFUDC	(1.1)	0.3	(0.1)
Tax credits	(1.5)	0.5	(0.1)
Transaction costs	1.1	—	—
Accounting for uncertain tax positions adjustment[b]	(6.0)	(3.5)	(0.1)
Flow-through adjustments [c]	(5.1)	3.8	(0.9)
Other tax differences	0.6	—	(0.1)
	11.3 %	40.8 %	33.7 %

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(a) The tax benefit includes additional percentage depletion deductions that were claimed with respect to the oil and gas properties involving prior tax years. Such deductions were primarily the result of a change in the application of the maximum daily limitation of 1,000 barrels of oil equivalent as allowed under the Internal Revenue Code.

(b) The tax benefit relates to the release of after-tax interest expense that was previously accrued with respect to the liability for uncertain tax positions involving the like-kind exchange transaction effectuated in connection with the IPP Transaction and Aquila Transaction that occurred in 2008. In addition, the tax benefit includes the release of reserves involving research and development credits and deductions. Both adjustments are the result of a re-measurement of the liability for uncertain tax positions predicated on an agreement reached with IRS Appeals in early 2016.

(c) The flow-through adjustments related 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. In addition, flow-through adjustments were recorded related to an accounting method change for tax purposes that allows us to take a current tax deduction for certain indirect 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 tax expense. 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 tax benefits consistent with the flow-through method.

(d) Black Hills Colorado IPP went from a single member LLC, wholly-owned by Black Hills Electric Generation, to a partnership as a result of the sale of 49.9% of its membership interest in April 2016. The effective tax rate reflects the income attributable to the noncontrolling interest for which a tax provision was not recorded.

(e) The effective tax rate for the year ended December 31, 2015 represents a tax benefit due to the pre-tax net loss.

At December 31, 2016, 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	$721,075	2019 to 2036
State Net Operating Loss Carryforward	$616,524	2017 to 2036

As of December 31, 2016, we had a $0.9 million valuation allowance against the state NOL carryforwards. Our 2016 analysis of the ability to utilize such NOLs resulted in a slight increase of the valuation allowance of approximately $0.1 million, which resulted in an increase to tax expense. The valuation allowance adjustment was primarily attributable to a projected decrease in state taxable income for years beyond 2016. 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, 2014	$ 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
Additions for prior year tax positions	3,285
Reductions for prior year tax positions	(3,491)
Additions for current year tax positions	—
Settlements	—
Ending balance at December 31, 2015	31,986
Additions for prior year tax positions	2,423
Reductions for prior year tax positions	(19,174)
Additions for current year tax positions	—
Settlements	(11,643)
Ending balance at December 31, 2016	$ 3,592

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $0.7 million.

As a result of an agreement in principle that was reached with IRS Appeals in the first quarter of 2016, we recognized no interest expense for the year ended December 31, 2016, and approximately $1.8 million and $1.6 million for the years ended December 31, 2015 and 2014, respectively.

We had no accrued interest (before tax effect) associated with income taxes at December 31, 2016, and approximately $13.3 million accrued at December 31, 2015.

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 the IRS in August 2014 related to the like-kind exchange transaction described below and research and development ("R&D") credits and deductions claimed with respect to certain costs and projects. A settlement in principle was reached with IRS Appeals in the first quarter of 2016. We are also currently under examination by the IRS for the 2010 to 2012 tax years. We received a 30-day letter along with Revenue Agent's Report from the IRS in regard to the audit of the 2010 to 2012 tax years. A protest was timely filed with IRS Appeals in the second quarter of 2016 related to R&D credits and deductions claimed with respect to certain costs and projects.

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 had challenged our position with respect to the like-kind exchange. In the first quarter of 2016, we reached a settlement agreement in principle with IRS Appeals related to both the like-kind exchange transaction in addition to the R&D credits and deductions issues. The settlement resulted in a reduction to the liability for unrecognized tax benefits of approximately $29 million excluding interest. Approximately $17 million of the reduction was to restore accumulated deferred income taxes and the remaining portion of approximately $12 million was reclassified to current taxes payable.

As of December 31, 2016, we do not have any tax positions for which it is reasonably possible that the total amount of unrecognized tax benefits will significantly increase or decrease on or before December 31, 2017.

Excess foreign tax credits have been generated and are available to offset United States federal income taxes. At December 31, 2016, we had foreign tax credit carryforwards of approximately $2.3 million, which expire in 2017.

We had a $1.7 million and $0.5 million valuation allowance against the foreign tax credit carryforwards as of December 31, 2016 and 2015 respectively. Approximately $1.8 million of foreign tax credits was previously 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. Subsequent to the settlement agreement in principle that was reached with IRS Appeals in the first quarter of 2016, it has been determined to be more beneficial to deduct the $1.8 million of foreign tax credits. In determining the valuation allowance amount, we compared the tax benefit associated with either deducting foreign taxes or claiming them as credits. The tax benefit of being able to deduct such foreign tax credits is approximately $0.6 million resulting in an increase to the valuation allowance of approximately $1.2 million.

State tax credits have been generated and are available to offset future state income taxes. At December 31, 2016, we had the following state tax credit carryforwards (in thousands):

State Tax Credit Carryforwards		Expiration Year
Investment tax credit	$19,765	2023 to 2036
Research and development	$167	No expiration

As of December 31, 2016, we had a $6.6 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 $3.6 million of which approximately $1.9 million resulted in an increase to tax expense. The remaining $1.7 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 impact of lower projected apportionment factors resulting in decreased state taxable income in years beyond 2016. 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.

(16) OTHER COMPREHENSIVE INCOME

We record deferred gains (losses) in AOCI related to interest rate swaps designated as cash flow hedges, commodity contracts designated as cash flow hedges and the amortization of components of our defined benefit plans. Deferred gains (losses) for our commodity contracts designated as cash flow hedges are recognized in earnings upon settlement, while deferred gains (losses) related to our interest rate swaps are recognized in earnings as they are amortized.

The following table details reclassifications out of AOCI and into net income. The amounts in parentheses below indicate decreases to net income in the Consolidated Statements of Income (Loss) for the period, net of tax (in thousands):

	Location on the Consolidated Statements of Income (Loss)	Amount Reclassified from AOCI	
		December 31, 2016	December 31, 2015
Gains and (losses) on cash flow hedges:			
Interest rate swaps	Interest expense	$(3,899)	$(3,647)
Commodity contracts	Revenue	11,019	14,460
Commodity contracts	Fuel, purchased power and cost of natural gas sold	(14)	—
		7,106	10,813
Income tax	Income tax benefit (expense)	(2,702)	(4,271)
Total reclassification adjustments related to cash flow hedges, net of tax		$4,404	$6,542
Amortization of components of defined benefit plans:			
Prior service cost	Operations and maintenance	$221	$238
Actuarial gain (loss)	Operations and maintenance	(1,978)	(2,822)
		(1,757)	(2,584)
Income tax	Income tax benefit (expense)	533	884
Total reclassification adjustments related to defined benefit plans, net of tax		$(1,224)	$(1,700)
Total reclassifications		$3,180	$4,842

Balances by classification included within AOCI, net of tax 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, 2015	$(341)	$ 7,066	$(15,780)	$(9,055)
Other comprehensive income (loss) before reclassifications	(20,302)	(361)	(1,985)	(22,648)
Amounts reclassified from AOCI	2,534	(6,938)	1,224	(3,180)
As of December 31, 2016	$(18,109)	$ (233)	$(16,541)	$(34,883)

	Derivatives Designated as Cash Flow Hedges			
	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
As of December 31, 2014	$(4,930)	$ 10,023	$(20,137)	$(15,044)
Other comprehensive income (loss) before reclassifications	2,290	5,884	2,657	10,831
Amounts reclassified from AOCI	2,299	(8,841)	1,700	(4,842)
As of December 31, 2015	$(341)	$ 7,066	$(15,780)	$(9,055)

(17) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Years ended December 31,	2016	2015	2014
	(in thousands)		
Non-cash investing activities and financing from continuing operations -			
Property, plant and equipment acquired with accrued liabilities	$29,082	$40,250	$52,584
Increase (decrease) in capitalized assets associated with asset retirement obligations	$8,577	$(518)	$(5,634)
Cash (paid) refunded during the period for continuing operations-			
Interest (net of amount capitalized)	$(112,925)	$(77,810)	$(69,239)
Income taxes, net	$(1,156)	$(1,202)	$(413)

(18) EMPLOYEE BENEFIT PLANS

On February 12, 2016, as disclosed in Note 2, we completed the acquisition of SourceGas, adding an additional defined benefit pension plan, two additional defined benefit healthcare postretirement plans and a 401K retirement savings plan to cover employees of the utilities acquired. Benefits under these plans are determined based on each employee's compensation, years of service, and/or age at retirement, among other factors.

In accordance with accounting standards, the SourceGas benefit liabilities were re-measured as of February 11, 2016. In addition, prior service costs not previously expensed were reclassified to a Regulatory asset and will be amortized over the average remaining service life of the plans.

Amounts recognized in the Condensed Consolidated Balance Sheets upon the February 12, 2016 acquisition are (in thousands):

	Defined Benefit Pension Plan	Non-Pension Defined Benefit Postretirement Plans
Postretirement benefit obligation	$22,187	$ 11,751

Defined Contribution Plans

We sponsor 401(k) retirement savings plans (the 401(k) Plans). Participants in the 401(k) Plans 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) Plans provide employees the opportunity to invest up to 50% of their eligible compensation on a pre-tax or after-tax basis. The 401(k) Plans provide 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.

Defined Benefit Pension Plans (Pension Plans)

During 2016 we maintained three defined benefit pension plans, BHC Pension Plan, Black Hills Utility Holding, Inc. Pension Plan and SourceGas Retirement Plan that as of December 31, 2016 were merged into one single plan, the Black Hills Retirement Plan. The Pension Plans cover certain eligible employees of the Company. 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. All three Pension Plans have been closed to new employees and certain employees who did not meet age and service based criteria.

Black Hills Retirement Plan assets are held in a Master Trust. Due to the plan merger on December 31, 2016, reporting beginning in 2017 will no longer represent 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 rate of return on pension plan assets is based on a targeted asset allocation range determined by the funded ratio of the plan. As of December 31, 2016, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 40% to 50% equity securities and 50% to 60% fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement plan assets is based on the targeted asset allocation range of 30% to 40% equity securities and 60% to 70% fixed-income securities and the expected rate of return from these asset categories. The expected return on plan assets for other postretirement benefits reflects insurance-related investment costs.

The expected long-term rate of return for investments was 6.75% for the BHC Pension Plan and Black Hills Utility Holding, Inc. Plan 2016 and 2015 plan years and 7.5% for the SourceGas Retirement Plan 2016 plan year. Our Pension Plan is funded in compliance with the federal government's funding requirements.

Plan Assets

The percentages of total plan asset fair value by investment category for our Pension Plans at December 31 were as follows:

	2016	2015
Equity	28%	26%
Real estate	5	5
Fixed income	57	59
Cash	2	1
Hedge funds	8	9
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

With the addition of the two SourceGas Postretirement Healthcare Plans, BHC now sponsors five 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 and a Grantor Trust. Effective January 1, 2014, health care coverage for Medicare-eligible retirees is provided through an individual market healthcare exchange for BHC and Black Hills Utility Holdings retirees. SourceGas retirees do not participate in the individual market healthcare exchange; therefore, all permissible health claims are paid under the self-insured plan.

Plan Assets

We fund the Healthcare Plans on a cash basis as benefits are paid. The Black Hills Utility Holding and SourceGas Postretirement - AWG Plans provides for partial pre-funding via VEBAs and a Grantor Trust. Assets related to this pre-funding are held in trust and are for the benefit of the union and non-union employees located in the states of Arkansas, Kansas and Iowa. We do not pre-fund the Healthcare Plans for those employees outside Arkansas, Kansas and Iowa.

Plan Contributions

Contributions to the Pension Plans are cash contributions made directly to the Master Trust. 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):

	2016	2015
Defined Contribution Plan		
Company Retirement Contribution	$9,632	$5,564
Matching contributions	$9,645	$9,616

	2016	2015
Defined Benefit Plans		
Defined Benefit Pension Plans	$14,200	$10,200
Non-Pension Defined Benefit Postretirement Healthcare Plans	$4,965	$3,771
Supplemental Non-Qualified Defined Benefit Plans	$1,565	$1,564

While we do not have required contributions, we expect to make approximately $10 million in contributions to our Defined Benefit Pension Plans in 2017.

Fair Value Measurements

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, 2016				
	Level 1	Level 2	Level 3	NAV [a]	Total
AXA Equitable General Fixed Income	$—	$1,325	$	—	$1,325
Common Collective Trust - Cash and Cash Equivalents	—	5,307	—	—	5,307
Common Collective Trust - Equity	—	101,020	—	—	101,020
Common Collective Trust - Fixed Income	—	209,815	—	—	209,815
Common Collective Trust - Real Estate	—	2,349	—	15,563	17,912
Hedge Funds	—	—	—	29,316	29,316
Total investments measured at fair value	$—	$319,816	$	—$44,879	$364,695

Defined Benefit Pension Plans	December 31, 2015				
	Level 1	Level 2	Level 3	NAV [(a)]	Total
AXA Equitable General Fixed Income	$—	$1,072	$ —	$—	$1,072
Common Collective Trust - Cash and Cash Equivalents	—	1,556	—	—	1,556
Common Collective Trust - Equity	—	74,885	—	—	74,885
Common Collective Trust - Fixed Income	—	172,016	—	—	172,016
Common Collective Trust - Real Estate	—	2,204	—	11,143	13,347
Hedge Funds	—	—	—	25,746	25,746
Total investments measured at fair value	$—	$251,733	$ —	$36,889	$288,622

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(a) Certain investments that are measured at fair value using Net Asset Value "NAV" per share (or its equivalent) for practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in these tables for these investments are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the reconciliation of changes in the plans' benefit obligations and fair value of plan assets above.

Non-pension Defined Benefit Postretirement Healthcare Plans	December 31, 2016			
	Level 1	Level 2	Level 3	Total
Cash and Cash Equivalents	$111	$—	$ —	$111
Equity Securities	1,154	—	—	1,154
Registered Investment Company Trust - Money Market Mutual Fund	—	4,732	—	4,732
Intermediate-term Bond	—	2,473	—	2,473
Total investments measured at fair value	$1,265	$7,205	$ —	$8,470

Non-pension Defined Benefit Postretirement Healthcare Plans	December 31, 2015			
	Level 1	Level 2	Level 3	Total
Registered Investment Company Trust - Money Market Mutual Fund	$—	$4,681	$ —	$4,681
Total investments measured at fair value	$—	$4,681	$ —	$4,681

Additional information about assets of the Benefit Plans, including methods and assumptions used to estimate the fair value of these assets, is as follows:

Cash and Cash Equivalents: This represents an investment in Invesco Treasury Portfolio, which is a short-term investment trust, as well as an investment in Northern Institutional Government Assets Portfolio, which is described as a government money market fund. As shares held reflect quoted prices in an active market, they are categorized as Level 1.

Equity Securities: These represent investments in a combination of equity positions for mainly large cap core allocation and Exchange Trade Funds (EFTs) for diversification into the other sectors of the economy. EFTs are a basket of securities traded like individual stocks on the exchange. Value of equity securities held at year end are based on published market quotations of active markets. The ETF funds can be redeemed on a daily basis at their market price and have no redemption restrictions. As shares held reflect quoted prices in an active market, they are categorized as Level 1.

Intermediate-term bond: This is comprised of a diversified pool of high quality, individual municipal bonds. Pricing is evaluated using multi-dimensional relational models, as well as a series of matrices using Standard Inputs, including Municipal Securities Rule Making Board (MSRB) reported trades and material event notices, plus Municipal Market

Data (MMD) benchmark yields and new issue data. As the models use observable inputs and standard data, the investments are categorized as Level 2.

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. The Plan's investments in the AXA Equitable General Fixed Income Fund are categorized as Level 2.

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. The funds without participant withdrawal limitations are categorized as Level 2.

The following investments are measured at NAV and are not classified in the fair value hierarchy, in accordance with accounting guidance.

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.

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.

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 AOCI (in thousands):

Benefit Obligations

	Defined Benefit Pension Plans		Supplemental Non-qualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2016	2015	2016	2015	2016	2015
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$356,575	$377,772	$40,219	$41,211	$48,077	$49,042
Transfer from SourceGas Acquisition	75,254	—	—	—	15,091	—
Service cost	7,619	6,093	2,099	1,300	1,757	1,808
Interest cost	15,743	15,522	1,257	1,455	1,942	1,801
Actuarial (gain) loss [(a)]	7,001	(28,229)	2,049	(2,072)	2,808	(1,206)
Amendments	—	—	—	—	2,203	—
Benefits paid	(22,013)	(14,583)	(1,755)	(1,675)	(4,965)	(3,771)
Medicare Part D accrued	—	—	—	—	—	(178)
Plan participants' contributions	—	—	—	—	1,110	581
Projected benefit obligation at end of year	$440,179	$356,575	$43,869	$40,219	$68,023	$48,077

(a) Change from 2015 reflects a decrease in the discount rate offset by increased asset returns and a change in the mortality tables used in employee benefit plan estimates.

	Defined Benefit Pension Plans		Supplemental Non-qualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans [(a)]	
	2016	2015	2016	2015	2016	2015
Beginning fair value of plan assets	$288,622	$299,533	$—	$—	$4,681	$4,705
Transfer from SourceGas Acquisition	53,067	—	—	—	3,340	—
Investment income (loss)	30,819	(6,528)	—	—	256	(9)
Employer contributions	14,200	10,200	—	—	4,048	3,175
Retiree contributions	—	—	—	—	1,110	581
Benefits paid	(22,013)	(14,583)	—	—	(4,965)	(3,771)
Plan administrative expenses	—	—	—	—	—	—
Ending fair value of plan assets	$364,695	$288,622	$—	$—	$8,470	$4,681

(a) Assets of VEBAs and Grantor Trust.

The funded status of the plans and the 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	
	2016	2015	2016	2015	2016	2015
Regulatory assets	$66,640	$68,915	$—	$—	$11,401	$6,464
Current liabilities	$—	$—	$1,583	$1,568	$4,360	$3,543
Non-current assets	$—	$—	$—	$—	$21	$23
Non-current liabilities	$75,484	$67,953	$42,286	$38,651	$55,214	$39,855
Regulatory liabilities	$5,195	$—	$—	$—	$3,419	$3,209

Accumulated Benefit Obligation

(in thousands)	Defined Benefit Pension Plans		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2016	2015	2016	2015	2016	2015
Accumulated Benefit Obligation[(a)]	$416,786	$334,923	$32,090	$30,558	$68,023	$48,077

(a) The Defined Benefit Pension Plans Accumulated Benefit Obligation for 2016 represents the obligation for the merged Black Hills Retirement Plan. The 2015 obligation represents the BHC Pension Plan and Black Hills Utility Holding, Inc. Pension Plan and has been combined for presentation purposes to conform to the 2016 merged plan. The Non-pension Defined Benefit Retirement Healthcare Plans Accumulated Benefit Obligation for 2016 represents that obligation for the five postretirement plans maintained by BHC. The 2015 obligation represents the three postretirement plans maintained by BHC.

Components of Net Periodic Expense

(in thousands)	Defined Benefit Pension Plans			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plans		
	2016	2015	2014	2016	2015	2014	2016	2015	2014
Service cost	$7,619	$6,093	$5,448	$1,335	$1,380	$1,498	$1,757	$1,808	$1,700
Interest cost	15,743	15,522	15,852	1,257	1,455	1,447	1,942	1,801	1,919
Expected return on assets	(23,062)	(19,470)	(18,065)	—	—	—	(279)	(131)	(85)
Net amortization of prior service cost	58	58	62	2	2	2	(428)	(428)	(428)
Recognized net actuarial loss (gain)	7,173	11,037	4,806	829	1,081	498	335	408	160
Settlement Expense[(a)]	10	—	—	—	—	—	—	—	—
Net periodic expense	$7,541	$13,240	$8,103	$3,423	$3,918	$3,445	$3,327	$3,458	$3,266

(a) Settlement expense is the result of lump-sum payments on the SourceGas Retirement Plan in excess of interest and service costs for the year.

AOCI

For defined benefit plans, amounts included in AOCI, 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	
	2016	2015	2016	2015	2016	2015
Net (gain) loss	$8,472	$8,777	$7,132	$6,339	$1,595	$1,704
Prior service cost (gain)	31	41	5	6	(694)	(1,087)
Total AOCI	$8,503	$8,818	$7,137	$6,345	$901	$617

The amounts in AOCI, Regulatory assets or Regulatory liabilities, after-tax, expected to be recognized as a component of net periodic benefit cost during calendar year 2017 are as follows (in thousands):

	Defined Benefit Pension Plans	Supplemental Non-qualified Defined Benefit Plans	Non-pension Defined Benefit Postretirement Healthcare Plans
Net loss	$ 2,604	$ 572	$ 325
Prior service cost (credit)	38	1	(368)
Total net periodic benefit cost expected to be recognized during calendar year 2017	$ 2,642	$ 573	$ (43)

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:	2016	2015	2014	2016	2015	2014	2016	2015	2014
Discount rate	4.27%	4.58%	4.19%	4.02%	4.28%	4.19%	3.96%	4.17%	3.82%
Rate of increase in compensation levels	3.47%	3.51%	3.76%	5.00%	5.00%	5.00%	N/A	N/A	N/A

	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:	2016	2015	2014	2016	2015	2014	2016	2015	2014
Discount rate [(a)]	4.50%	4.19%	5.04%	4.28%	4.19%	5.03%	4.18%	3.82%	4.46%
Expected long-term rate of return on assets [(b)]	6.87%	6.75%	6.75%	N/A	N/A	N/A	3.83%	3.00%	2.00%
Rate of increase in compensation levels	3.42%	3.76%	3.76%	5.00%	5.00%	5.00%	N/A	N/A	N/A

(a) The estimated discount rate for the merged Black Hills Retirement Plan is 4.27% for the calculation of the 2017 net periodic pension costs.
(b) The expected rate of return on plan assets is 6.75% for the calculation of the 2017 net periodic pension cost.

The healthcare benefit obligation was determined at December 31 as follows:

	2016 [(a)]	2015
Trend Rate - Medical		
Pre-65 for next year - All Plans	6.10%	6.35%
Pre-65 Ultimate trend rate - Black Hills Corp	4.50%	4.50%
Trend Year	2024	2024
Post-65 for next year - All Plans	5.10%	5.20%
Post-65 Ultimate trend rate - Black Hills Corp	4.50%	4.50%
Trend Year	2023	2023

(a) The 2016 Medical Trend Rates include the two additional non-pension defined benefit postretirement plans from SourceGas.

We do not pre-fund our supplemental plans or three of the five healthcare plans. The table below shows the expected impacts of an increase or decrease to our healthcare trend rate for our Healthcare Plans (in thousands):

Change in Assumed Trend Rate	Impact on December 31, 2016 Accumulated Postretirement Benefit Obligation	Impact on 2017 Service and Interest Cost
Increase 1%	$ 2,569	$ 156
Decrease 1%	$ (2,191)	$ (131)

Beginning in 2016, the Company changed the method used to estimate the service and interest cost components of the net periodic pension, supplemental non-qualified defined benefit and other postretirement benefit costs. The new method uses the spot yield curve approach to estimate the service and interest costs by applying the specific spot rates along the yield curve used to determine the benefit obligations to relevant projected cash outflows. Previously, those costs were determined using a single weighted-average discount rate. The change does not affect the measurement of the total benefit obligations as the change in service and interest costs offsets the actuarial gains and losses recorded in other comprehensive income. The new method provides a more precise measure of interest and service costs by improving the correlation between the projected benefit cash flows and the discrete spot yield curve rates. The Company accounted for this change as a change in estimate prospectively beginning in the first quarter of 2016. See “Pension and Postretirement Benefit Obligations” within our Critical Accounting Policies in Item 7 on Form 10-K for additional details.

The following benefit payments, which reflect future service, are expected to be paid (in thousands):

	Defined Benefit Pension Plan	Supplemental Non-qualified Defined Benefit Plans	Non-Pension Defined Benefit Postretirement Healthcare Plans
2017	$21,355	$ 1,583	$ 5,504
2018	$21,566	$ 1,809	$ 5,779

2019	$23,010	$ 1,921	$ 5,886
2020	$27,028	$ 1,634	$ 5,983
2021	$27,614	$ 1,836	$ 5,931
2022-2026	$149,893	$ 11,009	$ 27,585

(19) 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.

- South Dakota Electric'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.

- South Dakota Electric 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.

- Wyoming Electric'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 Wyoming Electric. Under a separate inter-company agreement, Wyoming Electric sells 50% of the facility output to South Dakota Electric.

- Wyoming Electric'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, Wyoming Electric has agreed to sell 20 MW of energy from Silver Sage to South Dakota Electric.

- Colorado Electric's REPA with AltaGas expiring October 16, 2037, provides up to 14.5 MW of wind energy from the Busch Ranch Wind Farm 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):

	2016	2015	2014
PPA with PacifiCorp	$12,221	$13,990	$13,943
Transmission services agreement with PacifiCorp	$1,428	$1,213	$1,227
PPA with Happy Jack	$3,836	$3,155	$3,919
PPA with Silver Sage	$4,949	$4,107	$4,798
Busch Ranch Wind Farm	$2,071	$1,734	$1,998
PPAs with Cargill [(a)]	$10,995	$16,112	$9,286

(a) PPAs with Cargill expired on December 31, 2016.

Other Gas Supply Agreements

Our Utilities also purchase natural gas, including transportation and storage capacity to meet customers' needs, under short-term and long-term purchase contracts. These contracts extend to 2044.

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 10 year agreement expiring in 2024 became effective in first quarter of 2014 upon completion of the processing infrastructure capable of handling the committed volumes.

Purchase Commitments

We maintain natural gas supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated baseload gas volumes are established prior to the beginning of the month under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month based on requirements in accordance with the terms of the individual contract.

Our Gas Utilities segment has commitments to purchase physical quantities of natural gas under contracts indexed to various forward natural gas price curves. A portion of our gas purchases are purchased under evergreen contracts and are therefore, for purposes of this disclosure, carried out for 60 days. At December 31, 2016, the long-term commitments to purchase quantities of natural gas under contracts indexed to the following forward indices were as follows (in MMBtus):

	CIG Rockies	Enable-East	NWPL-Wyoming	SSTAR-TEXOK	Other
2017	5,549,427	620,300	1,208,000	457,399	44,913
2018	—	584,000	1,208,000	—	—
2019	—	584,000	720,000	—	—
2020	—	585,600	—	—	—
2021	—	388,800	—	—	—

Purchases under these contracts totaled $31 million, $48 million and $31 million for 2016, 2015 and 2014, respectively.

The following is a schedule of unconditional purchase obligations required under the power purchase, transmission services, gathering commitments, coal and natural gas transportation and storage agreements (in thousands):

	Power Purchase Agreements	Transportation, storage, gathering and coal agreements
2017	$ 26,690	$ 136,607
2018	$ 8,934	$ 120,123
2019	$ 6,388	$ 87,210
2020	$ 6,388	$ 82,247
2021	$ 5,755	$ 75,424
Thereafter	$ 11,509	$ 225,765

Future Purchase Agreement - Related Party

Wyoming Electric’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 Wyoming Electric 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. The purchase option would be subject to WPSC and FERC approval in order to obtain regulatory treatment.

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.

- South Dakota Electric 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, South Dakota Electric will also provide the City of Gillette their operating component of spinning reserves.

- South Dakota Electric 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.

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 Wyoming Electric 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 Wyoming Electric'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, hazardous air pollutants, 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 2046.

The EPA issued the Industrial and Commercial Boiler Regulations for Area Sources of Hazardous Air Pollutants, with updates which imposed 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 following the closure certification date.

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 following the closure certification date.

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 $4.1 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 8 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 $1.5 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 was a potential for additional minimal remediation work at Plattsmouth where monitoring was required until 2015. Both Nebraska sites were required to monitor groundwater quality for a minimum two year period, ending in 2015. In late 2015, groundwater concentrations were proposed and approved by the Nebraska Department of Environmental Quality as meeting steady or declining pollution levels. We assembled our final removal action completion reports to formally close the site, and submitted reports to the Nebraska Department of Environmental Quality in December 2015. In 2016, we received state approval for “no further action” at both sites.

As of December 31, 2016, our estimated liabilities for Iowa’s MGP sites currently range from approximately $2.6 million to $6.1 million for which we had $2.6 million accrued for remediation of sites as of December 31, 2016 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.

As a result of the SourceGas Transaction, we acquired potential liability for at least one former MGP site in McCook, Nebraska. The Nebraska Department of Environmental Quality conducted a limited assessment in 2012 which documented soil and groundwater impacts. However, there has been no directive from the state to pursue either remediation or further assessment. We are currently evaluating the potential for other Potential Responsible Parties and future comprehensive analysis to fully determine and delineate the extent of contamination. The assigned liability for this site cannot be determined at this time. However, based on the state's assessment, we anticipate costs will be less than $1.0 million.

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.

(20) 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 and a contract performance guarantee.

We had the following guarantees in place as of (in thousands):

Nature of Guarantee	Maximum Exposure at December 31, 2016	Expiration
Indemnification for subsidiary reclamation/surety bonds [(a)]	$ 57,105	Ongoing
	$ 57,105	

(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.

(21) OIL AND GAS RESERVES (Unaudited)

BHEP has operating and non-operating interests in 713 gross developed oil and gas wells in 9 states and holds leases on approximately 127,919 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):

	2016	2015	2014
Acquisition of properties:			
Proved	$—	$1,407	$4,881
Unproved	910	669	5,056
Exploration costs	1,102	35,434	54,355
Development costs	4,657	128,998	52,262
Asset retirement obligations incurred	—	566	68
Total costs incurred	$6,669	$167,074	$116,622

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, 2016, 2015 and 2014 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.

	2016			2015			2014		
	Oil	Gas	NGL	Oil	Gas	NGL	Oil	Gas	NGL
	(in Mbbls of oil and NGL, and MMcf of gas)								
Proved developed and undeveloped reserves:									
Balance at beginning of year	3,450	73,412	1,752	4,276	65,440	1,720	3,921	63,190	—
Production [(a)]	(319)	(9,430)	(133)	(371)	(10,058)	(102)	(337)	(7,156)	(135)
Sales	(570)	(1,291)	(17)	(11)	(828)	—	(40)	(61)	—
Additions - extensions and discoveries	3	52	—	199	24,462	232	733	11,003	182
Revisions to previous estimates	(322)	(8,173)	110	(643)	(5,604)	(98)	(1)	(1,536)	1,673
Balance at end of year	2,242	54,570	1,712	3,450	73,412	1,752	4,276	65,440	1,720
Proved developed reserves at end of year included above	2,242	54,570	1,712	3,436	73,390	1,752	3,780	57,427	1,530
Proved undeveloped reserves at the end of year included in above	—	—	—	14	22	—	496	8,013	191
NYMEX prices	$42.75	$2.48	$— [(b)]	$50.28	$2.59	$— [(b)]	$94.99	$4.35	$— [(b)]
Well-head reserve prices[(c)]	$37.35	$2.25	$11.92	$44.72	$1.27	$18.96	$85.80	$3.33	$34.81

(a) Production for reserve calculations does not include volumes for natural gas liquids (NGLs) for historical periods.

(b) A specific NYMEX price for NGL is not available. Market prices for NGL are broken down by various liquid components, including ethane, propane, isobutane, 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.

(c) For reserves purposes, costs to gather gas previously netted from the gas price were reclassified into operating expenses in 2016, with approximate rates of $1.54/Mcf for Piceance, $0.92/Mcf for San Juan and $0.53/Mcf for all others. For accounting purposes, consistent with prior years, the sales price for natural gas is adjusted for transportation costs and other related deductions when applicable, as further described in Note 1 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Reserve additions for 2016 totaled 0.1 Bcfe, replacing 0% of annual production. Reserve additions in 2016 were minimal due to continued poor economic conditions and our focus on supporting utility Cost of Service Gas Programs, which together, limited any further drilling. Capital spending in 2016 was primarily for existing infrastructure and acquiring right-aways. Future capital spending rates will be dependent on product prices, processing availability and support of our Cost of Service Gas program.

In 2016, we had negative revisions of (9.4 Bcfe) to previous reserve estimates. Most of the negative revision was the result of lower equivalent prices of oil, liquids and gas received at the wellhead of (12.3 Bcfe), partially offset by improved wellhead performance of 3.5 Bcfe.

SEC regulations require that PUD locations meet the test of being developed within five years of being categorized as proved. In 2016, we had no PUD locations that were required to be dropped because of the five year rule.

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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.

- We have no PUDs at December 31, 2016, and due to economic conditions in 2016, no new gross PUD locations were added for future drilling in the Piceance Mancos or Powder River Basin.

- 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, 2016 were:

	Proved Reserves (in Bcfe)	Gross PUD Locations	Future Development Costs (in millions)
Existing 2015:			
Williston	0.1	6	$ 0.5
Piceance	—	—	$ (0.1)
Powder River	—	—	$ —
Year End Total 2015	0.1	6	$ 0.4
Dropped 2016:			
Williston	(0.1)	(6)	$ (0.5)
Piceance	—	—	$ 0.1
	(0.1)	(6)	$ (0.4)
Drilled in 2016:			
	—	—	$ —
Revisions:	—	—	$ —
Added in 2016:	—	—	$ —
Total Proved Undeveloped	—	—	$ —

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Capitalized Costs

Following is information concerning capitalized costs for the years ended December 31 (in thousands):

	2016	2015	2014
Unproved oil and gas properties	$ 18,547	$47,254	$75,329
Proved oil and gas properties	1,043,558	1,008,466	807,518
Gross capitalized costs	1,062,105	1,055,720	882,847
Accumulated depreciation, depletion and amortization and valuation allowances	(1,000,091)	(888,775)	(612,012)
Net capitalized costs	$ 62,014	$166,945	$270,835

Results of Operations

Following is a summary of results of operations for producing activities for the years ended December 31 (in thousands):

	2016	2015	2014
Revenue	$34,058	$43,283	$55,114
Production costs	17,231	19,762	22,155
Depreciation, depletion and amortization	12,574	28,062	23,288
Impairment of long-lived assets	106,957	249,608	—
Total costs	136,762	297,432	45,443
Results of operations from producing activities before tax	(102,704)	(254,149)	9,671
Income tax benefit (expense)	37,916	93,743	(3,415)
Results of operations from producing activities (excluding general and administrative costs and interest costs)	$(64,788)	$(160,406)	$6,256

Unproved Properties

Unproved properties not subject to amortization at December 31, 2016, relate primarily to direct purchase leasehold and work-in-progress projects. Unproved properties not subject to amortization at December 31, 2015 and 2014 consisted mainly of exploration costs 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 $0.9 million, $1.0 million and $1.0 million of interest during 2016, 2015 and 2014, 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.

The table below sets forth the cost of unproved properties excluded from the amortization base as of December 31, 2016 and notes the year in which the associated costs were incurred (in thousands):

	2016	2015	2014	Prior	Total
Leasehold acquisition cost	$963	$—	$—	$9,278	$10,241
Exploration cost	532	441	6,443	—	7,416
Capitalized interest	50	23	335	482	890
Total	$1,545	$464	$6,778	$9,760	$18,547

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):

	2016	2015	2014
Future cash inflows	$246,221	$295,173	$675,973
Future production costs	(166,248)	(146,552)	(245,180)
Future development costs, including plugging and abandonment	(18,333)	(24,833)	(45,123)
Future income tax expense	—	—	(29,523)
Future net cash flows	61,640	123,788	356,147
10% annual discount for estimated timing of cash flows	(26,574)	(44,760)	(173,125)
Standardized measure of discounted future net cash flows	$35,066	$79,028	$183,022

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):

	2016	2015	2014
Standardized measure - beginning of year	$79,028	$183,022	$159,425
Sales and transfers of oil and gas produced, net of production costs	(4,314)	(29,948)	(32,139)
Net changes in prices and production costs	(32,698)	(127,199)	(28,544)
Extensions, discoveries and improved recovery, less related costs	—	15,718	17,582
Changes in future development costs	1,825	(7,387)	3,195
Development costs incurred during the period	—	27,211	2,079
Revisions of previous quantity estimates	(7,477)	(6,941)	23,722
Accretion of discount	7,903	18,870	18,437
Net change in income taxes	—	5,682	19,265
Purchases of reserves	—	—	—
Sales of reserves	(9,201)	—	—
Standardized measure - end of year	$35,066	$79,028	$183,022

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.

(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 2016 and 2015.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2016				
Revenue	$449,959	$325,441	$333,786	$463,788
Operating income (loss)	$73,590	$35,298	$58,409	$55,289
Net Income (loss)	$40,050	$3,283	$17,884	$21,414
Net income (loss) available for common stock	$40,002	$669	$14,131	$18,168
Earnings (loss) per share - Basic	$0.78	$0.01	$0.27	$0.34
Earnings (loss) per share - Diluted	$0.77	$0.01	$0.26	$0.33
Dividends paid per share	$0.420	$0.420	$0.420	$0.420
Common stock prices - High	$61.13	$63.53	$64.58	$62.83
Common stock prices - Low	$44.65	$56.16	$56.86	$54.76

All quarters of 2016 included non-cash impairments of oil and gas properties and external incremental acquisition and transaction costs. We recorded after-tax impairments of oil and gas properties of $8.8 million during the first quarter, $16 million during the second quarter, $7.9 million during the third quarter and $34 million during the fourth quarter. We incurred after-tax external incremental acquisition and transaction expenses of $15 million during the first quarter, $4.1 million during the second quarter, $4.1 million during the third quarter and $5.5 million during the fourth quarter.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2015				
Revenue	$441,987	$272,254	$272,105	$318,259
Operating income (loss)	$70,500	$(38,858)	$(2,044)	$197
Net Income (loss)	$33,850	$(41,842)	$(9,943)	$(14,176)
Net income (loss) available for common stock	$33,850	$(41,842)	$(9,943)	$(14,176)
Earnings (loss) per share - Basic	$0.76	$(0.94)	$(0.22)	$(0.30)
Earnings (loss) per share - Diluted	$0.76	$(0.94)	$(0.22)	$(0.30)
Dividends paid per share	$0.405	$0.405	$0.405	$0.405
Common stock prices - High	$53.37	$52.96	$47.27	$47.51
Common stock prices - Low	$47.88	$43.48	$36.81	$40.00

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All quarters of 2015 included non-cash impairments of oil and gas properties. We incurred external incremental acquisition and transaction costs during the second, third and fourth quarters. We recorded after-tax impairments of oil and gas properties of $14 million during the first quarter, $66 million during the second quarter, $36 million during the third quarter and $44 million during the fourth quarter. We incurred after-tax external incremental acquisition and transaction expenses of $0.5 million during the second quarter, $2.8 million during the third quarter and $3.7 million during the fourth quarter.

(23) SUBSEQUENT EVENTS

None.

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, 2016. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Security Exchange Act of 1934, as amended, is recorded, processed, summarized and reported, within the time periods specified in the Commission’s rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the year ended December 31, 2016, the Company completed the acquisition of SourceGas, which is integrated within the Company’s Gas Utilities operations. As part of our ongoing integration activities, we are continuing to incorporate our controls and procedures into SourceGas and to implement company-wide controls over its operations. Other than the changes due to the SourceGas acquisition, there were no changes in the Company’s internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

Management’s Report on Internal Control over Financial Reporting is presented on Page 123 of this Annual Report on Form 10-K.

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 2017 Annual Meeting of Shareholders, which is incorporated herein by reference.

Executive Officers

David R. Emery, age 54, has been Chairman and Chief Executive Officer since January 2016 and Chairman, President and Chief Executive Officer from 2005 through 2015. Prior to that, he held various positions with the Company, including President and Chief Executive Officer and member of the Board of Directors from 2004 to 2005, President and Chief Operating Officer — Retail Business Segment from 2003 to 2004 and Vice President — Fuel Resources from 1997 to 2003. Mr. Emery has 27 years of experience with the Company.

Scott A. Buchholz, age 55, has been our Senior Vice President — Chief Information Officer since the closing of the Aquila Transaction in 2008. Prior to joining the Company, he was Aquila's Vice President of Information Technology from 2005 until 2008, Six Sigma Deployment Leader/Black Belt from 2004 until 2005, and General Manager, Corporate Information Technology from 2002 until 2004. Mr. Buchholz has 36 years of experience with the Company, including 28 years with Aquila.

Linden R. Evans, age 54, has been President and Chief Operating Officer of the Company since January 2016 and President and Chief Operating Officer — Utilities from 2004 through 2015. Mr. Evans served as the Vice President and General Manager of our former communication subsidiary in 2003 and 2004, and served as our Associate Counsel from 2001 to 2003. Mr. Evans has 15 years of experience with the Company.

Brian G. Iverson, age 54, has been Senior Vice President, General Counsel and Chief Compliance Officer since April 2016. He served as Senior Vice President - Regulatory and Governmental Affairs and Assistant General Counsel from 2014 to April 2016, Vice President and Treasurer from 2011 to 2014, Vice President - Electric Regulatory Services from 2008 to 2011 and as Corporate Counsel from 2004 to 2008. Mr. Iverson has 13 years of experience with the Company.

Richard W. Kinzley, age 51, has been Senior Vice President and Chief Financial Officer since January 2015. He served as Vice President - Corporate Controller from 2013 to 2014, Vice President - Strategic Planning and Development from 2008 to 2013, and as Director of Corporate Development from 2000 to 2008. Mr. Kinzley has 17 years of experience with the Company.

Jennifer C. Landis, age 42, has been Senior Vice President - Chief Human Resources Officer since February 1, 2017. She served as Vice President of Human Resources from April 2016 through January 2017, Director of Corporate Human Resources and Talent Management from March 2013 to April 2016, and Director of Organization Development from October 2008 to February 2013. Ms. Landis has 15 years of experience with the Company.

Robert A. Myers, age 59, has been Senior Vice President since February 1, 2017. He served as our Senior Vice President — Chief Human Resource Officer from 2009 to February 2017 and served as our Interim Human Resources Executive in 2008. He was a partner with Strategic Talent Solutions, a human resources consulting firm, from 2006 until 2008, Senior Vice President — Chief Human Resource Officer for Devon Energy in 2006, and Senior Vice President and Chief Human Resource Officer at Reebok International, Ltd from 2003 until 2006. He has over 35 years of service in key human resources leadership roles. Mr. Myers has 8 years of experience with the Company and plans to retire effective April 1, 2017.

ITEM 11. EXECUTIVE COMPENSATION

Information required under this item is set forth in the Proxy Statement for our 2017 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 2017 Annual Meeting of Shareholders, which is incorporated herein by reference.

EQUITY COMPENSATION PLAN INFORMATION

The following table includes information as of December 31, 2016 with respect to our equity compensation plans. These plans include the 2005 Omnibus Incentive plan and 2015 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	255,065 (1)	$ 45.51 (1)	1,115,557 (2)
Equity compensation plans not approved by security holders	—	$ —	—
Total	255,065	$ 45.51	1,115,557

(1) Includes 135,650 full value awards outstanding as of December 31, 2016, comprised of restricted stock units, performance shares, short-term incentive plan (STIP) units and Director common stock units. The weighted average exercise price does not include the restricted stock units, performance shares, STIP or common stock units. In addition, 293,095 shares of unvested restricted stock were outstanding as of December 31, 2016, which are not included in the above table because they have already been issued.

(2) Shares available for issuance are from the 2015 Omnibus Incentive Plan. The 2015 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 2017 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 2017 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, 2016, 2015 and 2014

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, 2016, 2015 AND 2014

Description	Balance at Beginning of Year	Adjustments (a)	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:						
2016	$1,741	$ 2,158	$ 2,704	$ 4,915	$ (9,126)	$2,392
2015	$1,516	$ —	$ 3,860	$ 4,132	$ (7,767)	$1,741
2014	$1,237	$ —	$ 4,470	$ 4,233	$ (8,424)	$1,516

(a) Represents allowance balances added with the SourceGas acquisition.

3. Exhibits

Exhibit Number	Description
2.1*	Purchase and Sale Agreement by and among Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, as Sellers, and Black Hills Utility Holdings, Inc., as Buyer, dated as of July 12, 2015 (filed as Exhibit 2.1 to the Registrant's Form 8-K filed on July 14, 2015).
2.2*	First Amendment to Purchase and Sale Agreement effective December 10, 2015, by and among, Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, as Sellers, and Black Hills Utility Holdings, Inc., as Buyer (filed as Exhibit 2.2 to the Registrant's Form 10-K for 2015).
2.3*	Option Agreement, by and among, Aircraft Services Corporation, as ASC, SourceGas Holdings LLC, as the Company and Black Hills Utility Holdings, Inc., as Buyer (filed as Exhibit 2.2 to the Registrant's Form 8-K filed on July 14, 2015).
2.4*	Guaranty of Black Hills Corporation in favor of Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, dated as of July 12, 2015 (filed as Exhibit 2.3 to the Registrant's Form 8-K filed on July 14, 2015).
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). Fifth Supplemental Indenture dated as of January 13, 2016 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on January 13, 2016).
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*	Junior Subordinated Indenture dated as of November 23, 2015 between Black Hills Corporation and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on November 23, 2015). First Supplemental Indenture dated as of November 23, 2015 (filed as Exhibit 4.2 to the Registrant's Form 8-K filed on November 23, 2015).

4.5*	Purchase Contract and Pledge Agreement dated as of November 23, 2015 between Black Hills Corporation and U.S. Bank National Association, as purchase contract agent, collateral agent, custodial agent and securities intermediary (filed as Exhibit 4.4 to the Registrant's Form 8-K filed on November 23, 2015).
4.6*	Indenture dated as of April 16, 2007 between SourceGas LLC and U.S. Bank National Association, as Trustee (relating to $325 million, 5.90% Senior Notes due 2017 - $0 balance remaining at 12/31/2016) (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on March 18, 2016).
4.7*	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*†	Black Hills Corporation 2015 Omnibus Incentive Plan (filed as Appendix B to the Registrant's Proxy Statement filed March 19, 2015).
10.7*†	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). Form of Stock Option Agreement effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.8 to Registrant's Form 10-K for 2015).
10.8*†	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). Form of Restricted Stock Award Agreement effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.10 to Registrant's Form 10-K for 2015).
10.9*†	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). Form of Restricted Stock Unit Award Agreement for 2015 Omnibus Plan effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.12 to the Registrant's Form 10-K for 2015).

10.10*†	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). Form of Performance Share Award Agreement effective for awards granted on or after January 1, 2015 (filed as Exhibit 10.11 to the Registrant's Form 10-K for 2014). Form of Performance Share Award Agreement effective for awards granted on or after January 1, 2016 (filed as Exhibit 10.6 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016).
10.11*†	Form of Short-term Incentive effective for awards granted on or after January 1, 2016 (filed as Exhibit 10.7 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016).
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, 2016 between Black Hills Corporation and David R. Emery (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on November 16, 2016).
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 16, 2016).
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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*	Third Amended and Restated Term Loan Credit Agreement, dated August 9, 2016 (relating to $340 million SourceGas Acquisition Credit Agreement - $0 balance at 12/31/2016) among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and J.P. Morgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on August 10, 2016).
10.21*	Second Amended and Restated Credit Agreement, dated August 9, 2016 (relating to $750 million Revolving Credit Facility), among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and U.S. Bank, National Association, as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on August 10, 2016).
10.22	Amendment No. 1 to Second Amended and Restated Credit Agreement dated as of December 7, 2016 (relating to $750 million Revolving Credit Facility).
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	Credit Agreement dated April 13, 2015 (relating to $300 million, two-year term loan - $0 balance at 12/31/2016), among Black Hills Corporation, as Borrower, JPMorgan 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 April 14, 2015). First Amendment dated August 6, 2015 (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on August 12, 2015).
10.24*	Credit Agreement dated August 9, 2016 (relating to $500 million, three-year term loan - $400 million balance at 12/31/2016), among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on August 10, 2016).
10.25	Amendment No. 1 to Credit Agreement dated as of December 7, 2016 (relating to $500 million, three-year term loan - $400 million balance as of 12/31/2016).

10.26*	Note Purchase Agreement dated September 29, 2014 among SourceGas Holdings LLC and the purchasers party thereto (relating to $95 million 3.98% Senior Secured Notes due 2019 - $0 balance at 12/31/2016) (filed as Exhibit 10.2 to the Registrant’s Form 8-K filed on March 18, 2016).
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10.29*	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).
10.30*	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).
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23.1	Consent of Independent Registered Public Accounting Firm.
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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.
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101	Financial Statements in XBRL Format

* 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.

ITEM 16. FORM 10-K SUMMARY

None.

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 and Chief Executive Officer

Dated: February 24, 2017

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 and Chief Executive Officer	Director and Principal Executive Officer	February 24, 2017
/S/ RICHARD W. KINZLEY Richard W. Kinzley, Senior Vice President and Chief Financial Officer	Principal Financial and Accounting Officer	February 24, 2017
/S/ MICHAEL H. MADISON Michael H. Madison	Director	February 24, 2017
/S/ LINDA K. MASSMAN Linda K. Massman	Director	February 24, 2017
/S/ STEVEN R. MILLS Steven R. Mills	Director	February 24, 2017
/S/ ROBERT P. OTTO Robert P. Otto	Director	February 24, 2017
/S/ REBECCA B. ROBERTS Rebecca B. Roberts	Director	February 24, 2017
/S/ MARK A. SCHOBER Mark A. Schober	Director	February 24, 2017
/S/ TERESA A. TAYLOR Teresa A. Taylor	Director	February 24, 2017
/S/ JOHN B. VERING John B. Vering	Director	February 24, 2017
/S/ THOMAS J. ZELLER Thomas J. Zeller	Director	February 24, 2017

INDEX TO EXHIBITS

Exhibit Number	Description
2.1*	Purchase and Sale Agreement by and among Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, as Sellers, and Black Hills Utility Holdings, Inc., as Buyer, dated as of July 12, 2015 (filed as Exhibit 2.1 to the Registrant's Form 8-K filed on July 14, 2015).
2.2*	First Amendment to Purchase and Sale Agreement effective December 10, 2015, by and among, Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, as Sellers, and Black Hills Utility Holdings, Inc., as Buyer (filed as Exhibit 2.2 to the Registrant’s Form 10-K for 2015).
2.3*	Option Agreement, by and among, Aircraft Services Corporation, as ASC, SourceGas Holdings LLC, as the Company and Black Hills Utility Holdings, Inc., as Buyer (filed as Exhibit 2.2 to the Registrant's Form 8-K filed on July 14, 2015).
2.4*	Guaranty of Black Hills Corporation in favor of Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, dated as of July 12, 2015 (filed as Exhibit 2.3 to the Registrant's Form 8-K filed on July 14, 2015).
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). Fifth Supplemental Indenture dated as of January 13, 2016 (filed as Exhibit 4.1 to the Registrant’s Form 8-K filed on January 13, 2016).
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*	Junior Subordinated Indenture dated as of November 23, 2015 between Black Hills Corporation and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on November 23, 2015). First Supplemental Indenture dated as of November 23, 2015 (filed as Exhibit 4.2 to the Registrant's Form 8-K filed on November 23, 2015).

4.5*	Purchase Contract and Pledge Agreement dated as of November 23, 2015 between Black Hills Corporation and U.S. Bank National Association, as purchase contract agent, collateral agent, custodial agent and securities intermediary (filed as Exhibit 4.4 to the Registrant’s Form 8-K filed on November 23, 2015).
4.6*	Indenture dated as of April 16, 2007 between SourceGas LLC and U.S. Bank National Association, as Trustee (relating to $325 million, 5.90% Senior Notes due 2017 - $0 balance remaining at 12/31/2016) (filed as Exhibit 10.1 to the Registrant’s Form 8-K filed on March 18, 2016).
4.7*	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*†	Black Hills Corporation 2015 Omnibus Incentive Plan (filed as Appendix B to the Registrant’s Proxy Statement filed March 19, 2015).
10.7*†	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). Form of Stock Option Agreement effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.8 to Registrant’s Form 10-K for 2015).
10.8*†	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). Form of Restricted Stock Award Agreement effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.10 to Registrant’s Form 10-K for 2015).
10.9*†	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). Form of Restricted Stock Unit Award Agreement for 2015 Omnibus Plan effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.12 to the Registrant’s Form 10-K for 2015).

10.10*†	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). Form of Performance Share Award Agreement effective for awards granted on or after January 1, 2015 (filed as Exhibit 10.11 to the Registrant's Form 10-K for 2014). Form of Performance Share Award Agreement effective for awards granted on or after January 1, 2016 (filed as Exhibit 10.6 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016).
10.11*†	Form of Short-Term Incentive effective for awards granted on or after January 1, 2016 (filed as Exhibit 10.7 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016).
10.12*†	Form of Indemnification Agreement (filed as Exhibit 10.5 to the Registrant's Form 8-K filed on September 3, 2004).

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