BLACK HILLS CORP /SD/
Form 10-K
February 25, 2016

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, 2015

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ____________________ to ___________________

Commission File Number 001-31303

BLACK HILLS CORPORATION

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

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

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

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

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

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

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

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

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

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

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

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

Yes o No x

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

At June 30, 2015 $1,925,452,517

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, 2016
Common stock, $1.00 par value	51,194,387 shares

Documents Incorporated by Reference

Portions of the Registrant's Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2016 Annual Meeting of Stockholders to be held on April 26, 2016, 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
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.
BHSC	Black Hills Service Company LLC, a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Colorado IPP	Black Hills Colorado IPP, LLC a direct wholly-owned subsidiary of Black Hills Electric Generation
Black Hills Energy	The name used to conduct the business of Black Hills Utility Holdings, Inc., and its subsidiaries
Black Hills Electric Generation	Black Hills Electric Generation, LLC, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
BLM	United States Bureau of Land Management
Btu	British thermal unit
Busch Ranch	Busch Ranch Wind Farm
Ceiling Test	Related to our Oil and Gas segment, 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, with consideration of price changes only to the extent provided by contractual arrangements, attributable to proved natural gas, crude oil and NGL reserves using a discount rate defined by the SEC plus the cost of properties not being amortized, plus the lower of cost or estimated fair value of unevaluated

	properties included in the cost being amortized, less income tax effects related to differences between the book and tax basis of the excluded properties and unevaluated properties included in the amortization base.
CFTC	United States Commodity Futures Trading Commission
CG&A	Cawley, Gillespie & Associates, Inc., an independent consulting and engineering firm
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation

Cheyenne Prairie	Cheyenne Prairie Generating Station is a 132 MW natural-gas fired generating facility jointly owned by Black Hills Power and Cheyenne Light in Cheyenne, Wyoming. Cheyenne Prairie was placed into commercial service on October 1, 2014.
City of Gillette	The City of Gillette, Wyoming, affiliate of the JPB. The JPB financed the purchase of 23% of Wygen III power plant for the City of Gillette.
CO_2	Carbon dioxide
Colorado Electric	Black Hills Colorado Electric Utility Company, LP (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings
Colorado Gas	Black Hills Colorado Gas Utility Company, LP (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings
Cooling Degree Day	A cooling degree day is equivalent to each degree that the average of the high and low temperature for a day is above 65 degrees. The warmer the climate, the greater the number of cooling degree days. Cooling degree days are used in the utility industry to measure the relative warmth of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30 year average.
Cost of Service Gas Program	A program our utility subsidiaries submitted applications for with respective state utility regulators in Iowa, Kansas, Nebraska, South Dakota, Colorado and Wyoming, seeking approval for a 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
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
De-designated interest rate swaps	The $250 million notional amount interest rate swaps that were originally designated as cash flow hedges under the accounting for derivatives and hedges but subsequently de-designated in December 2008. These swaps were settled in November 2013.
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DSM	Demand Side Management
DRSPP	Dividend Reinvestment and Stock Purchase Plan
Dth	Dekatherms
EBITDA	Earnings before interest, taxes, depreciation and amortization, a non-GAAP measurement
ECA	Energy Cost Adjustment -- adjustments that allow us to pass the prudently-incurred cost of fuel and purchased energy through to customers.
Economy Energy	Electricity purchased by one utility from another utility to take the place of electricity that would have cost more to produce on the utility's own system
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 formerly wholly-owned subsidiary of Black Hills Non-regulated Holdings, which is presented in discontinued operations throughout this Annual Report filed on Form 10-K
EPA	United States Environmental Protection Agency
EPA Region VIII	EPA Region VIII (Mountains and Plains) located in Denver serving Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming and 27 Tribal Nations
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 RNSs 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 (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
IPP	Independent power producer
IPP Transaction	The July 11, 2008 sale of seven of our IPP plants
IRS	United States Internal Revenue Service
IUB	Iowa Utilities Board
JPB	Consolidated Wyoming Municipalities Electric Power System Joint Powers Board. The JPB exists for the purpose of, among other things, financing the electrical system of the City of Gillette.
KCC	Kansas Corporation Commission
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
kV	Kilovolt
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Loveland Area Project	Part of the Western Area Power Association transmission system
MACT	Maximum Achievable Control Technology
MAPP	Mid-Continent Area Power Pool
MATS	Utility Mercury and Air Toxics Rules under the United States EPA National Emissions Standards for Hazardous Air Pollutants from Coal and Oil Fired Electric Utility Steam Generating Units
Mbbl	Thousand barrels of oil
Mcf	Thousand cubic feet
Mcfe	Thousand cubic feet equivalent
MDU	Montana Dakota Utilities Co., a regulated utility division of MDU Resources Group, Inc.
MEAN	Municipal Energy Agency of Nebraska
MGP	Manufactured Gas Plants

MGTC	MGTC, Inc., a gas utility in northeast Wyoming serving 400 customers. MGTC is an acquisition we closed on January 1, 2015.
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMcfe	Million cubic feet equivalent
Moody’s	Moody’s Investors Service, Inc.

MSHA	Mine Safety and Health Administration
MTPSC	Montana Public Service Commission
MW	Megawatts
MWh	Megawatt-hours
N/A	Not Applicable
Native load	Energy required to serve customers within our service territory
Nebraska Gas	Black Hills Nebraska Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
NERC	North American Electric Reliability Corporation
NGL	Natural Gas Liquids (1 barrel equals 6 Mcfe)
NOAA	National Oceanic and Atmospheric Administration
NOAA Climate Normals	This dataset is produced once every 10 years. This dataset contains daily and monthly normals of temperature, precipitation, snowfall, heating and cooling degree days, frost/freeze dates, and growing degree days calculated from observations at approximately 9,800 stations operated by NOAA's National Weather Service.
NO_x	Nitrogen oxide
NOL	Net operating loss
NOPA	Notice of Proposed Adjustment
NPDES	National Pollutant Discharge Elimination System
NPSC	Nebraska Public Service Commission
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
OSHA	Occupational Safety & Health Administration
OTC	Over-the-counter
PCA	Power Cost Adjustment
PCCA	Power Capacity Cost Adjustment
Peak View Wind Project	New $109 million 60 MW wind generating project for Colorado Electric, 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
Recourse Leverage Ratio	Any indebtedness outstanding at such time, divided by Capital at such time. Capital being consolidated net-worth plus all recourse indebtedness.
RICE	Reciprocating Internal Combustion Engines
REPA	Renewable Energy Purchase Agreement
Revolving Credit Facility	Our $500 million credit facility used to fund working capital needs, letters of credit and other corporate purposes, which matures in 2019
RMSA	Retirement Medical Savings Account
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
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)
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 Holdings, LLC
Spinning Reserve	Generation capacity that is on-line but unloaded and that can respond within 10 minutes to compensate for generation or transmission outages
System Peak Demand	Represents the highest point of customer usage for a single hour for the system in total. Our system peaks include demand loads for 100% of plants regardless of joint ownership.
TCA	Transmission Cost Adjustment -- adjustments passed through to the customer based on transmission costs that are higher or lower than the costs approved in the rate case.
TCIR	Total Case Incident Rate (average number of work-related injuries incurred by 100 workers during a one-year period)
TIPA	Tax Increase Prevention Act of 2014
VEBA	Voluntary Employee Benefit Association
VOC	Volatile Organic Compound
WDEQ	Wyoming Department of Environmental Quality
WECC	Western Electricity Coordinating Council
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings

Website Access to Reports

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

Forward-Looking Information

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

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

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

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

History and Organization

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

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

Business Group	Financial Segment
Utilities	Electric Utilities
	Gas Utilities
Non-regulated Energy	Power Generation

Coal Mining
Oil and Gas

Our Electric Utilities segment generates, transmits and distributes electricity to approximately 207,200 electric customers in South Dakota, Wyoming, Colorado and Montana and also distributes natural gas to approximately 44,200 gas utility customers of Cheyenne Light in and around Cheyenne, Wyoming. Our Gas Utilities segment serves approximately 547,300 natural gas utility customers in Colorado, Nebraska, Iowa and Kansas. Our Electric Utilities own 841 MW of generation and 8,703 miles of electric transmission and distribution lines, and our Gas Utilities own 645 miles of intrastate gas transmission pipelines and 19,494 miles of gas distribution mains and service lines. Our Utilities Group generated net income of $117 million for the year ended December 31, 2015, and had total assets of $3.7 billion at December 31, 2015.

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 Coal Mining segment produces coal at our coal mine near Gillette, Wyoming, and sells the coal primarily under long-term contracts to mine-mouth electric generation facilities including our own regulated and non-regulated generating plants. Our Oil and Gas segment engages in the exploration, development and production of crude oil and natural gas, primarily in the Rocky Mountain region. In 2015, we began transitioning the Oil and Gas business to support utilities through a Cost of Service Gas Program. See the Key Elements of our Business Strategy in Item 7. Our Non-regulated Energy Group generated net income (loss) of $(135) million for the year ended December 31, 2015, and had total assets of $0.3 billion at December 31, 2015.

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. SourceGas 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. The combined company will serve approximately 1.2 million customers in eight states. Financial results for the SourceGas utilities will be reported under our Gas Utilities segment. For additional information on this acquisition, see the Key Elements of our Business Strategy in Item 7 and Note 2 - SourceGas Acquisition in the Notes to Consolidated Financial Statements in Item 8.

Segment reporting transition of Cheyenne Light’s Natural Gas distribution

Through December 31, 2015, Cheyenne Light’s natural gas operations have been included in our Electric Utilities Segment as these natural gas operations were consolidated within Cheyenne Light since its acquisition. Effective January 1, 2016, the natural gas operations of Cheyenne Light will be reported under our Gas Utilities Segment. 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 will be led by the Group Vice President, Natural Gas Utilities. Likewise, all regulated electric utility operations will be reported in our Electric Utilities Segment, which will be led by the Group Vice President, Electric Utilities.

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

Discontinued Operations in the accompanying financial information includes the results of our Energy Marketing segment sold in February 2012. The buyer asserted certain purchase price adjustments, some that we accepted, and several that we disputed. The disputed claims were substantially resolved through a binding arbitration decision dated January 17, 2014. We expensed an additional $1.1 million in 2013 related to the claims assigned to arbitration from purchase price adjustments we accepted through a partial settlement agreement with the buyer. Results for 2013 include the resolution of all previously unresolved purchase price adjustments.

Business Group Overview

Utilities Group

We conduct electric utility operations and combination electric and gas utility operations through three subsidiaries: Black Hills Power (South Dakota, Wyoming and Montana), Cheyenne Light (Wyoming), and Colorado Electric (Colorado). Our Electric Utilities generate, transmit and distribute electricity to approximately 207,200 customers; and also distribute natural gas to approximately 44,200 natural gas utility customers of Cheyenne Light in and around Cheyenne, Wyoming. Our electric generating facilities and power purchase agreements provide for the supply of electricity principally to our own distribution systems. Additionally, we sell excess power to other utilities and marketing companies, including our affiliates.

We conduct natural gas utility operations through our Colorado Gas, Nebraska Gas, Iowa Gas and Kansas Gas subsidiaries. Our Gas Utilities distribute and transport natural gas through our distribution network to approximately 547,300 customers. Additionally, we sell temporarily-available, contractual pipeline capacity and gas commodities to other utilities and marketing companies, including our affiliates.

We also provide non-regulated services through our Service Guard and Tech Services product lines. Service Guard primarily provides appliance repair services to approximately 64,000 residential customers through company technicians and third party service providers, typically through on-going monthly service agreements. Tech Services primarily serves gas transportation customers throughout our service territory by constructing customer-owned gas infrastructure facilities, typically through one-time contracts, with a limited number of on-going monthly maintenance agreements. Tech Services also provides electrical system construction services to large industrial customers of our electric utilities.

Electric Utilities Segment

Capacity and Demand

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

	System Peak Demand (in MW)					
	2015		2014		2013	
	Summer	Winter	Summer	Winter	Summer	Winter
Black Hills Power	424	369	410	389	422	403
Cheyenne Light [(a)]	212	202	198	197	185	192
Colorado Electric	392	303	384	298	381	280
Total Electric Utilities Peak Demands	1,028	874	992	884	988	875

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

Regulated Power Plants

As of December 31, 2015, our Electric Utilities' ownership interests in electric generation plants were as follows:

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

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

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

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

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

The 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)	2015	2014	2013
Coal	$10.89	$10.92	$10.89
Natural Gas	$51.14	$77.31	$53.53
Diesel Oil	$303.16	$174.04	$233.47
Total Average Fuel Cost	$14.62	$14.82	$14.65
Purchased Power - Coal, Gas and Oil	$47.81	$35.21	$29.95
Purchased Power - Renewable Sources	$50.92	$50.27	$49.20

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	2015	2014	2013
Coal	33 %	34 %	36 %
Gas, Oil and Wind	4	4	4
Total Generated	37	38	40
Purchased (1)	63	62	60
Total	100 %	100 %	100 %

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(1) Wind represents approximately 5% of our purchased power for 2015, 2014 and 2013.

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

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

- Colorado Electric's PPA with Black Hills Colorado IPP expiring on December 31, 2031, which provides 200 MW of energy and capacity to Colorado Electric from Black Hills Colorado IPP's combined-cycle turbines. This PPA is 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 Cargill expiring on December 31, 2016, which provides for the purchase of 50 MW of energy during heavy load timing intervals;

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

- Cheyenne Light's PPA with Black Hills Wyoming expiring on December 31, 2022, whereby Black Hills Wyoming provides 60 MW of unit-contingent capacity and energy from its Wygen I facility. The PPA includes an option for Cheyenne Light to purchase Black Hills Wyoming's ownership interest in the Wygen I facility through 2019 and would be 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);

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

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

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

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

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

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

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

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

2016-2017	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, 2015, our Electric Utilities owned the electric transmission and distribution lines shown below:

Utility	State	Transmission (in Line Miles)	Distribution (in Line Miles)
Black Hills Power	South Dakota, Wyoming	1,179	2,485
Black Hills Power - Jointly Owned (1)	South Dakota, Wyoming	44	—
Cheyenne Light	South Dakota, Wyoming	44	1,269
Colorado Electric	Colorado	585	3,097

(1) Black Hills Power owns 35% of a DC transmission tie that interconnects the Western and Eastern transmission grids, which are independently-operated transmission grids serving the western United States and eastern United States, respectively. This transmission tie, which is 65% owned by Basin Electric, provides transmission access to both the WECC region in the West and the MAPP region in the East. The transfer capacity of the tie is 200 MW from West to East, and 200 MW from East to West. Black Hills Power's electric system is located in the WECC

region. This transmission tie allows us to buy and sell energy in the Eastern grid without having to isolate and physically reconnect load or generation between the two transmission grids, thus enhancing the reliability of our system. It accommodates scheduling transactions in both directions simultaneously, provides additional opportunities to sell excess generation or to make economic purchases to serve our native load and contract obligations, and enables us to take advantage of power price differentials between the two grids.

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

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

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

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

- Shared Services Agreements -

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

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

Black Hills Power and Cheyenne Light receive certain staffing and management services from BHSC for Cheyenne Prairie.

- Jointly Owned Facilities -

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

Colorado Electric and AltaGas are parties to a shared joint ownership agreement whereby Colorado Electric charges AltaGas for operations and maintenance for their share of the Busch Ranch Wind Farm.

Operating Statistics

The following tables summarize information for our Electric Utilities:

Degree Days	2015			2014			2013	
	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:								
Black Hills Power	6,521	(12)%	(8)%	7,373	(3)%	4%	7,582	9%
Cheyenne Light	6,404	(10)%	(10)%	7,100	(4)%	—%	7,386	4%
Colorado Electric	4,846	(12)%	(12)%	5,534	(4)%	—%	5,740	1%
Combined (a)	5,729	(11)%	(10)%	6,473	(3)%	2%	6,691	5%
Cooling Degree Days:								
Black Hills Power	577	20%	(14)%	481	(34)%	(28)%	724	8%
Cheyenne Light	407	21%	16%	336	(35)%	(5)%	520	48%

Colorado Electric	1,270	38%	32%	919	(25)%	(4)%	1,230	28%
Combined [(a)]	861	32%	16%	654	(29)%	(12)%	918	7%

(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)	2015	2014	2013
Residential:			
Black Hills Power	$72,659	$69,712	$64,566
Cheyenne Light	39,587	36,634	35,778
Colorado Electric	97,418	94,391	95,631
Total Residential	209,664	200,737	195,975
Commercial:			
Black Hills Power	100,511	91,882	80,289
Cheyenne Light	64,207	59,758	57,444
Colorado Electric	93,821	90,909	87,732
Total Commercial	258,539	242,549	225,465
Industrial:			
Black Hills Power	33,336	28,451	27,705
Cheyenne Light	36,594	29,066	20,803
Colorado Electric	42,325	39,219	38,037
Total Industrial	112,255	96,736	86,545
Municipal:			
Black Hills Power	3,626	3,409	3,421
Cheyenne Light	2,179	1,930	1,918
Colorado Electric	12,058	13,312	13,106
Total Municipal	17,863	18,651	18,445
Subtotal Retail Revenue - Electric	598,321	558,673	526,430
Contract Wholesale:			
Total Contract Wholesale - Black Hills Power	17,537	21,206	21,956
Off-system/Power Marketing Wholesale:			
Black Hills Power	23,241	28,002	29,580
Cheyenne Light	5,215	8,179	8,712
Colorado Electric	1,270	5,726	8,329
Total Off-system/Power Marketing Wholesale	29,726	41,907	46,621
Other Revenue: [(a)]			
Black Hills Power	26,954	25,826	26,510
Cheyenne Light	2,374	2,253	1,916
Colorado Electric [(b)]	4,931	7,691	4,612
Total Other Revenue	34,259	35,770	33,038
Total Revenue - Electric	$679,843	$657,556	$628,045

(a) Other revenue primarily consists of transmission revenue.

(b) Results for 2014 include $1.8 million in technical service revenues for facility improvements at one of our large industrial customers.

Quantities Generated and Purchased (MWh)	2015	2014	2013
Generated:			
Coal-fired:			
Black Hills Power [(a)]	1,537,744	1,591,061	1,768,483
Cheyenne Light	690,633	697,220	688,318
Total Coal - fired	2,228,377	2,288,281	2,456,801
Natural Gas and Oil:			
Black Hills Power [(b)]	80,944	44,984	33,374
Cheyenne Light [(b)]	48,644	12,534	—
Colorado Electric [(c)]	100,732	140,942	247,758
Total Natural Gas and Oil	230,320	198,460	281,132
Wind:			
Colorado Electric	41,043	48,318	45,765
Total Wind	41,043	48,318	45,765
Total Generated:			
Black Hills Power	1,618,688	1,636,045	1,801,857
Cheyenne Light	739,277	709,754	688,318
Colorado Electric	141,775	189,260	293,523
Total Generated	2,499,740	2,535,059	2,783,698
Purchased:			
Black Hills Power	1,422,015	1,446,630	1,441,286
Cheyenne Light	791,351	766,475	779,677
Colorado Electric	1,952,625	1,898,232	1,886,627
Total Purchased [(d)]	4,165,991	4,111,337	4,107,590
Total Generated and Purchased	6,665,731	6,646,396	6,891,288

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(a) Neil Simpson I was retired on March 21, 2014.

(b) Cheyenne Prairie was placed into commercial service on October 1, 2014.

(c) Decreases in 2015 and 2014 generation primarily due to changes in commodity prices that impacted power marketing sales.

(d) Includes wind power of 227,396 MWh, 224,229 MWh and 222,069 MWh in 2015, 2014 and 2013, respectively.

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Quantities (MWh)	2015	2014	2013
Residential:			
Black Hills Power	521,828	542,008	555,204
Cheyenne Light	256,964	261,038	272,490
Colorado Electric	621,109	598,872	619,857
Total Residential	1,399,901	1,401,918	1,447,551
Commercial:			
Black Hills Power	792,466	782,238	730,701
Cheyenne Light	532,218	528,689	544,636
Colorado Electric	706,872	685,094	703,604
Total Commercial	2,031,556	1,996,021	1,978,941
Industrial:			
Black Hills Power	429,140	399,648	404,009
Cheyenne Light	498,141	382,306	281,727
Colorado Electric	472,360	432,167	371,102
Total Industrial	1,399,641	1,214,121	1,056,838
Municipal:			
Black Hills Power	31,924	32,076	34,344
Cheyenne Light	9,714	9,425	9,848
Colorado Electric	117,858	122,247	114,732
Total Municipal	159,496	163,748	158,924
Subtotal Retail Quantity Sold	4,990,594	4,775,808	4,642,254
Contract Wholesale:			
Total Contract Wholesale - Black Hills Power [(a)]	260,893	340,871	357,193
Off-system Wholesale:			
Black Hills Power	837,120	808,257	1,002,847
Cheyenne Light	121,659	191,069	234,566
Colorado Electric	41,306	119,315	219,349
Total Off-system Wholesale	1,000,085	1,118,641	1,456,762
Total Quantity Sold:			
Black Hills Power	2,873,371	2,905,098	3,084,298
Cheyenne Light	1,418,696	1,372,527	1,343,267
Colorado Electric	1,959,505	1,957,695	2,028,644
Total Quantity Sold	6,251,572	6,235,320	6,456,209
Other Uses, Losses or Generation, net [(b)]:			
Black Hills Power	167,332	177,577	158,845
Cheyenne Light	111,932	103,702	124,728
Colorado Electric	134,895	129,797	151,506
Total Other Uses, Losses and Generation, net	414,159	411,076	435,079
Total Energy	6,665,731	6,646,396	6,891,288

(a) Decrease in 2015 is primarily from the expiration in March 2015 of a 5 MW unit contingent capacity contract we had with MEAN.

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

Customers at End of Year	2015	2014	2013
Residential:			
Black Hills Power	57,178	56,511	55,840
Cheyenne Light	36,438	36,253	35,780
Colorado Electric	83,285	82,710	82,371
Total Residential	176,901	175,474	173,991
Commercial:			
Black Hills Power [a]	13,197	13,173	12,888
Cheyenne Light	4,760	4,489	4,471
Colorado Electric	11,215	11,156	11,060
Total Commercial	29,172	28,818	28,419
Industrial:			
Black Hills Power [a]	20	23	46
Cheyenne Light	4	4	3
Colorado Electric	63	66	61
Total Industrial	87	93	110
Other Electric Customers:			
Black Hills Power	335	325	310
Cheyenne Light	220	224	232
Colorado Electric	469	469	469
Total Other Electric Customers	1,024	1,018	1,011
Subtotal Retail Customers	207,184	205,403	203,531
Contract Wholesale:			
Total Contract Wholesale - Black Hills Power	3	3	3
Total Customers:			
Black Hills Power	70,733	70,035	69,087
Cheyenne Light	41,422	40,970	40,486
Colorado Electric	95,032	94,401	93,961
Total Electric Customers at End of Year	207,187	205,406	203,534

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

Cheyenne Light Natural Gas Distribution

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

	2015	2014	2013
Revenue - Gas (in thousands):			
Residential	$23,554	$24,426	$23,047
Commercial	12,916	11,279	10,326
Industrial	4,106	2,945	3,050
Other Sales Revenue	3,585	1,104	840
Total Revenue - Gas	$44,161	$39,754	$37,263
Gross Margin - Gas (in thousands):			
Residential	$13,011	$11,615	$12,706
Commercial	4,678	3,582	3,993
Industrial	733	525	598
Other Gross Margin	3,585	1,104	881
Total Gross Margin - Gas	$22,007	$16,826	$18,178
Quantities Sold (Dth):			
Residential	2,583,049	2,515,243	2,728,797
Commercial	2,073,213	1,482,904	1,653,021
Industrial	845,774	539,848	652,539
Total Quantities Sold [(a)]	5,502,036	4,537,995	5,034,357
Gas Customers at Year-End [(a)]	44,154	36,033	35,494

(a) Increase primarily represents the customer additions from Cheyenne Light's 2015 system acquisitions of Energy West and MGTC.

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Gas Utilities Segment

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

System Infrastructure (in line miles) as of December 31, 2015	Intrastate Gas Transmission Pipelines	Gas Distribution Mains	Gas Distribution Service Lines
Colorado	128	3,064	968
Nebraska	44	3,504	2,494
Iowa	180	2,719	2,624
Kansas	293	2,801	1,320
Total	645	12,088	7,406

Degree Days

	2015			2014			2013	
	Actual	Variance From Prior Year	Variance From 30-Year Average [c]	Actual	Variance From Prior Year	Variance From 30-Year Average [c]	Actual	Variance From 30-Year Average [c]
Heating Degree Days:								
Colorado	5,527	(10)%	(12)%	6,108	(3)%	(3)%	6,310	1%
Nebraska	5,350	(14)%	(12)%	6,193	(5)%	2%	6,516	8%
Iowa	6,629	(16)%	(2)%	7,875	2%	16%	7,743	14%
Kansas [a]	4,432	(13)%	(9)%	5,099	(4)%	4%	5,294	8%
Combined [b]	5,838	(14)%	(8)%	6,780	(2)%	7%	6,922	9%

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

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

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

Operating Statistics			
Revenue (in thousands)	2015	2014	2013
Residential:			
Colorado	$55,216	$58,439	$53,296
Nebraska	111,090	135,052	122,197
Iowa	90,865	124,145	98,498
Kansas	61,420	74,128	67,501
Total Residential	318,591	391,764	341,492
Commercial:			
Colorado	10,744	12,233	10,515
Nebraska	32,798	39,947	37,190
Iowa	39,314	60,640	47,494
Kansas	21,802	24,966	21,440
Total Commercial	104,658	137,786	116,639
Industrial:			
Colorado	1,433	1,909	1,661
Nebraska	1,339	830	900
Iowa	2,633	4,386	3,436
Kansas	12,887	16,963	15,753
Total Industrial	18,292	24,088	21,750
Other:			
Colorado	464	118	(17)
Nebraska	2,271	2,440	2,265
Iowa	580	724	543
Kansas	4,475	2,836	2,326
Total Other	7,790	6,118	5,117
Distribution:			
Colorado	67,857	72,699	65,455
Nebraska	147,498	178,269	162,552
Iowa	133,392	189,895	149,971
Kansas	100,584	118,893	107,020
Total Distribution	449,331	559,756	484,998
Transportation:			
Colorado	1,037	968	1,033
Nebraska	13,427	14,272	12,943
Iowa	4,762	4,934	4,809
Kansas	7,280	7,448	6,472
Total Transportation	26,506	27,622	25,257
Total Regulated Revenue	475,837	587,378	510,255
Non-regulated Services	31,302	30,390	29,434
Total Revenue	$507,139	$617,768	$539,689

Gross Margin (in thousands)	2015	2014	2013
Residential:			
Colorado	$18,153	$18,100	$18,244
Nebraska	51,168	54,996	53,367
Iowa	41,638	44,134	42,961
Kansas	31,789	32,809	32,111
Total Residential	142,748	150,039	146,683
Commercial:			
Colorado	2,921	3,048	3,009
Nebraska	10,822	11,708	11,560
Iowa	11,662	13,206	13,060
Kansas	8,409	8,115	7,436
Total Commercial	33,814	36,077	35,065
Industrial:			
Colorado	395	464	519
Nebraska	393	239	250
Iowa	253	294	321
Kansas	2,529	2,336	2,220
Total Industrial	3,570	3,333	3,310
Other:			
Colorado	464	118	(17)
Nebraska	2,271	2,441	2,266
Iowa	580	724	543
Kansas	4,405	1,990	1,723
Total Other	7,720	5,273	4,515
Distribution:			
Colorado	21,933	21,730	21,755
Nebraska	64,654	69,384	67,443
Iowa	54,133	58,358	56,885
Kansas	47,132	45,250	43,490
Total Distribution	187,852	194,722	189,573
Transportation:			
Colorado	1,037	968	1,033
Nebraska	13,427	14,272	12,943
Iowa	4,762	4,934	4,809
Kansas	7,280	7,448	6,472
Total Transportation	26,506	27,622	25,257
Total Regulated Gross Margin:			
Colorado	22,970	22,698	22,788
Nebraska	78,081	83,656	80,386
Iowa	58,895	63,292	61,694
Kansas	54,412	52,698	49,962
Total Regulated Gross Margin	214,358	222,344	214,830

Non-regulated Services	15,290	14,572	14,396
Total Gross Margin	$229,648	$236,916	$229,226

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Distribution Quantities Sold and Transportation (in Dth)	2015	2014	2013
Residential:			
Colorado	6,575,261	6,718,508	6,969,741
Nebraska	10,751,376	13,068,132	12,717,565
Iowa	9,648,973	12,172,281	11,359,220
Kansas	6,091,041	7,313,273	7,174,085
Total Residential	33,066,651	39,272,194	38,220,611
Commercial:			
Colorado	1,404,624	1,537,704	1,506,227
Nebraska	4,026,689	4,644,645	4,770,370
Iowa	5,492,230	7,182,173	7,056,978
Kansas	2,768,486	3,043,685	2,867,696
Total Commercial	13,692,029	16,408,207	16,201,271
Industrial:			
Colorado	288,212	354,630	405,047
Nebraska	246,184	122,662	150,227
Iowa	481,760	630,912	648,173
Kansas	3,346,525	3,384,797	3,355,930
Total Industrial	4,362,681	4,493,001	4,559,377
Wholesale and Other:			
Kansas	14,902	150,014	116,234
Total Wholesale and Other	14,902	150,014	116,234
Distribution Quantities Sold:			
Colorado	8,268,097	8,610,842	8,881,015
Nebraska	15,024,249	17,835,439	17,638,162
Iowa	15,622,963	19,985,366	19,064,371
Kansas	12,220,954	13,891,769	13,513,945
Total Distribution Quantities Sold	51,136,263	60,323,416	59,097,493
Transportation:			
Colorado	1,019,933	950,819	1,015,791
Nebraska	28,968,737	30,669,764	28,171,610
Iowa	19,867,265	19,959,462	20,176,525
Kansas	15,865,783	15,883,098	14,457,620
Total Transportation	65,721,718	67,463,143	63,821,546
Total Distribution Quantities Sold and Transportation:			
Colorado	9,288,030	9,561,661	9,896,806
Nebraska	43,992,986	48,505,203	45,809,772
Iowa	35,490,228	39,944,828	39,240,896
Kansas	28,086,737	29,774,867	27,971,565
Total Distribution Quantities Sold and Transportation	116,857,981	127,786,559	122,919,039

Customers at End of Year	2015	2014	2013
Residential:			
Colorado	74,345	72,360	70,410
Nebraska	180,897	180,014	178,389
Iowa	139,205	138,503	137,525
Kansas	99,013	99,359	99,315
Total Residential	493,460	490,236	485,639
Commercial:			
Colorado	3,825	3,788	3,737
Nebraska	15,948	15,900	15,739
Iowa	15,433	15,303	15,418
Kansas	10,813	10,547	9,832
Total Commercial	46,019	45,538	44,726
Industrial:			
Colorado	224	205	207
Nebraska	145	147	136
Iowa	98	90	94
Kansas	1,377	1,277	1,358
Total Industrial	1,844	1,719	1,795
Transportation:			
Colorado	40	34	36
Nebraska	4,271	4,151	4,240
Iowa	460	418	421
Kansas	1,161	1,145	1,171
Total Transportation	5,932	5,748	5,868
Wholesale:			
Kansas [a]	—	8	7
Total Wholesale	—	8	7
Total Customers:			
Colorado	78,434	76,387	74,390
Nebraska	201,261	200,212	198,504
Iowa	155,196	154,314	153,458
Kansas	112,364	112,336	111,683
Total Customers at End of Year	547,255	543,249	538,035

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

Utilities Group Business Characteristics

Seasonal Variations of Business

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

Competition

We generally have limited competition for the retail distribution of electricity and natural gas in our service areas. Various restructuring and competitive initiatives have been discussed in several of the states in which our utilities operate. These initiatives would be aimed at increasing competition or providing for distributed generation. To date, these initiatives have had no 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 Utilities Group operates:

Subsidiary	Jurisdic-tion	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Tariff and Rate Matters	Percentage of Power Marketing Activity Shared with Customers
Electric Utilities:								
Black Hills Power	WY	9.9%	8.13%	46.7%/53.3%	$46.8	10/2014	ECA	65%
	SD	Global Settlement	7.76%	Global Settlement	$543.9	10/2014	ECA, TCA, Energy Efficiency Cost Recovery/DSM, Vegetation Management	70%
	SD		8.16%			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
Cheyenne Light - Electric	WY	9.9%	7.98%	46%/54%	$376.8	10/2014	PCA, Energy Efficiency Cost Recovery/DSM, Rate Base Recovery on Acquisition Adjustment	N/A
	FERC	10.6%	8.51%	46%/54%	$31.5	5/2014	FERC Transmission Tariff	N/A
Cheyenne Light - Gas	WY	9.9%	7.98%	46%/54%	$59.6	10/2014	GCA, Energy Efficiency Cost Recovery/DSM, Rate Base Recovery on Acquisition Adjustment	N/A
Colorado Electric	CO	9.83%	7.55%	50.2%/49.8%	$448.3	1/2015	ECA, TCA, PCCA, Energy Efficiency Cost Recovery/DSM, Renewable Energy Standard Adjustment, Construction Rider	90%
Gas Utilities:								
Colorado Gas	CO	9.6%	8.41%	50%/50%	$64.0	12/2012	GCA, Energy Efficiency Cost Recovery/DSM	N/A
Nebraska Gas	NE	10.1%	9.11%	48%/52%	$161.0	9/2010	GCA, Cost of Bad Debt Collected through GCA, Infrastructure System Replacement Cost Recovery Surcharge	N/A
	KS				$127.4	1/2015		N/A

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

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

Some of the mechanisms we have in place include the following by utility and state:

In South Dakota, Black Hills Power has:

- An annual adjustment clause which provides for the direct recovery of increased fuel and purchased power cost incurred to serve South Dakota customers. Additionally, the ECA contains an off-system sales sharing mechanism in which South Dakota customers will receive a credit equal to 70% of off-system power marketing operating income. The ECA allows methodology to directly assign renewable resources and firm purchases to the customer load. In Wyoming, a similar fuel and purchased power cost adjustment is also in place.

- 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 Black Hills Power's open access transmission tariff.

In Wyoming, Cheyenne Light has:

- An annual cost adjustment mechanism that allows us to pass the prudently-incurred costs of fuel and purchased power through to electric customers. 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 Cheyenne Light'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. Additionally, Colorado allows an annual TCA rider that includes nine months of actual transmission investment and three months of forecasted investment, with an annual true-up mechanism.

- Effective January 1, 2015, a rider to recover a return on the construction costs of a $65 million natural gas-fired combustion turbine that will replace the retired W.N. Clark power plant.

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

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

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

- In Iowa, we have a Capital Infrastructure Automatic Adjustment Mechanism that allows for recovery of certain capital infrastructure investments.
- In Nebraska, we have an Infrastructure System Replacement Cost mechanism that allows for recovery of certain capital infrastructure investments.

Rates and Rate Activity

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

	Type of Service	Date Requested	Effective Date	Revenue Amount Requested	Revenue Amount Approved
Kansas Gas [(a)]	Gas	4/2014	1/2015	$7.3	$5.2
Colorado Electric [(b)]	Electric	4/2014	1/2015	$4.0	$3.1
Black Hills Power [(c)]	Electric	3/2014	10/2014	$14.6	$6.9
Iowa Gas [(d)]	Gas	3/2015	6/2015	$0.9	$0.9
Nebraska Gas [(e)]	Gas	4/2015	8/2015	$1.5	$1.5

(a) 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.

(b) 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 also allows Colorado Electric to recover a return on the construction costs for a $65 million natural gas-fired combustion turbine that will replace the retired W.N. Clark power plant.

(c) On March 2, 2015, the SDPUC issued an order approving a rate stipulation and agreement authorizing an increase for Black Hills Power of $6.9 million in annual electric revenue. The agreement was a Global Settlement and did not stipulate return on equity and capital structure. The SDPUC's decision provides Black Hills Power a return on its investment in Cheyenne Prairie and associated infrastructure, and provides recovery of its share of operating expenses for this natural gas-fired facility. Black Hills Power 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.

(d) On March 17, 2015, Iowa Gas filed with the IUB for a capital investment recovery surcharge increase of $0.9 million. Iowa Gas received approval from the IUB on May 28, 2015.

(e) On April 6, 2015, Nebraska Gas filed with the NPSC for a capital investment recovery surcharge increase of $1.5 million. Nebraska Gas received approval from the NPSC on July 27, 2015.

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. If approved, our non-utility affiliate will 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 proposed Cost of Service Gas Program model has a capital structure of 60% equity and 40% debt, and seeks a utility-like return. Based on historical performance, the cost of production is expected to be more stable and predictable than the spot market price of natural gas.

We currently have hearing dates with the commissions in all six states. The scheduled hearing for Iowa is in March 2016, for Nebraska in April 2016, for Kansas and Wyoming in May 2016, for South Dakota in June 2016, and for Colorado in July 2016. The program is not necessarily dependent on approvals from all states, however, the total program volumes depend on the sum of volumes approved by the various state commissions. Our long-term target for the program is up to 50% (38 Bcf) of annual demand for our gas utilities and gas-fired electric generation.

Other State Regulations

Certain states where we conduct electric utility operations have adopted renewable energy portfolio standards that require or encourage our Electric Utilities to source, by a certain future date, a minimum percentage of the electricity delivered to customers from renewable energy generation facilities. At December 31, 2015, we were subject to the following renewable energy portfolio standards or objectives:

- Colorado. Colorado adopted a renewable energy standard that has two components: (i) electric resource standards and (ii) a 2% retail rate impact for compliance with the electric resource standards. The electric resource standards require our Colorado Electric subsidiary to generate, or cause to be generated, electricity from renewable energy sources equaling: (i) 20% of retail sales from 2015 to 2019; and (ii) 30% of retail sales by 2020. Of these amounts, 3% must be generated from distributed generation sources with one-half of these resources being located at customer facilities. The net annual incremental retail rate impact from these renewable resource acquisitions (as compared to non-renewable resources) is limited to 2%. The standard encourages the CPUC to consider earlier and timely cost recovery for utility investment in renewable resources, including the use of a forward rider mechanism. We are currently in compliance with these standards.

On 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. The project will be built by Invenergy Wind Development Colorado LLC and is expected to be completed in the fourth quarter of 2016. On September 24, 2015, Colorado Electric filed an uncontested Settlement Agreement that would approve the build transfer proposal. 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. The settlement requires Colorado Electric 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 for the first 10 years. The Commission determined it did not need to hold a hearing regarding the settlement and considered and approved the project on October 21, 2015. Pending final approvals and permits, Colorado Electric will purchase the project for approximately $109 million through progress payments throughout 2016, with ownership transfer occurring just before achieving commercial operation.

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

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

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

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

Federal Regulation

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

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

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

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

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

Environmental Matters

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

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

Environmental Expenditure Estimates	Total (in thousands)
2016	$2,300
2017	1,572
2018	2,589

Total	$6,461

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. 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.

Air Emissions

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

Clean Air Act

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

Title IV applies to several of our generation facilities, including the Neil Simpson II, Neil Simpson CT, Lange CT, Wygen II, Wygen III, Pueblo Airport Generating Station, Cheyenne Prairie and Wyodak plants. Without purchasing additional allowances, we currently hold sufficient allowances to satisfy Title IV at all such plants through 2045. For future plants, we plan to secure the requisite number of allowances by reducing SO_2 emissions through the use of low sulfur fuels, installation of “back end” control technology, use of banked allowances and if necessary, the purchase of allowances on the open market. We expect to integrate the cost of obtaining the required number of allowances needed for future projects into our overall financial analysis of such new projects.

Title V of the Clean Air Act requires that all of our generating facilities obtain operating permits. All of our existing facilities have received Title V permits, with the exception of Wygen III, Pueblo Airport Generating Station and Cheyenne Prairie Generating Station. Wygen III, Pueblo Airport Generating Station and Cheyenne Prairie Generating Station are allowed to operate under their construction permit until the Title V permit is issued by the state. The Title V application for Wygen III was submitted in January 2011, with the permit expected in 2016. The Pueblo Airport Generating Station Title V application was filed in September 2012, with the permit expected in 2016. The Cheyenne Prairie Generating Station Title V application was submitted in 2015. All applications were filed in accordance with regulatory requirements.

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

On February 16, 2012, the EPA published in the Federal Register the National Emission Standards for Hazardous Air Pollutants from Coal and Oil Fired Electric Utility Steam Generating Units (MATS), with an effective date of April 16, 2012. This rule imposes requirements for mercury, acid gases, metals and other pollutants. Affected units had a compliance deadline of April 16, 2015, with a pathway defined to apply for a one year extension due to certain limited circumstances. The current state air permits for Wygen II and Wygen III provide mercury emission limits and monitoring requirements with which we are in compliance. Neil Simpson II, Wygen II and Wygen III have been utilized for internal study and review of mercury emission control technology and have mercury monitors in place. Due to mercury absorbent issues encountered in 2015, the state of Wyoming approved a one year compliance deadline extension to April 16, 2016 for Neil Simpson II, Wygen II and Wygen III, for mercury only. The other components of the MATS rule remain in effect and these plants are in compliance with those requirements. The Wyodak plant is in compliance with all requirements of the MATS regulation.

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 2016 and, as proposed, will be applicable to the Pueblo Airport Generating Station, Cheyenne Prairie and eventually all the combustion turbines in our fleet. Among other things, the rule seeks to eliminate startup exemptions and clearly define overhauls for impact on the EPA's New Source Review regulations, with the intention of eventually bringing all units under the applicability of this rule. The primary impact is expected to be on our older existing units, which will eventually be required to meet tighter NO_x emission limitations.

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

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 NOx emission limits on new power generation units.

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

Regional Haze

In January 2011, the states of Wyoming and South Dakota submitted their plans to EPA Region VIII, identifying NO_x, SO_2 and particulate matter emission reductions intended to meet the Class I Areas (National Parks and Wilderness Areas) visibility improvement requirements under the EPA's Regional Haze Program. Although none of our South Dakota or Wyoming power plants were included in those plans, we anticipate that Neil Simpson II will eventually be included in required five year progress reports. The state of Wyoming is currently developing their initial progress report for submittal in the spring of 2016. Neil Simpson II is not currently a discussion item in that report.

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

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

The Wyodak Power Plant is included in EPA's January 30, 2014 Regional Haze Federal Implementation Plan, which includes significant additional NO_x controls by March 1, 2019. Our share of those costs is estimated at $20 million. The State of Wyoming and PacifiCorp filed requests for reconsideration and Administrative Stay with EPA and the United States Court of Appeals for the 10th Circuit. On September 9, 2014, the 10th Circuit stayed EPA's NO_x requirement for Wyodak pending outcome of the appeal, which is anticipated to be settled by the summer of 2016.

Greenhouse Gas Regulations

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

On June 3, 2010, the EPA promulgated the GHG Tailoring Rule, implementing regulations of GHG for permitting purposes. This rule will impact us in the event of a major modification at an existing facility or in the event we establish a new major source of GHG emissions, as defined by EPA regulations. Upon renewal of operating permits for existing permitted facilities, monitoring and reporting requirements will be implemented. This rule established the basis for EPA's October 23, 2015 suite of GHG emission rules for existing, new, modified and reconstructed facilities. 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 basis 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. States are required to develop and submit compliance plans to EPA, with the initial submittal due by September 2016. The rule allows for a two year extension to submit a final plan and the states we operate in have indicated they will be submitting the extension request. Also on October 23, 2015, EPA proposed a Federal Implementation Plan, which will be imposed on any state that fails to submit a plan or fails to include the required contents of the plan. That rule will contain the modeling standards for CPP compliance and will be an integral part of state plan development. On February 9, 2016, the U.S. Supreme Court entered an order staying the Clean Power Plan. The stay of the CPP will remain in place until the U.S. Supreme Court either denies a petition for certiorari following the U.S. Court of Appeals' decision on the substantive challenges to the CPP, if one is submitted, or until the U.S. Supreme Court enters judgment following grant of a petition for certiorari. 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. We do not expect a final judicial decision on challenges to the CPP earlier than mid-2017. While we cannot predict the terms of state plans, 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, we met with South Dakota, Wyoming and Colorado regulatory agencies to discuss the rule implementation and potential compliance pathways.

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

In 2015, we reported 2014 GHG emissions from our Power Generation and Gas Utilities in order to comply with the EPA's GHG Annual Inventory regulation, issued in 2009. We continue to report annual GHG emissions as required by the EPA. Climate change issues are the subject of a number of lawsuits, the outcome of which could impact the utility industry. We will continue to review GHG impacts as legislation or regulation develops and litigation is resolved.

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

Solid Waste Disposal

Various materials used at our facilities are subject to disposal regulations. Under state permits, we dispose of all solid wastes collected as a result of burning coal at our power plants in approved 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 that is currently underway, 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 that was near capacity. An application to close the impoundment was approved on April 13, 2012. Site closure work was completed and the state issued an approval of closure activities on October 21, 2014. Post-closure monitoring activities will continue for 30 years. In September 2013, Osage also received a permit to close the small industrial rubble landfill. Site work has been completed and the state issued an approval of closure activities on October 21, 2014. Post closure monitoring will continue for 30 years. As of August 31, 2012, we suspended operations at Ben French and the plant was permanently retired on March 21, 2014. The Ben French temporary ash holding area was closed in accordance with state guidelines, with the state issuing a closure certification on March 14, 2014.

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

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

Agreements are in place that 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 Power 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 Power, MDU and the City of Gillette each share the costs for solid waste from Wygen III according to their respective ownership interests.

Additional unexpected material costs could also result in the future if any regulatory agency determines that solid waste from the burning of coal contains a hazardous material that requires special treatment, including previously disposed solid waste. In that event, the regulatory authority could hold entities that dispose of such waste responsible for remedial treatment. On December 19, 2014, the EPA Administrator signed coal ash regulations designating coal ash as a solid waste. These regulations are not applicable to our operations as all our coal ash is used as mine backfill. However, it is expected that the U.S. Office of Surface Mining will develop similar regulations, anticipated to be proposed in early 2016.

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 $1.4 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). The successor is 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 over management of remaining groundwater contamination, the EPA has indicated they will be proposing to include the Norfolk site on the National Priority List. While we do not expect a financial impact from this action, we cannot be assured of that until the process has run its course. Nebraska Gas enrolled Blair and Plattsmouth in Nebraska’s Voluntary Cleanup Program. Site remediation was completed in September 2012. Both of these Nebraska sites were required to monitor groundwater quality for a minimum two-year period ending in 2015. We have not yet received state approval for “no further action”. 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.

As of December 31, 2015, we estimate a range of approximately $2.9 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. However, late in 2015 we were notified that the EPA would like to perform site assessments to determine current contamination levels. Depending on the results of the investigation, the priority for cleanup as well as communications with potential responsible parties may be elevated.

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

Non-regulated Energy Group

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

- Power Generation
- Coal Mining
- Oil and Gas

Power Generation Segment

Our Power Generation segment, which operates through Black Hills Electric Generation and its subsidiaries, acquires, develops and operates our non-regulated power plants. As of December 31, 2015, 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, 2015, 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] [b]	Gas	Pueblo, Colorado	100.0%	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.

(b) On February 12, 2016, Black Hills Electric Generation entered into a definitive agreement to sell a 49.9%, non-controlling interest in Black Hills Colorado IPP for $215 million to AIA Energy North America LLC, an infrastructure investment platform managed by Argo Infrastructure Partners. The sale is expected to close in April of 2016, pending receipt of regulatory approval from FERC. Black Hills Colorado IPP will continue to own and operate the facility.

Black Hills Wyoming - Wygen I. The Wygen I generation facility is a mine-mouth, coal-fired power plant with a total capacity of 90 MW located at our Gillette, Wyoming energy complex. We own 76.5% of the plant and MEAN owns the remaining 23.5%. We sell 60 MW of unit-contingent capacity and energy from this plant to Cheyenne Light under a PPA that expires on December 31, 2022. The PPA includes an option for Cheyenne Light to purchase Black Hills Wyoming's ownership interest in the Wygen I facility through 2019. The purchase price in the contract related to the option is $2.6 million per 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, 2015 was $74 million and if Cheyenne Light had exercised the purchase option at year-end 2015, the estimated purchase price would have been approximately $155 million and would be subject to WPSC and FERC approval in order to obtain regulatory treatment. Cheyenne Light has delayed consideration of exercising the purchase option pending the state of Wyoming finalizing their State Implementation Plans to comply with the EPA's Clean Power Plan. Wyoming has until June 30, 2016 to submit their final plans to the EPA. We sell excess power from our generating capacity into the wholesale power markets when it is available and economical.

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

The following table summarizes MWh for our Power Generation segment:

Quantities Sold, Generated and Purchased (MWh) [a]	2015	2014	2013
Sold			
Black Hills Colorado IPP	1,133,190	1,178,464	1,008,482
Black Hills Wyoming [b]	663,052	581,696	556,307
Total Sold	1,796,242	1,760,160	1,564,789
Generated			
Black Hills Colorado IPP	1,133,190	1,178,464	1,008,482
Black Hills Wyoming	561,930	543,796	556,106
Total Generated	1,695,120	1,722,260	1,564,588
Purchased			

Black Hills Wyoming [(b)]	68,744	38,237	5,481
Total Purchased	68,744	38,237	5,481

(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.

- Shared Services Agreements

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

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

Black Hills Colorado IPP, Cheyenne Light and Black Hills Power are parties to a Spare Turbine Use Agreement, whereby Black Hills Colorado IPP charges Black Hills Power and Cheyenne Light 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 also apply to our Power Generation operations. See the discussion above under the “Environmental” and “Regulation” captions for the Utilities Group for additional information on certain laws and regulations.

Clean Air Act. The Clean Air Act impacts our Power Generation business in a manner similar to the impact disclosed for our Electric Utilities. Our Wygen I and Pueblo Airport Generating facilities are subject to Titles IV and V of the Clean Air Act and have the required permits in place or have applications submitted in accordance with regulatory time lines. As a result of SO_2 allowances credited to us from the installation of sulfur removal equipment at our jointly owned Wyodak plant, we hold sufficient allowances for our Wygen I plant through 2045, without purchasing additional allowances. The EPA’s MACT rule described in the Utilities Group section will apply to Wygen I.

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

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

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

Coal Mining Segment

Our Coal Mining segment operates through our WRDC subsidiary. We surface mine, process and sell primarily low-sulfur sub-bituminous coal at our coal mine near Gillette, Wyoming. The WRDC coal mine, which we acquired in 1956 from Homestake Gold Mining Company, is located in the Powder River Basin. The Powder River Basin contains one of the largest coal reserves in the United States. We produced approximately 4.1 million tons of coal in 2015.

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, had in recent years trended upwards. The overburden ratio at December 31, 2015 was 1.5, which increased from the prior year as we continued mining in areas with higher overburden. We expect our stripping ratio to increase to approximately 1.9 by the end of 2016 as we mine back into areas with higher overburden.

Mining rights to the coal are based on four federal leases and one state lease. The federal leases expire between March 31, 2021 to October 31, 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, 2015, we estimated our recoverable coal reserves to be approximately 204 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 49 years at the current expected production levels. Our recoverable coal reserve estimates are periodically updated to reflect past coal production and other geological and mining data. Changes in mining methods or the utilization of new technologies may increase or decrease the recovery basis for a coal seam. Our recoverable coal reserves include reserves that can be economically and legally extracted at the time of their determination. We use various assumptions in preparing our estimate of recoverable coal reserves. See Risk Factors under Coal Mining for further details.

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

- Black Hills Power for use at its Neil Simpson II plant. This contract is for the life of the plant;
- Cheyenne Light for use at its 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 Black Hills Power. PacifiCorp is obligated to purchase a minimum of 1.5 million tons of coal each year of the contract term, subject to adjustments for planned outages. Black Hills Power 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 Black Hills Power, 25% by MDU and 23% by the City of Gillette to which we sell approximately 600,000 tons of coal each year. This contract expires June 1, 2060;

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

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

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

The price of unprocessed coal sold to PacifiCorp for the Wyodak plant is determined by the coal supply agreement described above. The agreement 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 Utilities Group also apply to our Coal Mining segment. Specifically, the EPA is examining plans to reduce methane emissions from coal mines as part of 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 will collaborate with the EPA and propose mine backfill regulations in early 2016. These regulations may increase the cost of ash disposal for the power plants and/or increase backfill costs for the coal mine.

Mine Reclamation. Reclamation is required during production and after mining has been completed. Under applicable law, we must submit applications to, and receive approval from, the WDEQ for any mining and reclamation plan that provides for orderly mining, reclamation and restoration of the WRDC mine. We have approved mining permits and are in compliance with other permitting programs administered by various regulatory agencies. The WRDC coal mine is permitted to operate under a five year mining permit issued by the State of Wyoming. The current permit expires in 2016 and the application for renewal was filed in 2015 per state requirements. Based on extensive reclamation studies, we have accrued approximately $19 million for reclamation costs as of December 31, 2015. 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. In 2015, we began transitioning our Oil and Gas business toward supporting our planned 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. In the current low energy commodity price environment, 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. Our oil and gas strategy for the last several years has 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. Drilling and completion costs have trended down as we focus on efficiencies and cost reductions. Sustained low oil and natural gas prices have also resulted in reduced costs for drilling and completion services, equipment and materials. We are currently assessing the Piceance wells to determine their potential fit for a Cost of Service Gas Program.

As of December 31, 2015, 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 55% of the facility’s throughput. We also own natural gas gathering, compression and treating facilities, and water collection and delivery systems serving the operated San Juan and Piceance Basin properties and working interests in similar facilities serving our Wyoming properties.

At December 31, 2015, we had total reserves of approximately 105 Bcfe, of which natural gas comprised 70%, crude oil comprised 20% and NGLs comprised 10%. The majority of our reserves are located in select crude oil and natural gas producing basins in the Rocky Mountain region. Approximately 18% of our reserves are located in the San Juan Basin of northwestern New Mexico, primarily in the East Blanco Field of Rio Arriba County; 25% are located in the Powder River Basin of Wyoming, primarily in the Finn-Shurley Field of Weston and Niobrara counties; and 50% 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, an independent consulting and engineering firm located in Fort Worth, Texas. Reserves were determined consistent with SEC requirements using a 12-month average product price calculated using the first-day-of-the-month price for each of the 12 months in the reporting period held constant for the life of the properties. Estimates of economically recoverable reserves and future net revenues are based on a number of variables, which may differ from actual results. Reserves for crude oil, natural gas, and NGLs are reported separately and then combined for a total MMcfe (where oil and NGLs in Mbbl are converted to an MMcfe basis by multiplying Mbbl by six).

The SEC definition of “reliable technology” allows the use of any reliable technology to establish reserve volumes in addition to those established by production and flow test data. This definition allows, but does not require us, to book PUD locations that are more than one location away from a producing well. We elected to only include PUDs which are one location away from a producing well in our volume reserve estimate. Companies are allowed, but not required, to disclose probable and possible reserves. We have elected not to report these additional reserve categories. Additional information on our oil and gas reserves, related financial data and the SEC requirements can be found in Note 21 to the Consolidated Financial Statements in this Annual Report on Form 10-K.

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

CG&A is a Texas Registered Engineering Firm. Our primary contact at CG&A is Mr. Zane Meekins. Mr. Meekins has been practicing consulting petroleum engineering since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas and has over 28 years of practical experience in petroleum engineering and over 26 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 29 years of experience as a petroleum engineer. He has over 22 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.

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

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

The following tables set forth summary information concerning our estimated proved developed and undeveloped reserves, by basin, as of December 31, 2015, 2014 and 2013:

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

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

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(a) Proved reserves presented for 2013 do not include NGLs.

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, 2015, 2014 and 2013:

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

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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

(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

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

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

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

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

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

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

Production Volumes

		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

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

Other Information

	As of December 31, 2015	As of December 31, 2014
Proved developed reserves as a percentage of total proved reserves on an MMcfe basis	100 %	88 %
Proved undeveloped reserves as a percentage of total proved reserves on an MMcfe basis [(a)]	— %	12 %
Present value of estimated future net revenues, before tax, discounted at 10% (in thousands)	$85,711	$188,704

(a) The decrease to proved undeveloped reserves is primarily due to our completion efforts in 2015 on our existing wells and our decision to limit additional drilling and exploration, driven by current year economic conditions. See Note 21 in the accompanying Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for further details.

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

	December 31, 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

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

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

Drilling Activity

In 2015, we participated in drilling 21 gross (11 net) development and exploratory wells, with a net well success rate of 81%. A development well is a well drilled within a proved area of a reservoir known to be productive. An exploratory well is a well drilled to find and/or produce oil or gas in an unproved area, to find a new reservoir in a previously productive field or to extend a known reservoir. Gross wells represent the total wells we participated in, regardless of our ownership interest, while net wells represent the sum of our fractional ownership interests within those wells.

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

Year ended December 31,	2015		2014		2013	
Net Development Wells	Productive	Dry	Productive	Dry	Productive	Dry
Piceance	—	—	—	—	—	—
San Juan	—	—	—	—	—	—
Williston	0.09	—	0.26	—	1.00	—
Powder River	1.00	—	—	—	0.19	—
Other	—	—	—	—	—	—
Total net development wells	1.09	—	0.26	—	1.19	—

Year ended December 31,	2015		2014		2013	
Net Exploratory Wells	Productive	Dry	Productive	Dry	Productive	Dry
Piceance	7.03	—	1.17	—	1.00	—
San Juan	—	—	—	—	—	—
Williston	—	—	—	—	—	—
Powder River	0.60	2.00	3.00	—	—	1.80
Other	—	—	—	—	0.80	—
Total net exploratory wells	7.63	2.00	4.17	—	1.80	1.80

As of December 31, 2015, we were participating in the drilling of 23 gross (4.12 net) wells, which had been commenced but not yet completed.

Recompletion Activity

Recompletion activities for the years ended December 31, 2015, 2014 and 2013 were insignificant to our overall oil and gas operations.

Productive Wells

The following table summarizes our gross and net productive wells at December 31, 2015, 2014 and 2013:

	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.

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

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

Acreage

The following table summarizes our undeveloped, developed and total acreage by location as of December 31, 2015:

	Undeveloped		Developed		Total	
	Gross	Net [(a)]	Gross	Net	Gross	Net
Piceance	92,500	68,391	36,797	30,660	129,297	99,051
San Juan	36,398	36,509	24,399	23,068	60,797	59,577
Williston	909	73	10,048	1,585	10,957	1,658
Powder River	170,474	98,387	41,964	17,272	212,438	115,659
Montana	26,864	18,003	480	60	27,344	18,063
Other	16,858	15,182	27,108	4,887	43,966	20,069
Total	344,003	236,545	140,796	77,532	484,799	314,077

(a) Approximately 15% (44,469 gross and 28,933 net acres), 5% (20,668 gross and 8,970 net acres) and 2% (14,229 gross and 4,642 net acres) of our undeveloped acreage could expire in 2016, 2017 and 2018, 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 now have excess production capacity from wells completed in 2015, and four additional wells which have not yet been completed, and 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 Bureau of Land Management, the Office of Natural Resources Revenue and the Bureau of Indian Affairs, along with each Native American tribe, promulgate and enforce regulations pertaining to crude oil and natural gas operations and administration of royalties on federal onshore and tribal lands. These regulations include such matters as lease provisions, drilling and production requirements, environmental standards and royalty considerations. Each Native American tribe is a sovereign nation possessing the power to enforce laws and regulations independent from federal, state and local statutes and regulations. These tribal laws and regulations include various taxes, fees and other conditions that apply to lessees, operators and contractors conducting operations on tribal lands. One or more of these factors may increase our cost of doing business on tribal lands and impact the expansion and viability of our gas, oil and gathering operations on such lands.

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

Environmental Regulations. Our operations are subject to various federal, state and local laws and regulations relating to the discharge of materials into, and the protection of, the environment. We must account for the cost of complying with environmental regulations in planning, designing, drilling, operating and abandoning wells. In most instances, the regulatory requirements relate to the handling and disposal of drilling and production waste products, water and air pollution control procedures (such as spill prevention, control and countermeasure plans, storm water pollution prevention plans, groundwater monitoring, state air quality permits and underground injection control disposal permits), chemical storage 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, and 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. State regulations were finalized in early 2014. New Mexico incorporated Quad O regulations, effective December 19, 2013. Wyoming incorporated Quad O regulations effective January 3, 2014.

Our policy is to meet or exceed all applicable local, state, tribal and federal regulatory requirements when drilling, casing, cementing, completing and producing 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 be submitted by March 31, 2017 to cover 2016 emissions. We are currently expanding our current 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 proposed rule, scheduled for finalization in 2016, also includes provisions for clarifying permitting requirements for determination of major/minor source status. The outcome of this proposal could create permitting delays if a final aggregation definition would require permitting our facilities as major sources. 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 2015, the Department of Interior's BLM was scheduled to propose rules for new and existing oil and gas wells on public lands, targeting reduction or elimination of venting, flaring and leaks of natural gas. That proposal has not yet been issued for public comment.

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 Pueblo, Colorado, we own a building of approximately 46,600 square feet used for a service center and approximately 25,700 square feet used for a warehouse.
- In Cheyenne, Wyoming, we own a business office with approximately 14,300 square feet and a service center and garage with an aggregate of approximately 29,000 square feet.
- In Papillion, Nebraska, we own an office building consisting of approximately 36,600 square feet.
- In Nebraska, Iowa, Colorado and Kansas we own various office, service center, storage, shop and warehouse space totaling over 283,100 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 156,300 square feet utilized by our Electric Utilities and our Coal Mining segments.

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

- Approximately 8,800 square feet for an operations and customer call center and 9,100 square feet of office space in Rapid City, South Dakota;
- Approximately 37,600 square feet for a customer call center in Lincoln, 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;
- Approximately 107,100 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 Black Hills Power and Cheyenne Light are subject to liens securing first mortgage bonds issued by Black Hills Power and Cheyenne Light, respectively.

Employees

At December 31, 2015, we had 2,003 full-time employees. Approximately 29% of our employees are represented by a collective bargaining agreement. We have not experienced any labor stoppages in recent years. At December 31, 2015, approximately 25% of our Utilities Group employees were eligible for regular or early retirement.

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

	Number of Employees
Corporate	419
Utilities	1,454
Non-regulated Energy	130
Total	2,003

At December 31, 2015, certain of our Utilities Group employees were covered by the following collective bargaining agreements:

Utility	Number of Employees	Union Affiliation	Expiration Date of Collective Bargaining Agreement
Black Hills Power	138	IBEW Local 1250	March 31, 2017
Cheyenne Light	44	IBEW Local 111	June 30, 2016
Colorado Electric	118	IBEW Local 667	April 15, 2018
Iowa Gas	119	IBEW Local 204	July 31, 2020
Kansas Gas	19	Communications Workers of America, AFL-CIO Local 6407	December 31, 2019
Nebraska Gas	148	IBEW Local 244	March 13, 2017
Total	586		

ITEM 1A. RISK FACTORS

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

OPERATING RISKS

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

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

- Our inability to obtain required governmental permits and approvals or the imposition of adverse conditions upon the approval of any acquisition;

- Our inability to secure adequate utility rates through regulatory proceedings;

- Our inability to obtain financing on acceptable terms, or at all;

- The possibility that one or more credit rating agencies would downgrade our issuer credit rating to below investment grade, thus increasing our cost of doing business;

- Our inability to successfully integrate any businesses we acquire;

- Our inability to attract and retain management or other key personnel;

- Our inability to negotiate acceptable acquisition, construction, fuel supply, power sales or other material agreements;

- The trend of utilities building their own generation or looking for developers to develop and build projects for sale to utilities under turnkey arrangements;

- Reduced growth in the demand for utility services in the markets we serve;
- Changes in federal, state, local or tribal laws and regulations, particularly those which would make it more difficult or costly to fully develop our coal reserves, our oil and gas reserves and our generation capacity;
- Fuel prices or fuel supply constraints;
- Pipeline capacity and transmission constraints;

- Competition within our industry and with producers of competing energy sources; and
- Changes in tax rates and policies.

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

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

- Operational limitations imposed by environmental and other regulatory requirements;
- Interruptions to supply of fuel and other commodities used in generation and distribution. The Utilities Group purchases fuel from a number of suppliers. Our results of operations could be negatively impacted by disruptions in the delivery of fuel due to various factors, including but not limited to, transportation delays, labor relations, weather and environmental regulations, which could limit the Utilities Group's ability to operate their facilities;
- Breakdown or failure of equipment or processes, including those operated by PacifiCorp at the Wyodak plant;
- Our ability to transition and replace our retirement-eligible utility employees. At December 31, 2015, approximately 25% of our Utilities Group 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 29% of our employees are represented by a total of six collective bargaining agreements.

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

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

- The inability to obtain required governmental permits and approvals along with the cost of complying with or satisfying conditions imposed upon such approvals;
- Contractual restrictions upon the timing of scheduled outages;
- The cost of supplying or securing replacement power during scheduled and unscheduled outages;
- The unavailability or increased cost of equipment;

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- The cost of recruiting and retaining or the unavailability of skilled labor;
- Supply interruptions, work stoppages and labor disputes;
- Increased capital and operating costs to comply with increasingly stringent environmental laws and regulations;
- Opposition by members of public or special-interest groups;
- Weather interferences;
- Availability and cost of fuel supplies;
- Unexpected engineering, environmental and geological problems; and
- Unanticipated cost overruns.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Utilities

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

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

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

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

We have submitted applications with respective state utility regulators seeking approval for a Cost of Service Gas Program in Iowa, Kansas, Nebraska, South Dakota, Colorado and Wyoming. The implementation of a Cost of Service Gas Program supports our natural gas and electric utilities and provides longer-term price stability for our regulated customers by enhancing our current utility gas supply portfolio, through the addition of affiliate owned natural gas production and reserves. In addition to providing our customers the benefits associated with more predictable long-term natural gas prices, it also provides additional opportunities for increased earnings. We will require regulatory approval from our state commissions to implement this program. If regulatory commissions refuse to approve the program, we may have to reconsider our long-term oil and gas strategy.

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 $360 million of goodwill on our consolidated balance sheets as of December 31, 2015. A substantial portion of the goodwill is related to the Aquila Transaction. If we make changes in our business strategy or if market or other conditions adversely affect operations in any of our businesses, we may be forced to record a non-cash impairment charge, which would reduce our reported assets, net income and shareholders' equity. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. If the testing performed indicates that impairment has occurred, we are required to record an impairment charge for the difference between the carrying value of the goodwill and the implied fair value of the goodwill in the period the determination is made. The testing of goodwill for impairment requires us to make significant estimates about our future performance and cash flows, as well as other assumptions. These estimates can be affected by numerous factors, including: future business operating performance, changes in economic conditions and interest rates, regulatory, industry or market conditions, changes in business operations, changes in competition or changes in technologies. Any changes in key assumptions, or actual performance compared with key assumptions, about our business and its future prospects could affect the fair value of one or more business segments, which may result in an impairment charge.

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

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

Coal Mining

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

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

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

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

Oil and Gas

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

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

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

Hydraulic fracturing is an essential and common practice in the oil and gas industry used extensively for decades to stimulate production of natural gas and/or oil from dense subsurface rock formations. We routinely apply hydraulic fracturing techniques on our crude oil and natural gas properties. Hydraulic fracturing involves using mostly water, sand and a small amount of certain chemicals to fracture the hydrocarbon-bearing rock formation to enhance flow of hydrocarbons into the well-bore. The process is typically regulated by state crude oil and natural gas commissions; however, the EPA does assert federal regulatory authority over certain hydraulic fracturing activities when diesel comprises part of the fracturing fluid. In addition several agencies of the federal government including the EPA and the BLM are conducting studies of the fracturing stimulation process which may result in additional regulations. On March 20, 2015 the U.S. Department of Interior's BLM issued a final rule regulating the use of hydraulic fracturing on federal and Indian Lands. 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. In addition, legislation has been introduced before Congress, called the Fracturing Responsibility and Awareness of Chemicals Act, to provide the federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process.

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

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

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

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

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

We recorded a non-cash impairment charge in 2015 due to the full cost ceiling limitations. Using our year-end reserve information and holding all other variables constant, a price sensitivity analysis indicates it is probable a ceiling impairment charge will occur in 2016 if crude oil and natural gas prices remain at or near the low levels experienced in late 2015 and early 2016. See Note 13 to the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

FINANCING RISKS

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

Our issuer credit rating is Baa1 (Negative 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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

We have deferred a substantial amount of income tax related to various tax planning strategies, including the deferral of a gain associated with the assets sold in the 2008 IPP Transaction. If the Internal Revenue Service successfully challenges these tax positions, our results of operations, financial position or liquidity could be adversely affected.

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

The IRS has challenged our position with respect to the like-kind exchange. As stated in a revised Notice of Proposed Adjustment (NOPA) received from the IRS in April 2013, their position is to disallow a significant portion of the gain deferred as reported on our originally filed 2008 tax return. A 30 Day Letter along with a Revenue Agent's Report were received on July 30, 2014, indicating no change in the IRS’ position. We disagree with such a position and will pursue all available IRS and/or legal channels to challenge the proposed adjustment. A protest was timely filed with IRS Appeals in August 2014. In the event we are unsuccessful in our challenge, the amount of deferred income tax on a worst case basis that could be accelerated into a current taxes payable based on the revised NOPA would be approximately $88 million. However, we would be entitled to a cash tax benefit associated with the additional tax depreciation that would result from increasing the depreciable cost for tax purposes in the assets acquired. This net current tax liability would accrue interest, which is estimated to be approximately $21 million before income tax effect.

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

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

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

ENVIRONMENTAL RISKS

Federal and state laws concerning greenhouse gas regulations and air emissions may materially increase our generation and production costs and could render some of our generating units uneconomical to operate and maintain.

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

On February 16, 2012, the EPA published MATS in the Federal Register with an effective date of April 16, 2012. Affected units had a compliance deadline of April 16, 2015, with a pathway defined to apply for a one year extension due to certain circumstances. We applied for and received a one year extension for mercury only, with the remaining aspects of the MATS rule remaining in effect. All our impacted plants (Neil Simpson II, Wygen I, Wygen II, Wygen III and the Wyodak Plant) are in compliance with the applicable rule provisions.

The GHG Tailoring Rule, implementing regulations of GHG for permitting purposes, became effective in June 2010. This rule will impact us in the event of a major modification at an existing facility or in the event of a new major source as defined by EPA regulations. Upon renewal of operating permits for existing facilities, monitoring and reporting requirements will be implemented. New projects or major modifications to existing projects will result in a Best Available Control Technology review that could impose more stringent emissions control practices and technologies. The EPA’s GHG New Source Performance Standard for new steam electric generating units was published October 23, 2015. That rule 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. This rule may have a significant impact on our coal and natural gas generating fleet. 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. On February 9, 2016, the U.S. Supreme Court entered an order staying the CPP. The stay of the CPP will remain in place until the U.S. Supreme Court either denies a petition for certiorari following the U.S. Court of Appeals’ decision on the substantive challenges to the CPP, if one is submitted, or until the U.S. Supreme Court enters judgment following grant of a petition for certiorari. 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. We do not expect a final judicial decision on challenges to the CPP earlier than mid-2017. In 2015, we met with 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. The impact of GHG legislation or regulation on our company will depend upon many factors, including but not limited to, the timing of implementation, state clean power plan requirements, the GHG sources that are regulated, the overall GHG emissions cap level and the availability of technologies to control or reduce GHG emissions. If an allowance or credit trading structure is implemented, the impact will depend on the allocation of emission allowances to specific sources, the costs of those allowances or credits and the effect of carbon regulation on natural gas and coal prices.

New or more stringent regulations or other energy efficiency requirements could require us to incur significant additional costs relating to, among other things, the installation of additional emission control equipment, the acceleration of capital expenditures, the purchase of additional emissions allowances or offsets, the acquisition or development of additional energy supply from renewable resources, 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 failure to achieve or maintain compliance with existing or future governmental laws, regulations or requirements could adversely affect our results of operations, financial position or liquidity. Additionally, the potentially high cost of complying with such requirements or addressing environmental liabilities could also adversely affect our results of operations, financial position or liquidity.

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

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

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

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

Future regulations may require further reductions in emissions of mercury, hazardous pollutants, SO_2, NOx, volatile organic compounds, particulate matter, and GHG. 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, is designed to cut 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. On February 9, 2016, the U.S. Supreme Court entered an order staying the CPP. The stay of the CPP will remain in place until the U.S. Supreme Court either denies a petition for certiorari following the U.S. Court of Appeals’ decision on the substantive challenges to the CPP, if one is submitted, or until the U.S. Supreme Court enters judgment following grant of a petition for certiorari. 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. We do not expect a final judicial decision on challenges to the CPP earlier than mid-2017. At this time we cannot predict the impact on operations.

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 coal mining operations.

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

RISKS RELATED TO THE SOURCEGAS ACQUISITION

The Transaction may not achieve its intended results, including anticipated operating efficiencies and cost savings, and integration efforts may adversely affect our business, financial condition or results of operations, which may negatively affect the market price of our notes or common stock.

While management currently anticipates that the Transaction will be accretive to our earnings per share beginning in 2017, this expectation is based on preliminary estimates which may materially change. In addition, although we expect that the Transaction will result in various other 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. Achieving the anticipated benefits is subject to a number of uncertainties, including whether the businesses acquired can be operated in the manner we intend. 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. Thus the integration of SourceGas's business may be unpredictable, subject to delays or changed circumstances, and we can give no assurance that the acquired businesses will perform in accordance with our expectations or that our expectations with respect to integration or operating efficiencies as a result of the Transaction will materialize. In addition, our anticipated transaction costs and costs to achieve the integration of SourceGas may differ significantly from our current estimates. The integration may place an additional burden on our management and internal resources, and the diversion of management's attention during the integration process could have an adverse effect on our business, financial condition and expected operating results. Any of these factors could cause a decrease in the price of our notes or common stock.

The Transaction may subject us to other risks.

The Transaction subjects us to a number of additional risks, including the following:

- Uncertainty about the effect of the Transaction on employees, customers, vendors and others may have an adverse effect on us. Although we intend to take steps designed to reduce any adverse effects, these uncertainties may impair our ability to attract, retain and motivate key personnel until the Transaction is completed, and for a period of time thereafter, and could cause vendors and others that deal with us to seek to change existing business relationships.

- We cannot be assured that our credit ratings will not be lowered as a result of the Transaction or for any other reason. Any reduction in our credit ratings could adversely affect our access to capital, our cost of capital and our other operating costs, and our ability to refinance or repay our existing debt and complete new financings.

The occurrence of any of these events individually or in combination could have a material adverse effect on our business, financial condition or results of operations or the trading price of our notes or common stock.

We incurred and assumed significant debt to provide permanent financing for the Transaction and, as a result, we are subject to market risks including market demand for debt offerings, interest rate volatility, and adverse impacts on our credit ratings.

We funded the cash consideration and out-of-pocket expenses payable in connection with the Transaction using the net proceeds (after deducting discounts and fees on the notes) from our $546 million debt offering on January 13, 2016, together with the approximately $535.7 million of net proceeds (after deducting the underwriting discounts and commissions but before offering expenses) from our offerings of common stock and equity units in November 2015, other cash on hand and draws under our revolving credit facility. We assumed approximately $760 million of SourceGas's debt at the closing of the Transaction, reducing the cash consideration payable at closing.

Among other risks, the issuance of the debt may:

- make it more difficult for us to repay or refinance our debts as they become due during adverse economic and industry conditions;

- limit our flexibility to pursue other strategic opportunities or react to changes in our business and the industry in which we operate and, consequently, place us at a competitive disadvantage to competitors with less debt;

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- require an increased portion of our cash flows from operations to be used for debt service payments, thereby reducing the availability of cash flows to fund working capital, capital expenditures, dividend payments and other general corporate purposes;

- result in a downgrade in the credit rating of our indebtedness, which could limit our ability to borrow additional funds or increase the interest rates applicable to our indebtedness;

- result in higher interest expense in the event of increases in market interest rates for both long term debt as well as short term commercial paper, bank loans or borrowings under our line of credit at variable rates;

- reduce the amount of credit available to support hedging activities; and

- require that additional terms, conditions or covenants be placed on us.

We will record goodwill that could become impaired and adversely affect the financial condition and results of operations.

We expect to record a significant amount of goodwill associated with the SourceGas 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.

We incurred significant transaction and acquisition related costs in connection with the Transaction.

We have incurred significant costs associated with the Transaction and we expect to incur significantly more costs as we combine the operations of the two companies, including costs to achieve targeted cost savings. The substantial majority of the expenses resulting from the Transaction are composed of transaction costs, systems consolidation costs, and business integration and employment related costs. We also incurred transaction fees and costs related to formulating integration plans. Additional unanticipated costs may be incurred in the integration of the two companies' businesses. Although we expect that the elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the businesses, should allow us to offset incremental transaction and acquisition related costs over time, this net benefit may not be achieved in the near term, or at all.

Failure to complete future refinancing for our assumed SourceGas debt on favorable terms could have a negative affect on our stock price, and could affect our future business and financial results.

In connection with the Transaction, we are assuming approximately $760 million of SourceGas's indebtedness, which had terms that are less favorable than we believe we can generally obtain in the debt markets. If we are able to refinance the debt, we will incur transaction costs related to the refinancing, and if we are not able to refinance the debt on more favorable terms, it may negatively affect our stock price.

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, 2015, we had 4,041 common shareholders of record and approximately 26,000 beneficial owners, representing all 50 states, the District of Columbia and 10 foreign countries.

We have paid a regular quarterly cash dividend each year since the incorporation of our predecessor company in 1941 and expect to continue paying a regular quarterly dividend for the foreseeable future. At its January 27, 2016 meeting, our Board of Directors declared a quarterly dividend of $0.42 per share, equivalent to an annual dividend of $1.68 per share, marking 2016 as the 46th 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, 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

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

UNREGISTERED SECURITIES ISSUED

There were no unregistered securities sold during 2015.

ISSUER PURCHASES OF EQUITY SECURITIES

There were no equity securities acquired for the three months ended December 31, 2015.

ITEM 6. SELECTED FINANCIAL DATA

Years Ended December 31, (dollars in thousands, except per share amounts)	2015	2014	2013	2012	2011
Total Assets	$4,655,501	$4,245,902	$3,837,936	$3,688,335	$4,053,216
Property, Plant and Equipment					
Total property, plant and equipment	$4,976,778	$4,563,400	$4,259,445	$3,930,772	$3,724,016
Accumulated depreciation and depletion	(1,717,684)	(1,357,929)	(1,306,390)	(1,229,159)	(1,008,307)
Total property, plant and equipment, net	$3,259,094	$3,205,471	$2,953,055	$2,701,613	$2,715,709
Capital Expenditures	$458,821	$391,267	$379,534	$347,980	$431,707
Capitalization					
Current maturities of long-term debt	$—	$275,000	$—	$103,973	$2,473
Notes payable	76,800	75,000	82,500	277,000	345,000
Long-term debt, net of current maturities	1,866,866	1,267,589	1,396,948	938,877	1,280,409
Common stock equity	1,465,867	1,353,884	1,283,500	1,205,800	1,161,715
Total capitalization	$3,409,533	$2,971,473	$2,762,948	$2,525,650	$2,789,597