BLACK HILLS CORP /SD/
Form 10-K
February 26, 2014

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, 2013

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

For the transition period from ____________________ to ___________________

Commission File Number 001-31303

BLACK HILLS CORPORATION

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

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

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

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

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

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

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

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

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

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

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

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

Yes o No x

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

At June 30, 2013 $2,135,998,459

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, 2014
Common stock, $1.00 par value	44,503,454 shares

Documents Incorporated by Reference

Portions of the Registrant's Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2014 Annual Meeting of Stockholders to be held on April 29, 2014, 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:

AFUDC	Allowance for Funds Used During Construction
AltaGas	AltaGas Renewable Energy Colorado LLC, a subsidiary of AltaGas Ltd.
AOCI	Accumulated Other Comprehensive Income
Aquila Transaction	Our July 14, 2008 acquisition of five utilities from Aquila, Inc.
ARO	Asset Retirement Obligations
ASC	Accounting Standards Codification
ASU	Accounting Standards Update as issued by the FASB
ATRA	American Taxpayer Relief Act of 2012
Basin Electric	Basin Electric Power Cooperative
Bbl	Barrel
Bcfe	Billion cubic feet equivalent
BHC	Black Hills Corporation; the Company
BHEP	Black Hills Exploration and Production, Inc., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings, includes Black Hills Gas Resources, Inc. and Black Hills Plateau Production LLC, direct wholly-owned subsidiaries of Black Hills Exploration and Production, Inc.
BHSC	Black Hills Service Company LLC, a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Colorado IPP	Black Hills Colorado IPP, LLC a direct wholly-owned subsidiary of Black Hills Electric Generation
Black Hills Energy	The name used to conduct the business of Black Hills Utility Holdings, Inc., and its subsidiaries
Black Hills Electric Generation	Black Hills Electric Generation, LLC, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
BLM	United States Bureau of Land Management
Btu	British thermal unit
CFTC	United States Commodity Futures Trading Commission
CG&A	Cawley, Gillespie & Associates, Inc., an independent consulting and engineering firm
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation
Cheyenne Light Pension Plan	The Cheyenne Light, Fuel and Power Company Pension Plan
Cheyenne Prairie	Cheyenne Prairie Generating Station currently being constructed in Cheyenne, Wyo. by Cheyenne Light and Black Hills Power. Construction is expected to be completed for this 132 megawatt facility in 2014.
City of Gillette	The City of Gillette, Wyoming, affiliate of the JPB. The JPB financed the purchase of 23 percent of Wygen III power plant for the City of Gillette.
CO_2	Carbon dioxide

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Colorado Electric	Black Hills Colorado Electric Utility Company, LP (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings
Colorado Gas	Black Hills Colorado Gas Utility Company, LP (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings
Cooling Degree Day	A cooling degree day is equivalent to each degree that the average of the high and low temperature for a day is above 65 degrees. The warmer the climate, the greater the number of cooling degree days. Cooling degree days are used in the utility industry to measure the relative warmth of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30 year average.
CPCN	Certificate of Public Convenience and Necessity
CPUC	Colorado Public Utilities Commission
CT	Combustion turbine
CVA	Credit Valuation Adjustment
DART	Days Away Restricted Transferred (number of cases with days away from work or job transfer or restrictions multiplied by 200,000 then divided by total hours worked for all employees during the year covered)
DC	Direct current
De-designated interest rate swaps	The $250 million notional amount interest rate swaps that were originally designated as cash flow hedges under the accounting for derivatives and hedges but subsequently de-designated in December 2008. These swaps were settled in November 2013
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DSM	Demand Side Management
Dth	Dekatherms
EBITDA	Earnings before interest, taxes, depreciation and amortization, a non-GAAP measurement
ECA	Energy Cost Adjustment -- adjustments that allow us to pass the prudently-incurred cost of fuel and purchased energy through to customers.
Economy Energy	Electricity purchased by one utility from another utility to take the place of electricity that would have cost more to produce on the utility’s own system
Enserco	Enserco Energy Inc., a formerly wholly-owned subsidiary of Black Hills Non-regulated Holdings, which is presented in discontinued operations throughout this Annual Report filed on Form 10-K
EPA	United States Environmental Protection Agency
EPA Region VIII	EPA Region VIII (Mountains and Plains) located in Denver serving Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming and 27 Tribal Nations
Equity Forward Agreement	Equity Forward Agreement with J. P. Morgan connected to a public offering of 4,413,519 million shares of Black Hills Corporation common stock, including the over-allotment shares
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.
Idaho generating facilities	Partnership investment owned 50 percent by Black Hills Electric Generation, sold Jan. 18, 2011
IEEE	Institute of Electrical and Electronics Engineers
IFRS	International Financial Reporting Standards
Iowa Gas	Black Hills Iowa Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
IPP	Independent power producer
IPP Transaction	The July 11, 2008 sale of seven of our IPP plants
IRS	United States Internal Revenue Service
IUB	Iowa Utilities Board
JPB	Consolidated Wyoming Municipalities Electric Power System Joint Powers Board. The JPB exists for the purpose of, among other things, financing the electrical system of the City of Gillette
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
kV	Kilovolt
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Loveland Area Project	Part of the Western Area Power Association transmission system
MACT	Maximum Achievable Control Technology
MAPP	Mid-Continent Area Power Pool
MATS	Utility Mercury and Air Toxics Rules under the United States EPA National Emissions Standards for Hazardous Air Pollutants from Coal and Oil Fired Electric Utility Steam Generating Units
Mbbl	Thousand barrels of oil
Mcf	Thousand cubic feet
Mcfe	Thousand cubic feet equivalent
MDU	Montana Dakota Utilities Co., a regulated utility division of MDU Resources Group, Inc.
MEAN	Municipal Energy Agency of Nebraska
MGP	Manufactured Gas Plants
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMcfe	Million cubic feet equivalent
Moody’s	Moody’s Investors Service, Inc.
MSHA	Mine Safety and Health Administration
MTPSC	Montana Public Service Commission
MW	Megawatts
MWh	Megawatt-hours

NA	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 (7 Gallons equals 1 Mcfe)
NOAA	National Oceanic and Atmospheric Administration
NOAA Climate Normals	This dataset is produced once every 10 years. This dataset contains daily and monthly normals of temperature, precipitation, snowfall, heating and cooling degree days, frost/freeze dates, and growing degree days calculated from observations at approximately 9,800 stations operated by NOAA's National Weather Service.
NO_x	Nitrogen oxide
NOL	Net operating loss
NPDES	National Pollutant Discharge Elimination System
NPSC	Nebraska Public Service Commission
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
OSHA	Occupational Safety & Health Administration
PPA	Power Purchase Agreement
PPACA	Patient Protection and Affordable Care Act of 2010
PSCo	Public Service Company of Colorado
PUD	Proved undeveloped reserves
PUHCA 2005	Public Utility Holding Company Act of 2005
RCRA	Resource Conservation and Recovery Act
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 2017
RMSA	Retirement Medical Savings Account
SAIDI	System Average Interruption Duration Index
SDPUC	South Dakota Public Utilities Commission
SEC	U. S. Securities and Exchange Commission
Silver Sage	Silver Sage Windpower, LLC, owned by Duke Energy Generation Services
SO_2	Sulfur dioxide
S&P	Standard & Poor's, a division of The McGraw-Hill Companies, Inc.
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 percent of plants regardless of joint ownership.
TCA	Transmission Cost Adjustment -- adjustments passed through to the customer based on transmission costs that are higher or lower than the costs approved in the rate case.
TCIR	Total Case Incident Rate (average number of work-related injuries incurred by 100 workers during a one-year period)
VEBA	Voluntary Employee Benefit Association
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, S.D. Our predecessor company, Black Hills Power and Light Company, was incorporated and began providing electric utility service in 1941. It was formed through the purchase and combination of several existing electric utilities and related assets, some of which had served customers in the Black Hills region since 1883. In 1956, we began producing, selling and marketing various forms of energy through non-regulated businesses.

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

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

Our Electric Utilities segment generates, transmits and distributes electricity to approximately 203,500 electric customers in South Dakota, Wyoming, Colorado and Montana and also distributes natural gas to approximately 35,500 gas utility customers of Cheyenne Light in and around Cheyenne, Wyo. Our Gas Utilities segment serves approximately 538,000 natural gas utility customers in Colorado, Nebraska, Iowa and Kansas. Our Electric Utilities own 790 megawatts of generation and 8,599 miles of electric transmission and distribution lines, and our Gas Utilities own 604 miles of intrastate gas transmission pipelines and 19,998 miles of gas distribution mains and service lines. Our Utilities Group generated net income of $85 million for the year ended Dec. 31, 2013, and had total assets of $3.3 billion at Dec. 31, 2013.

Our Power Generation segment produces electric power from our generating plants and sells the electric capacity and energy primarily to our utilities under long-term contracts. Our Coal Mining segment produces coal at our coal mine near Gillette, Wyo., and sells the coal primarily under long-term contracts to electric generation facilities including our own regulated and non-regulated generating plants. Our Oil and Gas segment engages in the exploration, development and production of crude oil and natural gas, primarily in the Rocky Mountain region. Our Non-regulated Energy Group generated net income of $18 million for the year ended Dec. 31, 2013, and had total assets of $0.5 billion at Dec. 31, 2013.

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

Segment Financial Information

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

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

Business Group Overview

Utilities Group

We conduct electric utility operations and combination electric and gas utility operations through three subsidiaries: Black Hills Power (South Dakota, Wyoming and Montana), Cheyenne Light (Wyoming), and Colorado Electric (Colorado). Our Electric Utilities generate, transmit and distribute electricity to approximately 203,500 customers; and also distribute natural gas to approximately 35,500 natural gas utility customers of Cheyenne Light in or around Cheyenne, Wyo. Our electric generating facilities and power purchase agreements provide for the supply of electricity principally to our own distribution systems. Additionally, we sell excess power to other utilities and marketing companies, including our affiliates.

We conduct natural gas utility operations on a state-by-state basis through our Colorado Gas, Nebraska Gas, Iowa Gas and Kansas Gas subsidiaries. Our Gas Utilities distribute and transport natural gas through our distribution network to approximately 538,000 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 62,000 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.

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 megawatts)					
	2013		2012		2011	
	Summer	Winter	Summer	Winter	Summer	Winter
Black Hills Power	422	403	449	362	452	408
Cheyenne Light	185	192	187	174	181	175
Colorado Electric	381	280	400	284	392	297
Total Electric Utilities Peak Demands	988	875	1,036	820	1,025	880

Regulated Power Plants

As of Dec. 31, 2013, our Electric Utilities' ownership interests in electric generation plants were as follows:

Unit	Fuel Type	Location	Ownership Interest %	Owned Capacity (MW)	Year Installed
Black Hills Power [1]:					
Wygen III [2]	Coal	Gillette, Wyo.	52%	57.2	2010
Neil Simpson II	Coal	Gillette, Wyo.	100%	90.0	1995
Wyodak [3]	Coal	Gillette, Wyo.	20%	72.4	1978
Osage [4]	Coal	Osage, Wyo.	100%	34.5	1948-1952
Ben French [4]	Coal	Rapid City, S.D.	100%	25.0	1960
Neil Simpson I [4]	Coal	Gillette, Wyo.	100%	21.8	1969
Neil Simpson CT	Gas	Gillette, Wyo.	100%	40.0	2000
Lange CT	Gas	Rapid City, S.D.	100%	40.0	2002
Ben French Diesel #1-5	Oil	Rapid City, S.D.	100%	10.0	1965
Ben French CTs #1-4	Gas/Oil	Rapid City, S.D.	100%	80.0	1977-1979
Cheyenne Light [1]:					
Wygen II	Coal	Gillette, Wyo.	100%	95.0	2008
Colorado Electric [5]:					
Busch Ranch Wind Farm [6]	Wind	Pueblo, Colo.	50%	14.5	2012
Pueblo Airport Generation	Gas	Pueblo, Colo.	100%	180.0	2011
AIP Diesel	Oil	Pueblo, Colo.	100%	10.0	2001
Diesel #1-5	Oil	Pueblo, Colo.	100%	10.0	1964
Diesel #1-5	Oil	Rocky Ford, Colo.	100%	10.0	1964
Total Megawatt Capacity				790.4	

(1) Construction of a 132 megawatt gas-fired power generation facility is underway to support the customers of Black Hills Power and Cheyenne Light. The facility will include one simple-cycle, 37 megawatt combustion turbine that will be wholly owned by Cheyenne Light and one combined-cycle, 95 megawatt unit that will be jointly owned by Cheyenne Light (40 megawatts) and Black Hills Power (55 megawatts). This facility is expected to be completed in the fourth quarter of 2014.

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

(3) Wyodak, a 362 megawatt mine-mouth coal-fired power plant, is owned 80 percent by PacifiCorp and 20 percent 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) Operations at Osage were suspended Oct. 1, 2010, and Ben French was suspended on Aug. 31, 2012, due to the availability of more economical generation alternatives when evaluating costs to retrofit these plants to comply with environmental standards, including EPA regulations. Osage, Ben French and Neil Simpson I will be retired on or before March 21, 2014. While the net book value of these plants is estimated to be immaterial at the time of retirement, we would reasonably expect any remaining value to be recovered through future rates and costs will be deferred as Regulatory assets on the accompanying Consolidated Balance Sheets.

(5) Colorado Electric's W.N. Clark (42 megawatts) and Pueblo Units #5 and #6 (29 megawatts) were retired as of Dec. 31, 2013.

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

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

Fuel Source (dollars per megawatt-hour)	2013	2012	2011
Coal	$10.89	$14.42	$15.89
Natural Gas	$53.53	$52.08	$74.64
Diesel Oil	$233.47	$280.29	$405.47
Total Average Fuel Cost	$14.65	$16.05	$16.77
Purchased Power - Coal, Gas and Oil	$29.95	$26.70	$28.80
Purchased Power - Renewable Sources	$49.20	$47.45	$46.71

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

Power Supply	2013	2012	2011
Coal	36 %	37 %	38 %
Gas, Oil and Wind	4	2	—
Total Generated	40	39	38
Purchased	60	61	62
Total	100 %	100 %	100 %

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

- Black Hills Power's PPA with PacifiCorp expiring on Dec. 31, 2023, which provides for the purchase of 50 megawatts of coal-fired baseload power;
- Colorado Electric's PPA with Black Hills Colorado IPP expiring on Dec. 31, 2031, which provides 200 megawatts of energy and capacity to Colorado Electric from Black Hills Colorado IPP's combined-cycle turbines. This PPA is accounted for as a capital lease on the accompanying Consolidated Financial Statements;
- Colorado Electric's PPA with Cargill expiring on Dec. 31, 2014, whereby Colorado Electric purchases between 25 megawatts and 50 megawatts of economy energy based on various timing intervals throughout 2014;
- Colorado Electric's PPA with AltaGas expiring on Oct. 16, 2037, which provides up to 14.5 megawatts of wind energy from AltaGas' owned interest in the Busch Ranch Wind Project;
- Cheyenne Light's PPA with Black Hills Wyoming expiring on Aug. 31, 2014, whereby Black Hills Wyoming provides 40 megawatts of energy and capacity from its Gillette CT;
- Cheyenne Light's PPA with Black Hills Wyoming expiring on Dec. 31, 2022, whereby Black Hills Wyoming provides 60 megawatts of unit-contingent capacity and energy from its Wygen I facility. The PPA includes an option for Cheyenne Light to purchase Black Hills Wyoming's ownership interest in the Wygen I facility through 2019. The purchase price related to the option is $2.6 million per megawatt adjusted for capital additions and reduced by depreciation over a 35 year life beginning Jan. 1, 2009 (approximately $5 million per year);
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Cheyenne Light's 20-year PPA with Duke Energy expiring on Sept. 3, 2028, which provides up to 29.4 megawatts of wind energy from the Happy Jack Wind Farm to Cheyenne Light. Under a separate inter-company agreement, Cheyenne Light sells 50 percent of the facility's output to Black Hills Power;

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

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

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

- MDU owns a 25 percent ownership 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 megawatts from its other generation facilities or from system purchases with reimbursement of costs by MDU;

- The City of Gillette owns a 23 percent ownership 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 megawatts from its other generation facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement, Black Hills Power will also provide the City of Gillette its operating component of spinning reserves;

- Black Hills Power's agreement to supply up to 20 megawatts 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:

2014-2017	20 megawatts - 10 megawatts contingent on Wygen III and 10 megawatts contingent on Neil Simpson II
2018-2019	15 megawatts - 10 megawatts contingent on Wygen III and 5 megawatts contingent on Neil Simpson II
2020-2021	12 megawatts - 6 megawatts contingent on Wygen III and 6 megawatts contingent on Neil Simpson II
2022-2023	10 megawatts - 5 megawatts contingent on Wygen III and 5 megawatts contingent on Neil Simpson II;

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

- Cheyenne Light's agreement with Basin Electric, whereby Cheyenne Light will supply 40 megawatts of capacity and energy through Sept. 30, 2014, and a separate agreement whereby Cheyenne Light will receive 40 megawatts of capacity and energy from Basin Electric through Sept. 30, 2014.

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 Dec. 31, 2013, 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	2,462
Black Hills Power - Jointly Owned [(1)]	South Dakota, Wyoming	44	—

Cheyenne Light	South Dakota, Wyoming	25	1,246
Colorado Electric	Colorado	581	3,062

(1) Black Hills Power owns 35 percent 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 percent 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 megawatts from West to East, and 200 megawatts 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 megawatts 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, Wyo., 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.

- 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	2013		2012		2011	
	Actual	Variance from 30-Year Average (b)	Actual	Variance from 30-Year Average (b)	Actual	Variance from 30-Year Average (b)
Heating Degree Days:						
Black Hills Power	7,582	9%	6,206	(13)%	7,579	5%
Cheyenne Light	7,386	4%	6,304	(11)%	7,321	(1)%
Colorado Electric	5,740	1%	4,921	(13)%	5,749	3%
Combined (a)	6,691	5%	5,629	(12)%	6,675	4%
Cooling Degree Days:						
Black Hills Power	724	8%	937	47%	700	17%
Cheyenne Light	520	48%	568	63%	431	58%
Colorado Electric	1,230	28%	1,322	47%	1,259	37%
Combined (a)	918	24%	1,043	47%	908	33%

(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)	2013	2012	2011
Residential:			
Black Hills Power	$64,566	$58,523	$59,826
Cheyenne Light	35,778	32,053	31,287
Colorado Electric [(a)]	95,631	91,550	84,646
Total Residential	195,975	182,126	175,759
Commercial:			
Black Hills Power	80,289	73,858	72,889
Cheyenne Light	57,444	55,600	55,331
Colorado Electric	87,732	82,849	73,355
Total Commercial	225,465	212,307	201,575
Industrial:			
Black Hills Power	27,705	25,656	25,723
Cheyenne Light	20,803	16,105	11,629
Colorado Electric	38,037	37,540	33,332
Total Industrial	86,545	79,301	70,684
Municipal:			
Black Hills Power	3,421	3,268	3,172
Cheyenne Light	1,918	1,807	1,765
Colorado Electric	13,106	13,373	12,912
Total Municipal	18,445	18,448	17,849
Subtotal Retail Revenue - Electric	526,430	492,182	465,867
Contract Wholesale:			
Total Contract Wholesale - Black Hills Power	21,956	20,290	18,105
Off-system/Power Marketing Wholesale:			
Black Hills Power	29,580	31,905	34,889
Cheyenne Light	8,712	8,365	9,371
Colorado Electric [(b)]	8,329	6,003	13,018
Total Off-system/Power Marketing Wholesale	46,621	46,273	57,278
Other Revenue: [(c)]			
Black Hills Power	26,510	29,809	31,027
Cheyenne Light	1,916	2,336	2,449
Colorado Electric	4,612	4,652	2,787
Total Other Revenue	33,038	36,797	36,263
Total Revenue - Electric	$628,045	$595,542	$577,513

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

(b) Off-system sales revenue during part of 2010 was deferred until a sharing mechanism was approved by the CPUC in December 2011. As a result, Colorado Electric had deferred $8.4 million in off-system revenue which was all recognized in December 2011.

(c) Other revenue primarily consists of transmission revenue.

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Quantities Generated and Purchased (megawatt-hour)	2013	2012	2011
Generated -			
Coal-fired:			
Black Hills Power	1,768,483	1,796,936	1,717,008
Cheyenne Light	688,318	587,832	674,518
Colorado Electric [(a)]	—	222,647	268,317
Total Coal - fired	2,456,801	2,607,415	2,659,843
Natural Gas and Oil:			
Black Hills Power	33,374	33,183	15,221
Cheyenne Light	—	—	—
Colorado Electric	247,758	84,874	2,342
Total Natural Gas and Oil	281,132	118,057	17,563
Wind:			
Colorado Electric	45,765	12,433	—
Total Wind	45,765	12,433	—
Total Generated:			
Black Hills Power	1,801,857	1,830,119	1,732,229
Cheyenne Light	688,318	587,832	674,518
Colorado Electric	293,523	319,954	270,659
Total Generated	2,783,698	2,737,905	2,677,406
Purchased -			
Black Hills Power	1,441,286	1,678,090	1,720,640
Cheyenne Light	779,677	807,659	745,983
Colorado Electric	1,886,627	1,794,229	1,948,321
Total Purchased [(b)]	4,107,590	4,279,978	4,414,944
Total Generated and Purchased	6,891,288	7,017,883	7,092,350

(a) W.N. Clark suspended operations in 2012.

(b) Includes wind power of 222,069 megawatt-hours, 199,079 megawatt-hours and 189,255 megawatt-hours in 2013, 2012 and 2011, respectively.

Quantities (megawatt-hour)	2013	2012	2011
Residential:			
Black Hills Power	555,204	532,342	550,935
Cheyenne Light	272,490	261,792	264,492
Colorado Electric	619,857	614,521	629,752
Total Residential	1,447,551	1,408,655	1,445,179
Commercial:			
Black Hills Power	730,701	731,785	720,978
Cheyenne Light	544,636	577,141	601,162
Colorado Electric	703,604	723,216	720,060
Total Commercial	1,978,941	2,032,142	2,042,200
Industrial:			
Black Hills Power	404,009	407,301	408,337
Cheyenne Light	281,727	224,448	172,840
Colorado Electric	371,102	358,490	351,862
Total Industrial	1,056,838	990,239	933,039
Municipal:			
Black Hills Power	34,344	35,933	34,235
Cheyenne Light	9,848	9,631	9,827
Colorado Electric	114,732	121,480	126,320
Total Municipal	158,924	167,044	170,382
Subtotal Retail Quantity Sold	4,642,254	4,598,080	4,590,800
Contract Wholesale:			
Total Contract Wholesale - Black Hills Power	357,193	340,036	349,520
Off-system Wholesale:			
Black Hills Power	1,002,847	1,263,457	1,226,548
Cheyenne Light	234,566	229,062	278,528
Colorado Electric	219,349	160,430	282,929
Total Off-system Wholesale	1,456,762	1,652,949	1,788,005
Total Quantity Sold:			
Black Hills Power	3,084,298	3,310,854	3,290,553
Cheyenne Light	1,343,267	1,302,074	1,326,849
Colorado Electric	2,028,644	1,978,137	2,110,923
Total Quantity Sold	6,456,209	6,591,065	6,728,325
Other Uses, Losses or Generation, net [(a)]:			
Black Hills Power	158,845	197,355	162,316
Cheyenne Light	124,728	93,417	93,652
Colorado Electric	151,506	136,046	108,057
Total Other Uses, Losses and Generation, net	435,079	426,818	364,025
Total Energy	6,891,288	7,017,883	7,092,350

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

Customers at End of Year	2013	2012	2011
Residential:			
Black Hills Power	55,840	55,296	54,955
Cheyenne Light	35,780	35,438	35,159
Colorado Electric	82,371	81,795	81,811
Total Residential	173,991	172,529	171,925
Commercial:			
Black Hills Power	12,888	12,857	12,864
Cheyenne Light	4,471	4,276	4,277
Colorado Electric	11,060	11,220	11,206
Total Commercial	28,419	28,353	28,347
Industrial:			
Black Hills Power	46	44	45
Cheyenne Light	3	2	2
Colorado Electric	61	61	68
Total Industrial	110	107	115
Other Electric Customers:			
Black Hills Power	310	308	311
Cheyenne Light	232	240	243
Colorado Electric	469	475	506
Total Other Electric Customers	1,011	1,023	1,060
Subtotal Retail Customers	203,531	202,012	201,447
Contract Wholesale:			
Total Contract Wholesale - Black Hills Power	3	3	3
Total Customers:			
Black Hills Power	69,087	68,508	68,178
Cheyenne Light	40,486	39,956	39,681
Colorado Electric	93,961	93,551	93,591
Total Electric Customers at End of Year	203,534	202,015	201,450

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:

	2013	2012	2011
Revenue - Gas (in thousands):			
Residential	$23,047	$19,327	$22,044
Commercial	10,326	8,613	10,264
Industrial	3,050	2,715	3,597
Other Sales Revenue	840	769	913
Total Revenue - Gas	$37,263	$31,424	$36,818
Gross Margin - Gas (in thousands):			
Residential	$12,706	$10,712	$10,426
Commercial	3,993	2,963	3,345
Industrial	598	551	504
Other Gross Margin	881	766	545
Total Gross Margin - Gas	$18,178	$14,992	$14,820
Quantities Sold (Dth):			
Residential	2,728,797	2,215,858	2,585,056
Commercial	1,653,021	1,447,522	1,538,616
Industrial	652,539	598,408	689,935
Total Quantities Sold	5,034,357	4,261,788	4,813,607
Gas Customers at Year-End	35,494	35,021	34,807

Gas Utilities Segment

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

System Infrastructure (in line miles) as of Dec. 31, 2013	Intrastate Gas Transmission Pipelines	Gas Distribution Mains	Gas Distribution Service Lines
Colorado	126	3,011	917
Nebraska	44	3,468	3,509
Iowa	170	2,653	2,433
Kansas	264	2,701	1,306
Total	604	11,833	8,165

Degree Days

	2013		2012		2011	
	Actual	Variance From 30-Year Average (c)	Actual	Variance From 30-Year Average (c)	Actual	Variance From 30-Year Average (c)
Heating Degree Days:						
Colorado	6,310	1%	5,186	(18)%	5,991	(7)%
Nebraska	6,516	8%	5,198	(15)%	6,190	(1)%
Iowa	7,743	14%	6,093	(10)%	7,013	(4)%
Kansas [(a)]	5,294	8%	4,190	(15)%	4,954	(1)%
Combined [(b)]	6,922	9%	5,518	(13)%	6,455	(3)%

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(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)	2013	2012	2011
Residential:			
Colorado	$53,296	$48,406	$58,102
Nebraska	122,197	98,339	125,493
Iowa	98,498	82,669	106,292
Kansas	67,501	55,096	65,185
Total Residential	341,492	284,510	355,072
Commercial:			
Colorado	10,515	9,558	12,172
Nebraska	37,190	30,894	40,659
Iowa	47,494	36,550	46,179
Kansas	21,440	15,677	20,362
Total Commercial	116,639	92,679	119,372
Industrial:			
Colorado	1,661	1,963	2,063
Nebraska	900	876	860
Iowa	3,436	2,458	2,521
Kansas	15,753	13,614	19,571
Total Industrial	21,750	18,911	25,015
Other:			
Colorado	(17)	181	96
Nebraska	2,265	2,066	1,971
Iowa	543	452	550
Kansas	2,326	5,124	3,031
Total Other Sales Revenue	5,117	7,823	5,648
Distribution:			
Colorado	65,455	60,108	72,433
Nebraska	162,552	132,175	168,983
Iowa	149,971	122,129	155,542
Kansas	107,020	89,511	108,149
Total Distribution	484,998	403,923	505,107
Transportation:			
Colorado	1,033	866	846
Nebraska	12,943	10,589	11,175
Iowa	4,809	4,128	3,935
Kansas	6,472	5,762	5,909
Total Transportation	25,257	21,345	21,865
Total Regulated Revenue	510,255	425,268	526,972
Non-regulated Services	29,434	28,813	27,612
Total Revenue	$539,689	$454,081	$554,584

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Gross Margin (in thousands)	2013	2012	2011
Residential:			
Colorado	$18,244	$16,400	$17,711
Nebraska	53,367	46,982	51,640
Iowa	42,961	39,561	47,491
Kansas	32,111	28,734	29,701
Total Residential	146,683	131,677	146,543
Commercial:			
Colorado	3,009	2,680	2,960
Nebraska	11,560	10,201	11,643
Iowa	13,060	11,071	11,702
Kansas	7,436	6,097	6,603
Total Commercial	35,065	30,049	32,908
Industrial:			
Colorado	519	581	450
Nebraska	250	249	217
Iowa	321	257	288
Kansas	2,220	2,362	2,373
Total Industrial	3,310	3,449	3,328
Other:			
Colorado	(17)	181	96
Nebraska	2,266	2,066	1,971
Iowa	543	452	549
Kansas	1,723	4,787	2,455
Total Other Sales Margins	4,515	7,486	5,071
Distribution:			
Colorado	21,755	19,842	21,217
Nebraska	67,443	59,498	65,471
Iowa	56,885	51,341	60,030
Kansas	43,490	41,980	41,132
Total Distribution	189,573	172,661	187,850
Transportation:			
Colorado	1,033	866	846
Nebraska	12,943	10,589	11,175
Iowa	4,809	4,128	3,935
Kansas	6,472	5,762	5,909
Total Transportation	25,257	21,345	21,865
Total Regulated Gross Margin:			
Colorado	22,788	20,708	22,063
Nebraska	80,386	70,087	76,646
Iowa	61,694	55,469	63,965
Kansas	49,962	47,742	47,041
Total Regulated Gross Margin	214,830	194,006	209,715

Non-regulated Services	14,396	14,726	12,908
Total Gross Margin	$229,226	$208,732	$222,623

Distribution Quantities Sold and Transportation (in Dth)	2013	2012	2011
Residential:			
Colorado	6,969,741	5,869,817	6,437,860
Nebraska	12,717,565	9,555,073	12,076,979
Iowa	11,359,220	8,732,301	10,490,129
Kansas	7,174,085	5,681,199	6,853,163
Total Residential	38,220,611	29,838,390	35,858,131
Commercial:			
Colorado	1,506,227	1,284,082	1,472,747
Nebraska	4,770,370	3,952,067	4,833,604
Iowa	7,056,978	5,304,162	6,192,167
Kansas	2,867,696	2,121,063	2,676,439
Total Commercial	16,201,271	12,661,374	15,174,957
Industrial:			
Colorado	405,047	463,566	344,576
Nebraska	150,227	158,445	120,779
Iowa	648,173	492,633	409,723
Kansas	3,355,930	3,675,678	3,743,735
Total Industrial	4,559,377	4,790,322	4,618,813
Wholesale and Other:			
Kansas	116,234	68,419	112,253
Total Wholesale and Other	116,234	68,419	112,253
Distribution Quantities Sold:			
Colorado	8,881,015	7,617,465	8,255,183
Nebraska	17,638,162	13,665,585	17,031,362
Iowa	19,064,371	14,529,096	17,092,019
Kansas	13,513,945	11,546,359	13,385,590
Total Distribution Quantities Sold	59,097,493	47,358,505	55,764,154
Transportation:			
Colorado	1,015,791	850,156	869,570
Nebraska	28,171,610	26,649,759	24,972,560
Iowa	20,176,525	18,294,228	18,358,692
Kansas	14,457,620	14,686,679	15,015,310
Total Transportation	63,821,546	60,480,822	59,216,132
Total Distribution Quantities Sold and Transportation:			
Colorado	9,896,806	8,467,621	9,124,753
Nebraska	45,809,772	40,315,344	42,003,922
Iowa	39,240,896	32,823,324	35,450,711
Kansas	27,971,565	26,233,038	28,400,900
Total Distribution Quantities Sold and Transportation	122,919,039	107,839,327	114,980,286

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Customers at End of Year	2013	2012	2011
Residential:			
Colorado	70,410	68,927	67,496
Nebraska	178,389	176,953	176,386
Iowa	137,525	135,897	135,161
Kansas	99,315	98,516	98,043
Total Residential	485,639	480,293	477,086
Commercial:			
Colorado	3,737	3,681	3,678
Nebraska	15,739	15,626	15,664
Iowa	15,418	15,398	15,398
Kansas	9,832	9,584	9,453
Total Commercial	44,726	44,289	44,193
Industrial:			
Colorado	207	213	209
Nebraska	136	136	141
Iowa	94	94	94
Kansas	1,358	1,261	1,365
Total Industrial	1,795	1,704	1,809
Transportation:			
Colorado	36	36	30
Nebraska	4,240	4,115	4,128
Iowa	421	412	393
Kansas	1,171	1,166	1,142
Total Transportation	5,868	5,729	5,693
Wholesale:			
Kansas	7	7	7
Total Wholesale	7	7	7
Total Customers:			
Colorado	74,390	72,857	71,413
Nebraska	198,504	196,830	196,319
Iowa	153,458	151,801	151,046
Kansas	111,683	110,534	110,010
Total Customers at End of Year	538,035	532,022	528,788

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. In the past, various restructuring and competitive initiatives have been discussed in several of the states in which our utilities operate, but none of these initiatives have been adopted to date, with the exception of Montana. 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	SD	Global Settlement	7.93%	Global Settlement	$440.2	6/2013	ECA, TCA, Energy Efficiency Cost Recovery/DSM	65%
	SD		8.16%			6/2011	Environmental Improvement Cost Recovery Adjustment Tariff	NA
	WY	10.5%	8.6%	48%/52%	$27.0	6/2010	ECA, TCA	50% subject to symmetrical deadband
	MT	15.0%	11.7%	47%/53%		1983	ECA	NA
	FERC	10.8%	9.1%	43%/57%		2/2009	FERC Transmission Tariff	NA
Cheyenne Light - Electric	WY	9.6%	8.0%	46%/54%	$243.5	7/2012	ECA, Energy Efficiency Cost Recovery/DSM, Rate Base Recovery on Acquisition Adjustment	NA
Cheyenne Light - Gas	WY	9.6%	8.0%	46%/54%	$43.6	7/2012	GCA, Energy Efficiency Cost Recovery/DSM, Rate Base Recovery of Acquisition Adjustment	NA
Colorado Electric	CO	9.8%-10.2%	8.5%	50.9%/49.1%	$405.7	1/2012	ECA, TCA, Energy Efficiency Cost Recovery/DSM, Renewable Energy Standard Adjustment	75% through 2013; 90% thereafter
Gas Utilities:								
Colorado Gas	CO	9.6%	8.4%	50%/50%	$64.0	12/2012	GCA, Energy Efficiency Cost Recovery/DSM	NA
Nebraska Gas	NE	10.1%	9.1%	48%/52%	$161.0	9/2010	GCA, Cost of Bad Debt Collected through GCA, Infrastructure System Replacement Cost Recovery Surcharge	NA
Kansas Gas	KS	Global Settlement	Global Settlement	49.3%/50.7%	$80.9	6/2007	GCA, Weather Normalization Tariff,	NA

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

We produce and/or distribute electricity in four states: Colorado, Montana, South Dakota and Wyoming. 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 with these adjustments.

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

- In September 2013, the SDPUC approved a construction financing rider for Black Hills Power effective April 1, 2013, which allows for recovery of construction financing costs from customers during the construction period of Cheyenne Prairie in lieu of traditional AFUDC. The rider allows Black Hills Power to earn and collect a rate of return during the construction period on the total project cost that relates to South Dakota customers. This rider is similar to the rider approved by WPSC effective Nov. 1, 2012, which allows Cheyenne Light and Black Hills Power to earn and collect a rate of return during the construction period of Cheyenne Prairie on approximately 60 percent of the total project cost that relates to Wyoming customers. These riders increased gross margin by approximately $6.9 million in 2013.

- In Wyoming, Cheyenne Light has annual cost adjustment mechanisms that allow us to pass the prudently-incurred cost of fuel and purchased power through to electric customers. Until July 1, 2012, at Cheyenne Light, our pass-through mechanism relating to transmission and the ECA was subject to a $1.0 million threshold: we collected or refunded 95 percent of the increase or decrease that exceeded the $1.0 million threshold, and we absorbed the increase or retained the savings for costs below the threshold as well as the 5 percent not collected or refunded above the threshold. Effective July 1, 2012, the $1.0 million threshold and its accompanying 95/5 percent distribution methodology was eliminated and replaced by a sharing mechanism that returned 85 percent to the customer and allowed the company to retain 15 percent.

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

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

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

- In Colorado, we have a quarterly ECA rider (the rider was semi-annual until Aug. 1, 2013) that allows us to recover forecasted increases or decreases in purchased energy and fuel costs, including the recovery for amounts payable to others for the transmission of the utility's electricity over transmission facilities owned by others, symmetrical interest, and the sharing of off-system sales margins, less certain operating costs, where the customer received 75 percent through 2013. This sharing percentage increases to 90 percent to the customers in 2014 and thereafter. 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 us an annual Transmission Cost Adjustment (TCA) rider, from which we recover nine months of actual transmission investment and three months of forecasted investment, with an annual true-up mechanism.

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 weather normalization tariff that provides a pass-through mechanism for weather margin variability that occurs from the level used to establish base rates to be paid by the customer, as well as tariffs that provide for more timely recovery for certain capital expenditures and fluctuations in property taxes.

- 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.

Pending Rates and Rate Activity

The following 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
Iowa Gas [(1)]	Gas	12/2012	4/25/2013	$0.9	$0.2
Black Hills Power [(2)]	Electric	12/2012	6/16/2013	$13.7	$8.8
Black Hills Power [(3)]	Electric	12/2012	4/1/2013	$9.2	$7.7
Nebraska Gas [(4)]	Gas	8/2013	11/2013	$1.4	$1.4
Cheyenne Light [(5)]	Electric/Gas	12/2013	pending	$14.1	pending
Black Hills Power [(6)]	Electric	01/2014	pending	$2.8	pending

(1) Iowa Gas filed a request for a Capital Infrastructure Automatic Adjustment Mechanism with the IUB in December 2012, which reflected a request for recovery of costs since our prior rate case in 2010. On March 15, 2013, the IUB determined that certain capital infrastructure investments were not eligible for recovery through this mechanism and on March 26, 2013, Iowa Gas filed a revised proposed tariff. On April 15, 2013, the IUB approved a Capital Infrastructure Automatic Adjustment Mechanism effective April 25, 2013 for $0.2 million. This adjustment mechanism requires an annual filing. Therefore, subsequent filings will vary in size based on eligible infrastructure replacements and the timing of future general rate case filings.

(2) In December 2012, Black Hills Power filed a rate case with the SDPUC requesting an electric revenue increase of $13.7 million, or 9.94 percent, to recover investment in distribution and transmission lines, generation plant upgrades, environmental compliance and increased operating costs. On Sept. 17, 2013, the SDPUC approved a rate increase of $8.8 million, or 6.4 percent, effective June 16, 2013.

(3) In December 2012, Black Hills Power filed a request with the SDPUC to use a construction financing rider during the construction of Cheyenne Prairie in lieu of traditional AFUDC. This rider is similar to the one approved by the WPSC in 2012 for Cheyenne Light and Black Hills Power for Wyoming customers. On Jan. 17, 2013, the SDPUC approved a stipulation with interim rates effective April 1, 2013, and on Sept. 17, 2013, the SDPUC approved the construction financing rider effective April 1, 2013. The rider allows Black Hills Power to earn and collect a rate of return during the construction period on its approximately 40 percent share of the total project cost that relates to South Dakota customers.

(4) In August 2013, Nebraska Gas filed with the NPSC an application requesting authority to establish an Infrastructure System Replacement Cost Recovery Charge mechanism. In an order dated Nov. 25, 2013, the NPSC approved a settlement with the Public Advocate that provided for a revenue increase of $1.4 million.

(5) In December 2013, Cheyenne Light filed a rate case with the WPSC requesting electric and natural gas revenue increases of $12.8 million and $1.3 million, respectively, to recover investment in Cheyenne Prairie, existing infrastructure and increased operating costs. The filing seeks a return on equity of 10.25 percent and a capital structure of 54 percent equity and 46 percent debt.

(6) In January 2014, Black Hills Power filed a rate case with the WPSC requesting an electric revenue increase of $2.8 million to recover investment in Cheyenne Prairie, existing infrastructure and increasing operating costs. The filing seeks a return on equity of 10.25 percent and a capital structure of 53 percent equity and 47 percent debt.

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 Dec. 31, 2013, 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 two percent 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) 12 percent of retail sales through 2014; (ii) 20 percent of retail sales from 2015 to 2019; and (iii) 30 percent of retail sales by 2020. Of these amounts, 3 percent 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 percent. 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. In 2014, our Colorado Electric subsidiary will conduct an all-source solicitation to acquire additional electricity which may include electricity from renewable energy resources. In 2014, our Colorado Electric subsidiary will also file its renewable energy standard plan with the CPUC for the years 2015 through 2017.

- 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. However, 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 percent 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, Black Hills Service Company and Black Hills Utility Holdings, we are subject to FERC's authority under PUHCA 2005.

Environmental Matters

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

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

Environmental Expenditure Estimates	Total (in millions)
2014	$5.7
2015	4.5
2016	5.1
Total	$15.3

Water Issues

Our facilities are subject to a variety of state and federal regulations governing existing and potential water/wastewater discharges and protection of surface waters from oil pollution. Generally, such regulations are promulgated under the Clean Water Act and govern overall water/wastewater discharges through NPDES and stormwater 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, with an estimated implementation date of May 2014. These rules may have an impact on the Wyodak Plant, potentially requiring a modification to the methods of handling coal ash. Additionally, the EPA regulates surface water oil pollution through its oil pollution prevention regulations. All of our facilities subject to these regulations have compliant prevention plans in place.

Air Emissions

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

Clean Air Act

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

Title IV applies to several of our generation facilities, including the Neil Simpson II, Neil Simpson CT II, 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 2043. 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 and Pueblo Airport Generating Station. Wygen III and Pueblo Airport 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 2014. The Pueblo Airport Generating Station Title V application was filed in September 2012, with the permit expected in 2014. Both 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 Dec. 21, 2012, which impose emission limits, fuel requirements and monitoring requirements. The rule has 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 Aug. 31, 2012. We plan to permanently retire Osage, Ben French and Neil Simpson I on or before 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 Dec. 31, 2013. The W.N. Clark facility suspended operations Dec. 31, 2012, and was retired on Dec. 31, 2013, in accordance with the Colorado Clean Air Clean Jobs Act.

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

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. New projects or major modifications to existing projects will result in a Best Available Control Technology review that could result in more stringent emission control practices and technologies. Wyoming passed GHG legislation in 2012 and 2013, enabling the state to implement EPA’s GHG program. Wyoming adopted and submitted a GHG regulatory program to the EPA, which the EPA approved and published in the Nov. 22, 2013 Federal Register. As of Dec. 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.

On Jan. 8, 2014, the EPA re-proposed Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units. These standards may apply to the LM 6000 to be constructed by Colorado Electric at Pueblo Airport Generating Station that is currently under permit review. As proposed, the rule will limit simple-cycle turbines to one-third of their generating capacity based on a three-year average. We expect multiple revisions and legal actions before the final rule is issued, so we cannot be certain of impacts from this rule.

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 2014 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 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 is expected to propose a more stringent ozone ambient air standard in 2014. If the lower range of the proposed standard is selected, it is anticipated that Campbell County, Wyoming would be a non-attainment area. Under those conditions, the State of Wyoming may evaluate Neil Simpson II, Wygen II and Wygen III for further reductions in NO_x emissions.

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

Regional Haze

In January 2011, the states of Wyoming and South Dakota submitted their plans to EPA Region VIII, identifying NO_x, SO_2 and particulate matter emission reductions intended to meet the Class I Areas (National Parks and Wilderness Areas) visibility improvement requirements under the EPA's Regional Haze Program. Although none of our South Dakota or Wyoming power plants were included in those plans, we anticipate that in the next required revisions due in 2016, some of our plants will be included. Ben French, Osage and Neil Simpson I will be permanently retired on or prior to March 21, 2014. If this was not the case, it is highly probable these plants along with Neil Simpson II, would be included in revised regulations.

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

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

Plant	Company	Megawatts	Type of Plant	Date Suspended	Planned or Actual Retirement Date	Age of Plant (in years)
Osage	Black Hills Power	34.5	Coal	Oct. 1, 2010	March 21, 2014	64
Ben French	Black Hills Power	25.0	Coal	Aug. 31, 2012	March 21, 2014	52

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

In addition, Neil Simpson II is expected to be included in the Wyoming Regional Haze Plan update due to the EPA in 2016. The Wyodak Power Plant is included in EPA's currently proposed Regional Haze Federal Implementation Plan, which includes additional NOx controls. On Jan. 30, 2014, the EPA published the final Wyoming Regional Haze Federal Implementation Plan in the Federal Register, which requires significant NO_x control upgrades to be completed at the Wyodak Power Plant within five years. Our share of those costs is estimated at $20 million. We anticipate this ruling will be litigated.

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. The EPA intends to finalize the first GHG emission standards sometime in June 2014, which will apply to new steam electric generating units, as described above. This rule, with its very low proposed CO_2 emissions standards, effectively prohibits new coal-fired power plants from being constructed until carbon capture and sequestration becomes technically and economically feasible. It also restricts simple-cycle natural gas turbines to one-third of their generating capacity based on a three-year average. The EPA will also be developing GHG emission standards for existing steam electric generating units. We expect the EPA to issue a proposed rule in 2014 and while we cannot predict the terms of the regulation, any federally mandated GHG reductions or limits on CO_2 emissions at our existing plants could have a material impact on our customer rates, financial position, results of operations and/or cash flows. In 2011, the EPA's GHG Tailoring Rule went into effect, requiring GHG emissions to be addressed in new major source construction permits, and to be addressed upon renewal of Title V Operating Permits. Since there are no emission standards or caps currently in place, we cannot predict how this requirement will impact our existing facilities upon permit renewal. In 2013, we reported 2011 GHG emissions from our Power Generation and Gas Utilities in order to comply with the EPA's GHG Annual Inventory regulation, issued in 2009. We continue to report annual GHG emissions as required by the EPA. In addition to federal legislative activity, GHG regulations have been proposed in various states and alleged climate change issues are the subject of a number of lawsuits, the outcome of which could impact the utility industry. We will continue to review GHG impacts as legislation or regulation develops and litigation is resolved.

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

Solid Waste Disposal

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

As of Oct. 1, 2010, we suspended operations at the Osage power plant and it is scheduled to be retired on or before March 21, 2014. This plant has an on-site ash impoundment that is near capacity. An application to close the impoundment was approved on April 13, 2012. Site closure work was completed and 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 post closure monitoring will continue for 30 years. As of Aug. 31, 2012, we suspended operations at Ben French, which is scheduled to close on or before March 21, 2014. We will also close Neil Simpson I on or before March 21, 2014.

Our W.N. Clark plant, which suspended operations on Dec. 31, 2012 and was retired on Dec. 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 site in Pueblo, Colo., 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 agreement, Black Hills Power, MDU and the City of Gillette each share the costs for solid waste from Wygen III according to their respective ownership interests.

Additional unexpected material costs could also result in the future if any regulatory agency determines that solid waste from the burning of coal contains a hazardous material that requires special treatment, including previously disposed solid waste. In that event, the regulatory authority could hold entities that dispose of such waste responsible for remedial treatment. On June 21, 2010, the EPA published its proposed coal combustion residuals regulations. The regulations are complex and contain various options for ash management that the EPA will select from to form the final version of the rule. We cannot determine the likely impact on our operations until the final version of the rule is known, which appears to be scheduled for some time in 2014. If ash becomes subject to regulations as a hazardous waste, implementation requirements could have a material impact on our financial position, results of operations or cash flows.

Manufactured Gas Processing

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

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

In March 2011, Nebraska Gas executed an Allocation, Indemnification and Access Agreement with the successor to the former operator of the Nebraska MGPs. Under this agreement, Nebraska Gas received $1.9 million from the successor to the operator for Nebraska Gas to remediate two sites in Nebraska (Blair and Plattsmouth). The successor is responsible for remediation activity at the two remaining sites in Nebraska (Columbus and Norfolk). Subsequent to this transaction, Nebraska Gas enrolled Blair and Plattsmouth in Nebraska’s Voluntary Cleanup Program. Site remediation was completed in September 2012. Both Nebraska sites will be required to monitor groundwater quality for a minimum two-year period to end in September 2014.

As of Dec. 31, 2013, we estimate a range of approximately $2.9 million to $6.3 million to remediate the MGP site in Council Bluffs, Iowa, of which we could be responsible for up to 25 percent of the costs. There are potentially other responsible parties relating to the site in Council Bluffs, Iowa; however, at this time no parties have been named nor have we determined the degree to which they are responsible. There are currently no regulatory requirements or deadlines for cleanup.

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 Dec. 31, 2013, we held varying interests in independent power plants operating in Wyoming and Colorado with a total net ownership of approximately 309 megawatts.

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 Dec. 31, 2013, 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
Gillette CT	Gas	Gillette, Wyo.	100.0%	40.0	2001
Wygen I	Coal	Gillette, Wyo.	76.5%	68.9	2003
Pueblo Airport Generation [1]	Gas	Pueblo, Colo.	100.0%	200.0	2012
				308.9	

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

Black Hills Wyoming - Gillette CT. The Gillette CT is a simple-cycle, gas-fired combustion turbine located at our Gillette, Wyo., energy complex. The facility's energy and capacity is sold to Cheyenne Light under a PPA that expires in August 2014. We sell excess power from our generating capacity into the wholesale power markets when it is available and economical. On May 6, 2013, Black Hills Wyoming entered into an agreement to sell the Gillette CT to the City of Gillette, Wyo. The sale is expected to close in August 2014 upon the expiration of the existing PPA with Cheyenne Light. This sale is subject to FERC approval and certain other requirements included in the contract.

Black Hills Wyoming - Wygen I. The Wygen I generation facility is a mine-mouth, coal-fired power plant with a total capacity of 90 megawatts located at our Gillette, Wyo., energy complex. We own 76.5 percent of the plant and MEAN owns the remaining 23.5 percent. We sell 60 megawatts of unit contingent capacity and energy from this plant to Cheyenne Light under a PPA that expires on Dec. 31, 2022. The PPA includes an option for Cheyenne Light to purchase Black Hills Wyoming's ownership interest in the Wygen I facility through 2019. The purchase price in the contract related to the option is $2.6 million per megawatt adjusted for capital additions and reduced by depreciation over 35 years starting Jan. 1, 2009 (approximately $5 million per year). The net book value of Wygen I at Dec. 31, 2013 was $79 million and if Cheyenne Light had exercised the purchase option at year-end 2013, the estimated purchase price would have been approximately $154 million. We expect Cheyenne Light to exercise its option to purchase sometime during the next several years. 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 megawatt combined-cycle gas-fired power generation plants located at a site shared with Colorado Electric. The plants commenced operation on Jan. 1, 2012, and the assets are accounted for as a capital lease under a 20-year PPA with Colorado Electric. Under the PPA with Colorado Electric, any excess capacity and energy shall be for the benefit of

Colorado Electric.

The following table summarizes megawatt-hours for our Power Generation segment:

Quantities Sold, Generated and Purchased (megawatt-hour)	2013	2012	2011
Sold			
Black Hills Colorado IPP	1,008,482	762,950	—
Black Hills Wyoming	556,307	541,687	556,577
Total Sold	1,564,789	1,304,637	556,577
Generated			
Black Hills Colorado IPP	1,008,482	762,950	—
Black Hills Wyoming	556,106	538,945	557,899
Total Generated	1,564,588	1,301,895	557,899
Purchased			
Black Hills Colorado IPP	—	—	—
Black Hills Wyoming	5,481	8,011	402
Total Purchased	5,481	8,011	402

Operating Agreements. Our Power Generation segment has 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.
Colorado IPP and Black Hills Wyoming also 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 for their share of the Wygen I generating facility for 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. However, state regulatory rules requiring utilities to competitively bid generation resources may provide opportunity for independent power producers in some regions.

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.

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 three EWGs: Gillette CT, Wygen I and 200 megawatts 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.

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 Gillette CT, 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 Gillette CT and Wygen I plants through 2043, 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 Gillette CT, 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, Wyo. The WRDC coal mine, which we acquired in 1956 from Homestake Gold Mining Company, is located in the Powder River Basin. The Powder River Basin contains one of the largest coal reserves in the United States. We produced approximately 4.3 million tons of coal in 2013.

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

In a basin characterized by thick coal seams, our overburden ratio, a comparison of the cubic yards of dirt removed to a ton of coal uncovered, had in recent years trended upwards. The overburden ratio decreased in the second half of 2012 when we relocated mining operations to an area of the mine with lower overburden. The overburden ratio has been reduced approximately 60 percent during 2013.

Mining rights to the coal are based on four federal leases and one state lease. The federal leases expire between Sept. 30, 2015, to March 31, 2021, and the state lease expires on Aug. 1, 2023. The duration of the leases vary; 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 percent and 9.0 percent, respectively, of the selling price of all coal. As of Dec. 31, 2013, we estimated our recoverable coal reserves to be approximately 213 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 40 years at the current expected production levels. Our recoverable coal reserve estimates are periodically updated to reflect past coal production and other geological and mining data. Changes in mining methods or the utilization of new technologies may increase or decrease the recovery basis for a coal seam. Our recoverable coal reserves include reserves that can be economically and legally extracted at the time of their determination. We use various assumptions in preparing our estimate of recoverable coal reserves. See Risk Factors under Coal Mining for further details.

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

- Black Hills Power for use at its Ben French, Neil Simpson I and Neil Simpson II plants. Effective Aug. 31, 2012, Black Hills Power suspended operations at the 25 megawatt Ben French plant and announced the retirement of the Ben French plant and the 21.8 megawatt Neil Simpson I plant effective March 21, 2014. We sold approximately 120,000 tons per year to Ben French when it was operable and sell approximately 130,000 tons of coal per year to Neil Simpson I;

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

- the 110 megawatt Wygen III power plant owned 52 percent by Black Hills Power, 25 percent by MDU and 23 percent 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 megawatt Wygen I power plant owned 76.5 percent by Black Hills Wyoming and 23.5 percent by MEAN to which we sell approximately 500,000 tons of coal each year. This contract expires June 30, 2038; and

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

Our Coal Mining segment sells coal to Black Hills Power and Cheyenne Light for all of their requirements under cost-based agreements that regulate earnings from these affiliate coal sales to a specified return on our coal mine's cost-depreciated investment base. The return is 4 percent above A-rated utility bonds, to be applied to our coal mining investment base as determined each year. 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 for unprocessed coal sold to PacifiCorp for its 80 percent interest in the Wyodak plant is determined by the coal supply agreement described above. The agreement includes price adjustments in 2014 and 2019, which essentially allow us to retain the full economic advantage of the mine's location adjacent to the plant. The price adjustments will be based on the market price of coal plus considerations for the avoided costs of rail transportation and a coal unloading facility which PacifiCorp would have to incur if it purchased coal from another mine.

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 4 percent with the base price being adjusted on a 5-year interval. The agreement stipulates that WRDC will supply coal to the 90 megawatt Wygen 1 plant through June 30, 2038.

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

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

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

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

Ash is the inorganic residue remaining after the combustion of coal. Ash from our Wyoming power plants, as well as PacifiCorp's Wyodak power plant, is disposed of in the mine and is utilized for backfill to meet permitted post-mining contour requirements. The EPA has proposed national disposal regulations that include multiple options, one of which regulates coal ash as a hazardous waste. A final rule is expected in 2014. While the proposed combustion residuals regulations do not address mine backfill, it is widely expected that the U.S. Office of Surface Mining will collaborate with the EPA to address mine backfill in the near future. If the ash is regulated as a hazardous waste, the implementation requirements of more stringent management, handling, storage, transportation and disposal requirements will likely increase the cost of ash disposal for the power plants and/or increase backfill costs for the coal mine.

Mine Reclamation. Reclamation is required during production and after mining has been completed. Under applicable law, we must submit applications to, and receive approval from, the WDEQ for any mining and reclamation plan that provides for orderly mining, reclamation, and restoration of the WRDC mine. We have approved mining permits and are in compliance with other permitting programs administered by various regulatory agencies. The WRDC coal mine is permitted to operate under a five year mining permit issued by the State of Wyoming. The current permit expires in 2016. Based on extensive reclamation studies, we have accrued approximately $21 million for reclamation costs as of Dec. 31, 2013. Mining regulatory requirements continue to increase, which impose additional cost on the mining process.

Oil and Gas Segment

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

As of Dec. 31, 2013, the principal assets of our Oil and Gas segment included: (i) operating interests in crude oil and natural gas properties, including properties in the San Juan Basin (with holdings primarily on the tribal lands of the Jicarilla Apache Nation in New Mexico and Southern Ute Nation in Colorado), the Powder River Basin (Wyoming) and the Piceance Basin (Colorado); (ii) non-operated interests in crude oil and natural gas properties including wells located in the Williston (Bakken Shale in North Dakota), Wind River (Wyoming), Bear Paw Uplift (Montana), Arkoma (Oklahoma), Anadarko (Texas and Kansas) and Sacramento (California) basins; and (iii) a 44.7 percent 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 the majority of the facility's throughput. We also own natural gas gathering, compression and treating facilities serving the operated San Juan and Piceance Basin properties and working interests in similar facilities serving our non-operated Montana and Wyoming properties.

At Dec. 31, 2013, we had total reserves of approximately 87 Bcfe, of which natural gas comprised 73 percent and crude oil comprised 27 percent. The majority of our reserves are located in select crude oil and natural gas producing basins in the Rocky Mountain region. Approximately 31 percent of our reserves are located in the San Juan Basin of northwestern New Mexico, primarily in the East Blanco Field of Rio Arriba County; 30 percent are located in the Powder River Basin of Wyoming, primarily in the Finn-Shurley Field of Weston and Niobrara counties; and 25 percent are located in the Piceance Basin of western Colorado, primarily in Mesa county.

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

Summary Oil and Gas Reserve Data

The summary information presented for our estimated proved developed and undeveloped crude oil and natural gas reserves and the 10 percent 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 and natural gas are reported separately and then combined for a total MMcfe (where oil in Mbbl is converted to an MMcfe basis by multiplying Mbbl by six).

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

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

CG&A is a Texas Registered Engineering Firm. Our primary contact at CG&A is Mr. Zane Meekins. Mr. Meekins has been practicing consulting petroleum engineering since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas and has over 25 years of practical experience in petroleum engineering and over 23 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1987 with a Bachelor of Science in Petroleum Engineering. Mr. Meekins meets or exceeds the education, training and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

BHEP’s Manager of Planning and Analysis is the technical person primarily responsible for overseeing our third party reserve estimates. He has over 33 years of exploration and production industry experience as a geologist and financial analyst. He has over 23 years of experience working closely with internal and third party qualified reserve estimators in major and mid-sized oil and gas companies. He holds a Bachelor of Science degree in Geology and a Masters in Business Administration.

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 Dec. 31, 2013, 2012 and 2011:

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

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

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

Proved Reserves	Dec. 31, 2011					
	Total	Piceance	San Juan	Williston	Powder River	Other
Developed Producing -						
Natural Gas (MMcf)	68,691	14,624	35,609	1,608	8,747	8,103
Oil (Mbbl)	4,517	—	12	1,012	3,472	21
Total Developed Producing (MMcfe)	95,793	14,624	35,681	7,680	29,579	8,229
Developed Non-Producing -						
Natural Gas (MMcf)	3,176	974	854	346	179	823
Oil (Mbbl)	313	—	—	235	77	1
Total Developed Non-Producing (MMcfe)	5,054	974	854	1,756	641	829
Undeveloped -						
Natural Gas (MMcf)	24,031	12,765	8,132	2,102	—	1,032
Oil (Mbbl)	1,394	—	—	1,394	—	—
Total Undeveloped (MMcfe)	32,395	12,765	8,132	10,466	—	1,032
Total MMcfe	133,242	28,363	44,667	19,902	30,220	10,090

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 Dec. 31, 2013, 2012 and 2011:

Crude Oil	Dec. 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	Dec. 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

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

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

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

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

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

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

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

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

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

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

Crude Oil	Dec. 31, 2011					
(in Mbbl)	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	5,940	—	11	2,014	3,891	24
Production	(452)	—	(2)	(182)	(264)	(4)
Additions - acquisitions	(84)	—	—	—	(84)	—
Additions - extensions and discoveries	927	—	—	927	—	—
Revisions to previous estimates	(108)	—	3	(118)	6	1
Balance at end of year	6,223	—	12	2,641	3,549	21

Natural Gas	Dec. 31, 2011					
(in MMcf)	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	95,456	33,252	36,901	2,499	10,180	12,624
Production	(8,526)	(1,077)	(5,063)	(173)	(516)	(1,697)
Additions - acquisitions	—	—	—	—	—	—
Additions - extensions and discoveries	29,664	16,797	11,109	1,460	—	298
Revisions to previous estimates	(20,690)	(20,609)	1,648	270	(738)	(1,261)
Balance at end of year	95,904	28,363	44,595	4,056	8,926	9,964

	Dec. 31, 2011					
Total MMcfe [(a)]	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	131,096	33,252	36,967	14,583	33,526	12,768
Production	(11,238)	(1,077)	(5,075)	(1,265)	(2,100)	(1,721)
Additions - acquisitions	(504)	—	—	—	(504)	—
Additions - extensions and discoveries	35,226	16,797	11,109	7,022	—	298
Revisions to previous estimates [(b)]	(21,338)	(20,609)	1,666	(438)	(702)	(1,255)
Balance at end of year	133,242	28,363	44,667	19,902	30,220	10,090

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

(b) Revisions to previous estimates for 2011 were primarily due to the SEC requirement that PUD locations must be developed within five years or must be removed from proved undeveloped reserves. Included in the total revisions are (23,647) MMcfe for dropped PUD locations due to five year aging of reserves which was offset by positive performance revisions of 2,315 MMcfe in various basins. Revisions due to cost and commodity pricing were less than one percent of total reserve quantities.

Production Volumes

		Year ended Dec. 31, 2013			
Location (Basin)	Field	Oil (in Bbl)	Natural Gas (Mcfe)	NGLs (Gallons)	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	393,892	1,407,555
Powder River	Finn Shurley	186,780	361,135	2,811,443	1,883,450
Powder River	All others	18,833	4,661	—	117,659
Williston	Bakken	125,889	163,805	217,641	950,231
All other properties	Various	2,173	1,271,715	281,662	1,324,990

Total Volume	336,140	6,983,104	3,704,638	9,529,178

		Year ended Dec. 31, 2012			
Location (Basin)	Field	Oil (in Bbl)	Natural Gas (Mcfe)	NGLs (Gallons)	Total (Mcfe)
San Juan	East Blanco	1,423	3,584,746	—	3,593,284
San Juan	All others	—	1,338,843	—	1,338,843
Piceance	Piceance	—	1,716,588	244,339	1,751,494
Powder River	Finn Shurley	202,698	441,165	2,742,039	2,049,073
Powder River	All others	15,757	4,667	—	99,209
Williston(a)	Bakken	337,579	404,466	159,543	2,452,732
All other properties	Various	2,514	1,195,716	339,593	1,259,313
Total Volume		559,971	8,686,191	3,485,514	12,543,948

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

		Year ended Dec. 31, 2011			
Location (Basin)	Field	Oil (in Bbl)	Natural Gas (Mcfe)	NGLs (Gallons)	Total (Mcfe)
San Juan	East Blanco	1,746	4,225,027	—	4,235,503
San Juan	All others	—	837,635	—	837,635
Piceance	Piceance	—	1,077,040	240,667	1,111,421
Powder River	Finn Shurley	248,089	512,100	2,983,700	2,426,877
Powder River	All others	16,269	4,230	—	101,844
Williston	Bakken	181,580	167,367	39,079	1,262,429
All other properties	Various	4,139	1,703,021	411,368	1,786,622
Total Volume		451,823	8,526,420	3,674,814	11,762,331

Other Information

	As of Dec. 31, 2013	As of Dec. 31, 2012
Proved developed reserves as a percentage of total proved reserves on an MMcfe basis	95 %	98 %
Proved undeveloped reserves as a percentage of total proved reserves on an MMcfe basis (a)	5 %	2 %
Present value of estimated future net revenues, before tax, discounted at 10 percent (in thousands)	$184,372	$151,255

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

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

	Dec. 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

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

	Dec. 31, 2011					
	Total	Piceance	San Juan	Williston	Powder River	Other
Gas per Mcf	$3.59	$3.73	$3.37	$3.07	$4.36	$3.83
Oil per Bbl	$88.49	$—	$80.80	$85.05	$91.09	$84.61

Drilling Activity

In 2013, we participated in drilling 38 gross (5 net) development and exploratory wells, with a net well success rate of 95 percent. 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 Dec. 31,	2013		2012		2011	
Net Development Wells	Productive	Dry	Productive	Dry	Productive	Dry
Piceance	—	—	—	—	—	—
San Juan	—	—	—	—	1.00	—
Williston	1.00	—	1.80	—	1.73	—
Powder River	0.19	—	0.74	0.19	—	—
Other	—	—	—	—	3.59	—
Total net development wells	1.19	—	2.54	0.19	6.32	—

Year ended Dec. 31,	2013		2012		2011	
Net Exploratory Wells	Productive	Dry	Productive	Dry	Productive	Dry
Piceance	1.00	—	0.86	—	0.99	—
San Juan	—	—	—	—	0.80	—
Williston	—	—	—	—	—	—
Powder River	—	1.80	—	—	—	—
Other	0.80	—	—	—	0.25	1.70
Total net exploratory wells	1.80	1.80	0.86	—	2.04	1.70

As of Dec. 31, 2013, we were participating in the drilling of 10 gross (3.18 net) wells, which had been commenced but not yet completed.

Recompletion Activity

Recompletion activities for the years ended Dec. 31, 2013, 2012 and 2011 were insignificant to our overall oil and gas operations.

Productive Wells

The following table summarizes our gross and net productive wells at Dec. 31, 2013, 2012 and 2011:

	Dec. 31, 2013					
	Total	Piceance	San Juan	Williston	Powder River	Other
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

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

	Dec. 31, 2011					
	Total	Piceance	San Juan	Williston	Powder River	Other
Gross Productive:						
Crude Oil	462	—	2	56	398	6
Natural Gas	757	66	218	—	1	472
Total	1,219	66	220	56	399	478
Net Productive:						
Crude Oil	299.10	—	1.91	3.97	292.45	0.77
Natural Gas	322.57	53.63	201.40	—	0.06	67.48
Total	621.67	53.63	203.31	3.97	292.51	68.25

Acreage

The following table summarizes our undeveloped, developed and total acreage by location as of Dec. 31, 2013:

	Undeveloped		Developed		Total	
	Gross	Net [(a)]	Gross	Net	Gross	Net
Piceance	66,221	50,645	33,518	29,280	99,739	79,925
San Juan	40,837	39,433	24,902	23,199	65,739	62,632
Williston [(b)]	1,294	166	11,049	1,727	12,343	1,893
Powder River	129,355	74,498	30,932	16,045	160,287	90,543
Bear Paw Uplift (MT)	136,123	26,498	100,209	19,182	236,332	45,680
Other	69,256	44,277	26,830	4,748	96,086	49,025
Total	443,086	235,517	227,440	94,181	670,526	329,698

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(a) Approximately 10 percent (87,689 gross and 23,648 net acres), 19 percent (87,748 gross and 44,136 net acres) and 15 percent (46,458 gross and 34,374 net acres) of our undeveloped acreage could expire in 2014, 2015 and 2016, respectively, if production is not established on the leases or further action is not taken to extend the associated lease terms. Decisions on extending leases are based on expected exploration or development potential under the prevailing economic conditions.

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

Competition. The oil and gas industry is highly competitive. We compete with a substantial number of companies ranging from those that have greater financial resources, personnel, facilities and in some cases technical expertise, to a multitude of smaller, aggressive new start-up companies. Many of these companies explore for, 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 for drilling and development activity, locating and acquiring producing oil and gas properties, locating and obtaining sufficient drilling rig and contractor services, receiving economical costs for drilling and other oil and gas services, and securing purchasers and transportation for the oil and natural gas we produce.

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 contract for natural gas production from our properties in the Piceance Basin in Colorado, under which we will pay a gathering fee per Mcf. The contract requires us to deliver a minimum of 20,000 Mcf per day. The gatherer is in the process of building the necessary infrastructure to handle the committed volumes. The agreement becomes effective when the infrastructure is placed in commercial service, which is anticipated in the first quarter of 2014. We believe that our reserves dedicated to the gathering system, and the projected volumes are adequate to satisfy our delivery commitments under this agreement.

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

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

One or more of these factors may increase our cost of doing business on tribal lands and impact the expansion and viability of our gas, oil and gathering operations on such lands.

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

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

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

Hydraulic fracturing is an essential and common practice, which has been used extensively for decades in the oil and gas industry to enhance the production of natural gas and/or oil from dense subsurface rock formations. We routinely apply hydraulic fracturing techniques on our crude oil and natural gas properties. Our hydraulic fracturing mixture is 90 percent water, 9.5 percent sand and 0.5 percent of certain chemical additives to fracture the hydrocarbon-bearing rock formation to enhance flow of hydrocarbons into the well-bore. Chemicals used in the fracturing process are publicly posted as required by state regulations. The process is regulated by state oil and natural gas commissions; however, the EPA does assert federal regulatory authority over certain hydraulic fracturing activities when diesel comprises part of the fracturing fluid. In addition, several agencies of the federal government including the EPA and the BLM are conducting studies of the fracturing stimulation process, which may result in additional regulations. In the event federal, state, local or municipal legal restrictions are adopted in areas where we are conducting, or plan to conduct operations, we may incur additional costs to comply with such regulations, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from utilizing fracture stimulation which may effectively preclude the drilling of wells. In May 2013, the U.S. Department of the Interior re-proposed rules regulating the use of hydraulic fracturing on Federal and Indian Lands. Final action on these proposed rules is expected in 2014. All of these new or proposed regulations are expected to result in additional costs to our operations.

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

In 2013, we participated in the State of Colorado's stakeholder process to incorporate EPA Quad O requirements into state regulation. State regulations are expected to be final in early 2014. New Mexico incorporated Quad O regulations, effective Dec. 19, 2013. Wyoming incorporated Quad O regulations effective Jan. 3, 2014.

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

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

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

Greenhouse Gas Regulations. The EPA promulgated an amendment to its GHG reporting requirements in November 2010, adding Petroleum and Natural Gas Systems to the mandatory annual reporting requirements. Initial data gathering commenced on Jan. 1, 2011, with the first annual report submitted to the EPA in 2012. 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.

Other Properties

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

- In Rapid City, S.D., 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, Colo., 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, Wyo., we own a business office with approximately 14,300 square feet, and a service center and garage with an aggregate of approximately 24,400 square feet.

- In Papillion, Nebr., 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 236,500 square feet utilized by our Gas Utilities.

- In South Dakota, Wyoming, Colorado and Montana we own various office, service center, storage, shop and warehouse space totaling approximately 97,000 square feet utilized by our Electric Utilities and our Coal Mining segments.

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

- Approximately 8,800 square feet for an operations and customer call center in Rapid City, S.D.;
- Approximately 37,600 square feet for a customer call center in Lincoln, Nebr.;
- Approximately 48,400 square feet of office space in Denver, Colo., of which we sublease approximately 10,100 square feet to a third party;
- Approximately 108,600 square feet of various office, service center and warehouse space leased by the Gas Utilities;
- Approximately 2,000 square feet of various office, service center and warehouse space leased by the Electric Utilities; and
- Other offices and warehouse facilities located within our service areas.

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

Employees

At Dec. 31, 2013, we had 1,948 full-time employees. Approximately 31 percent of our employees are represented by a collective bargaining agreement. We have not experienced any labor stoppages in recent years. At Dec. 31, 2013, approximately 27 percent 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	391
Utilities	1,412
Non-regulated Energy	145
Total	1,948

At Dec. 31, 2013, 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	144	IBEW Local 1250	March 31, 2017
Cheyenne Light	52	IBEW Local 111	June 30, 2016
Colorado Electric	113	IBEW Local 667	April 15, 2015
Iowa Gas	123	IBEW Local 204	July 31, 2015
Kansas Gas	20	Communications Workers of America, AFL-CIO Local 6407	Dec. 31, 2014
Nebraska Gas	161	IBEW Local 244	March 13, 2014
Total	613		

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 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 retain management or other key personnel;
- Our inability to negotiate acceptable acquisition, construction, fuel supply, power sales or other material agreements;
- The trend of utilities building their own generation or looking for developers to develop and build projects for sale to utilities under turnkey arrangements;
- Reduced growth in the demand for utility services in the markets we serve;
- Changes in federal, state, local or tribal laws and regulations, particularly those which would make it more difficult or costly to fully develop our coal reserves, our oil and gas reserves and our generation capacity;
- Fuel prices or fuel supply constraints;
- Pipeline capacity and transmission constraints;
- Competition within our industry and with producers of competing energy sources; and
- Changes in tax rates and policies.

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

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

- Operational limitations imposed by environmental and other regulatory requirements;
- Interruptions to supply of fuel and other commodities used in generation and distribution. The Utilities Group purchases fuel from a number of suppliers. Our results of operations could be negatively impacted by disruptions in the delivery of fuel due to various factors, including but not limited to, transportation delays, labor relations, weather, and environmental regulations, which could limit the Utilities Group's ability to operate their facilities;
- Breakdown or failure of equipment or processes, including those operated by PacifiCorp at the Wyodak plant;
- Inability to recruit and retain skilled technical labor;
- Disrupted transmission and distribution. We depend on transmission and distribution facilities, including those operated by unaffiliated parties, to deliver the electricity and gas that we sell to our retail and wholesale customers. If transmission is interrupted, our ability to sell or deliver product and satisfy our contractual obligations may be hindered;
- Operating hazards such as leaks, mechanical problems and accidents, including explosions, affecting our natural gas distribution system which could impact public safety, reliability and customer confidence;
- Electricity is dangerous for employees and the general public should they come in contact with power lines or electrical equipment. Natural conditions and other disasters such as wind, lightning and winter storms can cause wildfires, pole failures and associated property damage and outages. For example, as described in more detail under "Legal Proceedings," a fire investigator concluded that a forest and grassland fire in the western Black Hills of Wyoming and South Dakota in 2012 was caused by the failure of a transmission structure owned, operated and maintained by Black Hills Power, and claims have been made against us related to the fire;
- Disruption in the functioning of our information technology and network infrastructure which are vulnerable to disability, failures and unauthorized access. If our information technology systems were to fail and we were unable to recover in a timely manner, we would be unable to fulfill critical business functions; and
- Labor relations. Approximately 31 percent of our employees are represented by a total of six collective bargaining agreements.

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

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

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

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

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

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

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

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

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

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

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

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 are 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 also 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 is near all-time 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, cyber-attacks, 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, as well as cyber-attacks 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.

We operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. Despite our implementation of security measures, all of our technology systems are vulnerable to disability, failures or unauthorized access, including cyber-attacks. If our technology systems were to fail or be breached 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.

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.

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

We had approximately $353 million of goodwill on our consolidated balance sheets as of Dec. 31, 2013. A substantial portion of the goodwill is related to the Aquila Transaction. If we make changes in our business strategy or if market or other conditions adversely affect operations in any of our businesses, we may be forced to record a non-cash impairment charge, which would reduce our reported assets, net income and shareholders' equity. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. If the testing performed indicates that impairment has occurred, we are required to record an impairment charge for the difference between the carrying value of the goodwill and the implied fair value of the goodwill in the period the determination is made. The testing of goodwill for impairment requires us to make significant estimates about our future performance and cash flows, as well as other assumptions. These estimates can be affected by numerous factors, including: future business operating performance; changes in economic conditions, and interest rates, regulatory, industry or market conditions, changes in business operations, changes in competition or changes in technologies. Any changes in key assumptions, or actual performance compared with key assumptions, about our business and its future prospects could affect the fair value of one or more business segments, which may result in an impairment charge.

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

Municipal governments within our utility service territories possess the power of condemnation and could establish a municipal utility within a portion of our current service territories by limiting or denying franchise privileges for our operations, and exercising powers of condemnation over all or part of our utility assets within municipal boundaries.

Although condemnation is a process that is subject to constitutional protections requiring just and fair compensation, as with any judicial procedure, the outcome is uncertain. If a municipality sought to pursue this course of action, we cannot assure that we would secure adequate recovery of our investment in assets subject to condemnation.

Power Generation

Our ability to successfully complete the sale of CTII to the City of Gillette and execute the purchase option for the sale of Wygen I to Cheyenne Light Fuel & Power could adversely affect our Power Generation segment. The inability to obtain power sales contracts at reasonable rates to fully utilize these assets subsequent to the expiration of long-term contracts could affect our results of operations, financial position and liquidity.
Black Hills Wyoming entered into an agreement to sell its 40 megawatt CTII to the City of Gillette in August 2014 upon expiration of an existing power sales agreement under which Black Hills Power sells the output of the CTII to Cheyenne Light. This sale is subject to FERC approval and certain other requirements included in the contract.
Black Hills Wyoming has a power sales agreement with Cheyenne Light which expires in December 2022. This power sales agreement includes an option for Cheyenne Light to purchase Black Hills Wyoming's ownership interest in the Wygen I facility between 2013 and 2019. This purchase by Cheyenne Light would be subject to WPSC approval in order to obtain regulatory treatment.

Coal Mining

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

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

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

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

Oil and Gas

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

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

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

Hydraulic fracturing is an essential and common practice in the oil and gas industry used extensively for decades to stimulate production of natural gas and/or oil from dense subsurface rock formations. We routinely apply hydraulic fracturing techniques on our crude oil and natural gas properties. Hydraulic fracturing involves using mostly water, sand, and a small amount of certain chemicals to fracture the hydrocarbon-bearing rock formation to enhance flow of hydrocarbons into the well-bore. The process is typically regulated by state crude oil and natural gas commissions; however, the EPA does assert federal regulatory authority over certain hydraulic fracturing activities when diesel comprises part of the fracturing fluid. In addition several agencies of the federal government including the EPA and the BLM are conducting studies of the fracturing stimulation process which may result in additional regulations. In May 2013, the U.S. Department of the Interior re-proposed rules regulating the use of hydraulic fracturing on Federal and Indian Lands, with final action expected in 2014. 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. Any excess of the net book value, less deferred income taxes, is generally written off as an expense.

We recorded a non-cash impairment charge in the second quarter of 2012 due to the full cost ceiling limitations. We may have to record additional non-cash impairment charges in the future if commodity prices drive the SEC-defined prices below levels that precipitated the 2012 impairment. See Note 12 to the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

FINANCING RISKS

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

Our issuer credit rating is Baa2 (Positive outlook) by Moody’s; BBB (Stable outlook) by S&P; and BBB (Positive 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 downgrade 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 rely on cash distributions from our subsidiaries to make and maintain dividends and debt payments. Our subsidiaries may not be allowed or may be unable to make dividend payments or loan funds to us, which could adversely affect our ability to meet our financial obligations or pay dividends to our shareholders.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The IRS has challenged our position with respect to the like-kind exchange. As stated in a revised Notice of Proposed Adjustment received from the IRS in April 2013, their position is to disallow a significant portion of the gain deferred as reported on our originally filed 2008 tax return. We disagree with such a position and will pursue all available IRS and/or legal channels to challenge the proposed adjustment. 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 tax payable would be approximately $125 million. However, we would be entitled to a 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 $23 million before income tax effect.

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

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

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

ENVIRONMENTAL RISKS

Federal and state laws concerning greenhouse gas regulations and air emissions may materially increase our generation and production costs and could render some of our generating units uneconomical to operate and maintain.
We own and operate regulated and non-regulated fossil-fuel generating plants in South Dakota, Wyoming, and Colorado. Recent developments under federal and state laws and regulations governing air emissions from fossil-fuel generating plants will likely result in more stringent emission limitations, which could have a material impact on our costs of operations. Various pending or final state and EPA regulations that will impact our facilities are also discussed in Item 1 of this Annual Report on Form 10-K under the caption “Environmental Matters.”
On May 20, 2011, with amendments on Dec. 21, 2012, the EPA’s Industrial and Commercial Boiler regulations became effective, which provide for hazardous air pollutant-related emission limits and monitoring requirements. The compliance deadline for this rule is March 21, 2014. Engineering evaluations were completed and confirmed the significant impact on our Neil Simpson I, Osage and Ben French facilities. These units will be retired on or before the March 21, 2014 compliance deadline. Although we will seek recovery for the remaining net book values of these plants and prudent decommissioning costs of these units, we cannot be assured of this recovery.

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

The GHG Tailoring Rule, implementing regulations of GHG for permitting purposes, became effective in June 2010. This rule will impact us in the event of a major modification at an existing facility or in the event of a new major source as defined by EPA regulations. Upon renewal of operating permits for existing facilities monitoring and reporting requirements will be implemented. New projects or major modifications to existing projects will result in a Best Available Control Technology review that could impose more stringent emissions control practices and technologies. The EPA's GHG New Source Performance Standard for new steam electric generating units was re-proposed in September 2013 and is expected to be final in the spring of 2014. As proposed, it effectively prohibits new coal fired units until carbon capture and sequestration becomes technically and economically feasible. It also effectively prohibits simple cycle natural gas combustion turbines from generating more than one-third of their capacity, averaged over a three year period. In 2014, we expect the EPA, to propose regulations for GHG emissions from existing steam electric generating units. This rule could have a significant impact on our coal and natural gas generating fleet.
Due to uncertainty as to the final outcome of federal climate change legislation, or regulatory changes under the Clean Air Act, we cannot definitively estimate the effect of GHG legislation or regulation on our results of operations, cash flows or financial position. The impact of GHG legislation or regulation on our company will depend upon many factors, including but not limited to the timing of implementation, the GHG sources that are regulated, the overall GHG emissions cap level, and the availability of technologies to control or reduce GHG emissions. If a "cap and trade" structure is implemented, the impact will depend on the degree to which offsets are allowed, the allocation of emission allowances to specific sources, and the effect of carbon regulation on natural gas and coal prices.
New or more stringent regulations or other energy efficiency requirements could require us to incur significant additional costs relating to, among other things, the installation of additional emission control equipment, the acceleration of capital expenditures, the purchase of additional emissions allowances or offsets, the acquisition or development of additional energy supply from renewable resources, and the closure of certain generating facilities. To the extent our regulated fossil-fuel generating plants are included in rate base we will attempt to recover costs associated with complying with emission standards or other requirements. We will also attempt to recover the emission compliance costs of our non-regulated fossil-fuel generating plants from utility and other purchasers of the power generated by those non-regulated power plants. Any unrecovered costs could have a material impact on our results of operations and financial condition. In addition, future changes in environmental regulations governing air emissions could render some of our power generating units more expensive or uneconomical to operate and maintain.
The failure to achieve or maintain compliance with existing or future governmental laws, regulations or requirements could adversely affect our results of operations, financial position or liquidity. Additionally, the potentially high cost of complying with such requirements or addressing environmental liabilities could also adversely affect our results of operations, financial position or liquidity.

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

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

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

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

Proposed reductions in emissions of mercury, sulfur dioxides, nitrogen oxides, particulate matter, or greenhouse gases may require the installation of costly emission control technology or the implementation of other measures. For example, in order to meet the federal Clean Air Act limits for SO_2 emission from power plants, coal users may need to install scrubbers, use SO_2 emission allowances (some of which they may purchase), blend high-sulfur coal with low-sulfur coal or switch to other fuels. Reductions in mercury emission required by certain states and the EPA will likely require some power plants to install new equipment, at substantial cost, or discourage the use of certain coals containing higher levels of mercury. EPA is scheduled to propose GHG regulations for existing sources in June 2014 which are expected to contain state-specific goals for overall emission reductions. These rules could have a significant impact on our coal fired generating assets and on our coal mine. Existing or proposed legislation focusing on emissions enacted by the United States or individual states could make coal a less attractive fuel alternative for our customers and could impose a tax or fee on the producer of the coal. If our customers decrease the volume of coal they purchase from us or switch to alternative fuels as a result of existing or future environmental regulations aimed at reducing emissions, our operations and financial results could be adversely impacted.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

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

ITEM 4. SPECIALIZED 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 Dec. 31, 2013, we had 4,324 common shareholders of record and approximately 31,000 beneficial owners, representing all 50 states, the District of Columbia and 9 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 Jan. 30, 2014 meeting, our Board of Directors declared a quarterly dividend of $0.39 per share, equivalent to an annual dividend of $1.56 per share, marking 2014 as the 44th 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 Dec. 31, 2013	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$0.380	$0.380	$0.380	$0.380
Common stock prices				
High	$44.32	$50.53	$55.09	$54.83
Low	$36.89	$43.19	$46.62	$47.00

Year ended Dec. 31, 2012	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$0.370	$0.370	$0.370	$0.370
Common stock prices				
High	$35.82	$34.31	$36.28	$37.00
Low	$32.18	$31.32	$30.29	$33.51

UNREGISTERED SECURITIES ISSUED

There were no unregistered securities sold during 2013.

ISSUER PURCHASES OF EQUITY SECURITIES

There were no equity securities acquired for the three months ended Dec. 31, 2013.

ITEM 6. SELECTED FINANCIAL DATA

Years Ended Dec. 31, (dollars in thousands, except per share amounts)	2013		2012		2011		2010		2009	
Total Assets	$3,875,178		$3,729,471		$4,127,083		$3,711,509		$3,317,698	
Property, Plant and Equipment										
Total property, plant and equipment	$4,259,445		$3,930,772		$3,724,016		$3,353,509		$2,973,398	
Accumulated depreciation and depletion	$(1,269,148	)	$(1,188,023	)	$(934,441	)	$(861,775	)	$(812,961	)
Capital Expenditures	$379,534		$347,980		$431,707		$496,990		$347,819	
Capitalization										
Current maturities of long-term debt	$—		$103,973		$2,473		$5,181		$35,245	
Notes payable	82,500		277,000		345,000		249,000		164,500	
Long-term debt, net of current maturities	1,396,948		938,877		1,280,409		1,186,050		1,015,912	
Common stock equity	1,307,748		1,232,509		1,209,336		1,100,270		1,084,837	
Total capitalization	$2,787,196		$2,552,359		$2,837,218		$2,540,501		$2,300,494	
Capitalization Ratios										
Short-term debt, including current maturities	3	%	15	%	12	%	10	%	9	%
Long-term debt, net of current maturities	50	%	37	%	45	%	47	%	44	%
Common stock equity	47	%	48	%	43	%	43	%	47	%
Total	100	%	100	%	100	%	100	%	100	%
Total Operating Revenues	$1,275,852		$1,173,884		$1,272,188		$1,219,691		$1,198,712	
Net Income Available for Common Stock										
Utilities	$84,841		$79,588		$81,860		$74,563		$57,071	
Non-regulated Energy	18,403	(2)	24,725	(2)	866		10,189		1,581	(3)
Corporate and intersegment eliminations	12,602	(1)	(15,808	) (1)	(42,361	) (1)	(21,611	) (1)	18,617	(1)
Income (loss) from continuing operations	115,846		88,505		40,365		63,141		77,269	
Income (loss) from discontinued operations, net	(884	)	(6,977	)	9,365		5,544		4,286	

of tax [4]					
Net income available for common stock	$114,962	$81,528	$49,730	$68,685	$81,555

SELECTED FINANCIAL DATA continued

Years Ended Dec. 31, (dollars in thousands, except per share amounts)	2013	2012	2011	2010	2009
Dividends Paid on Common Stock	$67,587	$65,262	$59,202	$56,467	$55,151
Common Stock Data[5] (in thousands)					
Shares outstanding, average basic	44,163	43,820	39,864	38,916	38,614
Shares outstanding, average diluted	44,419	44,073	40,081	39,091	38,684
Shares outstanding, end of year	44,499	44,206	43,925	39,269	38,969
Earnings (Loss) Per Share of Common Stock (in dollars) [6]					
Basic earnings (loss) per average share -					
Continuing operations	$2.62	$2.02	$1.01	$1.62	$2.00
Discontinued operations	(0.02)	(0.16)	0.24	0.14	0.11
Total	$2.60	$1.86	$1.25	$1.76	$2.11
Diluted earnings (loss) per average share -					
Continuing operations	$2.61	$2.01	$1.01	$1.62	$2.00
Discontinued operations	(0.02)	(0.16)	0.23	0.14	0.11
Total	$2.59	$1.85	$1.24	$1.76	$2.11
Dividends Declared per Share	$1.52	$1.48	$1.46	$1.44	$1.42
Book Value Per Share, End of Year	$29.35	$27.84	$27.55	$28.02	$27.84
Return on Average Common Stock Equity (full year)	8.8 %	6.7 %	4.3 %	6.3 %	7.6 %

SELECTED FINANCIAL DATA continued

Years ended Dec. 31,	2013	2012	2011	2010	2009
Operating Statistics:					
Generating capacity (MW):					
Electric Utilities (owned generation)	790	859	865	687	630
Electric Utilities (purchased capacity)	150	150	450	440	430
Power Generation (owned generation)	309	309	309	120	120
Total generating capacity	1,249	1,318	1,624	1,247	1,180
Electric Utilities:					
Megawatt-hours sold:					
Retail electric	4,642,254	4,598,080	4,590,800	4,532,191	4,403,459
Contracted wholesale	357,193	340,036	349,520	468,782	645,297
Wholesale off-system	1,456,762	1,652,949	1,788,005	1,749,524	1,692,191
Total Megawatt-hours sold	6,456,209	6,591,065	6,728,325	6,750,497	6,740,947
Gas Utilities: (6)					
Gas sold (Dth)	59,097,493	47,358,505	55,764,154	55,265,630	56,671,438
Transport volumes (Dth)	63,821,546	60,480,822	59,216,132	59,879,450	55,104,284
Power Generation Segment:					
Megawatt-Hours Sold	1,564,789	1,304,637	556,577	519,057	546,403
Megawatt-Hours Purchased	5,481	8,011	402	27,734	—
Oil and Gas Segment:					
Oil and gas production sold (MMcfe)	9,529	12,544	11,762	11,300	12,463
Oil and gas reserves (MMcfe) (2)	86,713	80,683	133,242	131,096	119,304
Coal Mining Segment:					
Tons of coal sold (thousands of tons) (7)	4,285	4,246	5,692	5,931	5,955
Coal reserves (thousands of tons)	212,595	232,265	256,170	261,860	268,000

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(1) 2011 and 2010 include a $27 million and $9.9 million non-cash after-tax unrealized mark-to-market loss, respectively, related to certain interest rate swaps; while 2013, 2012 and 2009 include a $20 million, $1.2 million and a $36 million non-cash after-tax unrealized mark-to-market gain, respectively, related to certain interest rate swaps. 2013 also includes $7.6 million after-tax expense for a make-whole premium, write-off of deferred financing costs relating to the early redemption of our $250 million notes and interest expense on new debt, while 2012 includes an after-tax make-whole provision of $4.6 million for early redemption of our $225 million notes.

(2) 2013 includes $6.6 million after-tax expense relating to the settlement of interest rate swaps in conjunction with the prepayment of Black Hills Wyoming's project financing and write-off of deferred financing costs. 2012 includes a non-cash after-tax ceiling test impairment charge to our crude oil and natural gas properties of $17 million offset by an after-tax gain on sale of $19 million related to our Williston Basin assets. Reserves reflect the sale of the Williston Basin assets. (See Notes 12 and 21 of the Notes to the Consolidated Financial Statements of this Annual Report on Form 10-K.)

(3) 2009 Net income includes a $28 million non-cash after-tax ceiling test impairment charge to our crude oil and natural gas properties and a $17 million after-tax gain on sale of a 23.5 percent ownership interest in Wygen I.

(4) Discontinued operations include post-closing adjustments and operations relating to our Energy Marketing segment in 2013, 2012, 2011, 2010 and 2009, and the assets sold in the IPP Transaction for 2009.

(5)

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

(6) Excludes Cheyenne Light.

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

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

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

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

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

Overview: We are a customer-focused integrated energy company. Our focus on customers - whether they are utility customers or non-regulated energy customers - provides opportunities to expand our business by constructing additional rate base assets to serve our utility customers and expanding our non-regulated energy holdings to provide additional products and services to our wholesale customers.

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

Our objective is to be best-in-class relative to certain operational performance metrics, such as safety, availability, reliability, efficiency, customer service and cost management. Our notable operational performance metrics for 2013 include:

- Our power generation fleet achieved 1st Quartile Reliability ranking with less than 65 minutes (SAIDI) in 2013 compared to industry averages[^^] ([^^]2012 Edison Electric Institute, less than 83.96 minutes and IEEE, less than 93 minutes);
- Our JD Power Customer Satisfaction Survey indicated our Electric and Gas Utilities were favorable to our peers in the Midwest;
- Our power generation fleet achieved a forced outage factor of 2.5 percent for coal-fired plants and 1.3 percent for natural gas plants in 2013, compared to an industry average[*] of 7 percent and 5 percent, respectively ([*]NERC GADS 2012 data);
- Our natural gas generation fleet achieved a starting reliability of 99 percent in 2013 while the industry averaged[**] approximately 97 percent ([**]IEEE Data Base 2012);
- Our power generation fleet availability was 97 percent for coal-fired plants, 97 percent for gas-fired plants, 97 percent for diesel-fired plants and 99 percent for wind generation in 2013 while the industry averages^ were 86 percent, 92 percent, 94 percent and 96 percent, respectively (^NERC Data Base, 2012 most recent industry information);
- Our safety record is exemplary with a TCIR rate of 1.7 compared to an industry average of 2.8[*] for TCIR and a DART rate of 0.9 compared to an industry average of 1.4[+] for DART ([+] Most recent industry averages are 2012);
- Our OSHA TCIR rate during construction of our generating facilities is also significantly better than industry average with a TCIR rate of 2 during the construction of the Wygen III coal-fired plant compared to an industry average of 5.1 for coal-fired plants, 1.3 during the construction of the Pueblo Airport Generating Station natural-gas fired plant compared to an industry average of 4.4 for natural-gas fired plants, and 0 during construction of the Busch Ranch wind farm compared to an industry average of 4.4 for wind construction. Our Cheyenne Prairie construction TCIR rate is currently on track to be below industry average;
- Our coal mine completed three years with favorable MSHA safety results compared to other mines located in the Powder River Basin and received an award from the State of Wyoming for three years without a lost time accident.

The electric utility industry is facing requirements to upgrade aging infrastructure, deploy smart grid technology and comply with new state and federal environmental regulations and renewable portfolio standards. Increased energy efficiency, new smart grid technologies and changes in the economy, however, suppress demand in many areas of the United States. These competing considerations will present a challenge to energy companies trying to balance capital spending requirements while obtaining satisfactory rate recovery on this capital spending.

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

In our natural gas and electric utilities, we will continue to work with regulators in our existing service territories to ensure we meet our obligations to serve projected customer demand and to comply with environmental mandates through expansion of infrastructure and construction of new rate-based power generation facilities needed to provide safe, reliable energy. By maintaining our high customer service and reliability standards in a cost-efficient manner, our goal is to secure appropriate rate recovery to provide fair economic returns on our utility investments.

The proliferation of domestic natural gas production from shale plays in recent years provides the domestic market an abundant new supply of natural gas, and has reduced prevailing natural gas prices. This trend is likely to continue.

Therefore, we will continue to prudently grow and develop our existing inventory of crude oil and natural gas reserves, while we strive to maintain strong relationships with mineral owners, landowners and regulatory authorities. We intend to focus our near-term efforts on proving up the substantial Mancos shale gas potential of our San Juan and Piceance Basin properties. Given increased regulatory emphasis on wind and solar power resources, and environmental regulations and legislation that will limit construction of new coal-fired power plants, we believe that natural gas will be the near-term fuel of choice for power generation. Additional gas-fired peaking resources will also be required to provide critical back-up supplies for renewable technologies.

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

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

Key Elements of our Business Strategy

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

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

Rate-base generation assets offer several advantages including:

- Customers - since the generating assets are included in the utility rate base and reviewed and approved by government authorities, customer rates are more stable than if the power was purchased from the open market through wholesale contracts that are renegotiated over time;
- Regulators - regulators participate in a planning process where long-term investments are designed to match long-term energy demand;
- Investors - investors are poised that a long-term, reasonable, stable rate of return may be earned on their investment;
- All - a lower risk profile may improve credit ratings which, in turn, can benefit both consumers and investors by lowering our cost of capital.

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

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

We have and will continue to pursue the purchase of small, private or municipal natural gas distribution systems, which can be easily integrated into our operations. We purchased several small systems in Kansas and Iowa in the past three years, and recently announced the acquisition of another in Wyoming. We have a scalable platform of systems and processes, which simplifies the integration of potential future utility acquisitions. Merger and acquisition activity has continued in the utility industry. We believe that impacts of the recent recession may produce opportunities for healthy utility companies to acquire utility assets and operations of other companies on reasonable terms and conditions. We expect to consider such opportunities if they advance our long-term strategy and maximize shareholder value.

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

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

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

- Colorado legislative mandates apply to our electric utility segment regarding the use of renewable energy. Therefore, we pursue cost-effective initiatives with the regulators that will allow us to meet our renewable energy requirements. Where permitted, we will seek to construct renewable generation resources as rate base assets, which will help mitigate the long-term customer rate impact of adding renewable energy supplies. For example, the Busch Ranch Wind site, a 29 megawatt wind turbine project, was completed in the fourth quarter of 2012, as part of our plan to meet Colorado's Renewable Energy Standard. This site also has significant expansion potential;
- In states such as South Dakota and Wyoming that currently have no legislative mandate on the use of renewable energy, we have proactively integrated cost-effective renewable energy into our generation supply based upon our expectation that there will be mandatory renewable energy standards in the future. For example, under two 20-year PPAs we purchase a total of 60 megawatts of wind energy from wind farms located near Cheyenne, Wyo. for use at Black Hills Power and Cheyenne Light; and
- In all states in which we conduct electric utility operations, we are exploring other potential biomass, solar and wind energy projects, particularly wind generation sites located near our utility service territories.

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

- Through detailed reservoir analysis, apply proven technologies to our existing assets to maximize value;
- Participate in a limited number of selective and meaningful exploration prospects;
- Primarily focus on the Rocky Mountain region, where we can more easily integrate new opportunities with our existing crude oil and natural gas operations as well as our power generation activities. Specifically, we intend to focus our near term efforts on fully developing the substantial shale gas potential of our San Juan and Piceance Basin properties, and participating in select oil exploration prospects with substantial upside opportunities;

- Support the future capital requirements of our drilling program by stabilizing cash flows with a hedging program that mitigates commodity price risk for a portion of our established production for up to three years in the future; and
- Enhance our crude oil and natural gas production activities with the construction or acquisition of mid-stream gathering, compression and treating facilities in a manner that maximizes the economic value of our operations.

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

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

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

Maintain an investment grade credit rating and ready access to debt and equity capital markets. Access to capital has been and will continue to be critical to our success. We have demonstrated our ability to access the debt and equity markets, resulting in sufficient liquidity and solid cash flows. We will require access to the capital markets to fund our planned capital investments or, when possible, to make strategic acquisitions that prudently grow our businesses. Our access to adequate and cost-effective financing depends upon our ability to maintain our investment-grade issuer credit rating.

Moody’s, S&P and Fitch each upgraded our corporate credit rating during 2013, which helped us obtain financing for $525 million in debt at favorable terms.

Prospective Information

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

Utilities Group

Electric Utilities

During 2013, Black Hills Power and Cheyenne Light commenced construction on the new 132 megawatt Cheyenne Prairie generating facility located in Cheyenne, Wyo. and construction is on schedule for commercial operations in the fourth quarter of 2014. Black Hills Power also received approval for increased rates effective June 16, 2013. Preparation continued for the retirement of Ben French, Osage and Neil Simpson I on March 21, 2014, while Colorado Electric retired W.N. Clark and Pueblo Units 5 and 6 on Dec. 31, 2013.

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

- Similar to the construction financing rider approved by the WPSC effective Nov. 1, 2012, for Cheyenne Light and Black Hills Power to earn and collect a rate of return during the construction period on the portion of the financing costs related to serving Wyoming customers, the SDPUC approved a construction financing rider for Black Hills Power's South Dakota customers effective April 1, 2013. On Dec. 2, 2013, Cheyenne Light filed a rate case with the WPSC requesting electric and natural gas revenue increases of $13 million and $1.3 million, respectively, to recover the construction of Cheyenne Prairie and an increase in operating costs. Black Hills Power filed a rate case on Jan. 17, 2014, with the WPSC requesting an electric revenue increase of $2.8 million to recover investment in Cheyenne Prairie, existing infrastructure and increasing operating costs. During the first quarter of 2014, Black Hills Power also intends to file a rate case in South Dakota to recover its investment in Cheyenne Prairie.

- On April 30, 2013, Colorado Electric filed a revised Electric Resource Plan with the CPUC addressing its projected resource requirements through 2019 and seeking to develop and own replacement capacity for the retirement of the coal-fired W.N. Clark power plant to comply with Colorado Clean Air – Clean Jobs Act. On Jan. 6, 2014, the CPUC issued its initial written decision approving a settlement with Colorado Electric on this resource plan, which included the approval to construct a 40 megawatt gas-fired combustion turbine to replace the retirement of the W.N. Clark power plant and to retire the aging natural gas-fired steam turbines, Pueblo Units #5 and #6. A final written order from the CPUC is expected in the first quarter of 2014.

- On Oct. 16, 2013, the CPUC denied Colorado Electric's application for approval of a wind solicitation for the acquisition of up to 30 megawatts of wind energy for its electric system. This solicitation and related requests for proposal were reviewed by an independent evaluator who verified that our Power Generation segment's bid was the lowest cost to customers. The CPUC found that the calculated customer benefits over the 20 year evaluation period were insufficient for all of the bids and stated its preference to consider renewable energy needs in Colorado Electric's Electric Resource Plan hearings held in November 2013. The settlement approved by the CPUC on Jan. 6, 2014, denied any additional wind generation at this time, but indicated that the acquisition of eligible energy resources would be considered in the 2015 to 2017 renewable energy plan to be filed in May 2014.

In October 2013, the City of Rapid City, S.D., experienced the second most severe blizzard in history which left most Black Hills Power customers experiencing power outages. Repairing the substantial and widespread damage far exceeded average annual storm-related costs and in December 2013, Black Hills Power submitted an application to the SDPUC for approval to defer the incremental costs of approximately $2.5 million, including labor, materials and supplies, equipment and outside contractors that were incurred in the efforts to restore power to its customers. In January 2014, approval was received and these costs are included in Regulatory assets until the next rate case filing.

Similar to the Gas Utilities discussed below, Cheyenne Light's gas utility will look for opportunities to purchase local gas distribution systems and infrastructure. In January 2014, Cheyenne Light announced the pending acquisition of assets serving approximately 400 customers.

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Gas Utilities

Weather returned to more normal patterns in the beginning of 2013 but ended colder than normal. Our Gas Utilities continued their focus on investment in our gas distribution network and related technology such as advanced metering infrastructure and mobile data terminals. We continually monitor our investments and costs of operations in all states to determine when additional rate cases or other rate filings will be necessary. As part of our growth strategy, we continue to look for opportunities to purchase municipal and privately-owned gas infrastructure and distribution systems. We acquired five small gas systems during 2013 with a total of approximately 900 customers.

Non-regulated Energy Group

Power Generation

In 2013, Black Hills Wyoming completed the early redemption of high cost project financing along with the settlement of the related interest rate swaps, which will reduce interest expense in future years. Black Hills Wyoming also entered into an agreement to sell its 40 megawatt CTII natural gas-fired generating unit to the City of Gillette for approximately $22 million, upon expiration of the PPA with Cheyenne Light in August 2014. As part of the sale, Black Hills Wyoming will provide services to the City of Gillette through an economy energy PPA. This sale is subject to FERC approval. We plan to continue evaluating opportunities to bid on the construction of generation resources, both new and existing, for our affiliate electric utilities and other regional electric utilities for their energy and capacity needs.

Coal Mining

Production from the Coal Mining segment primarily serves mine-mouth generation plants and select regional customers with long-term fuel needs. Total annual production is estimated to be approximately 4.2 million tons for 2014, which is consistent with 2013. Annual production decreased in 2012 primarily due to the termination of the PacifiCorp Dave Johnston power plant contract which expired at the end of 2011. However, the termination of this contract had a positive impact on earnings since the pricing of this contract did not recover our costs during the latter periods of the agreement. In the second quarter of 2012, the coal mine commenced operations under a revised mine plan. Mining operations moved to an area with lower overburden ratios, which reduced mining costs in 2013.

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

Oil and Gas

During much of 2013, BHEP’s mission was to prove up the value of our existing properties, primarily our Mancos formation shale gas assets in the Piceance and San Juan Basins, while conserving capital and strictly controlling costs. After drilling and completing two exploration wells in the southern Piceance Basin and one exploration well in the San Juan Basin in 2011, the appraisal program was deferred in 2012 due to low natural gas prices. The program continued in 2013 with the drilling of two additional Piceance wells. We will continue our efforts into 2014 to develop attractive oil and gas investment opportunities.

Corporate

Our consolidated interest expense decreased in 2013, primarily due to the repayment of debt in 2012 as well as upgrades to our corporate credit ratings by S&P, Moody's and Fitch. We executed a 10-year $525 million notes offering in November 2013 at an interest rate of 4.25 percent, which we used to repay higher cost debt and settle interest rate swaps. Our interest expense was unfavorably impacted in 2013 by costs related to early retirement of $250 million senior unsecured notes due in 2014, and the settlement of various interest rate swaps. As a result of these financing transactions, we expect our interest expense to decrease further in 2014.

Our new financing allowed for the termination of the de-designated interest rate swaps, which did not qualify for "hedge accounting" treatment provided by accounting standards for derivatives and hedges. With the termination of these swaps, our income statement will no longer reflect the volatility associated with fluctuations in the fair value of these swaps as interest rates change.

Results of Operations

Executive Summary and Overview

	For the Years Ended Dec. 31,				
	2013	Variance	2012	Variance	2011
	(in thousands)				
Revenue					
Utilities	$1,204,997	$123,950	$1,081,047	$(87,868)	$1,168,915
Non-regulated Energy	194,549	(21,690)	216,239	37,867	178,372
Inter-company eliminations	(123,694)	(292)	(123,402)	(48,303)	(75,099)
	$1,275,852	$101,968	$1,173,884	$(98,304)	$1,272,188
Income (loss) from continuing operations					
Electric Utilities	$52,134	$536	$51,598	$3,907	$47,691
Gas Utilities	32,707	4,717	27,990	(6,179)	34,169
Utilities	84,841	5,253	79,588	(2,272)	81,860
Power Generation [(a)]	16,288	(5,040)	21,328	18,317	3,011
Coal Mining	6,327	701	5,626	6,050	(424)
Oil and Gas[(b)]	(4,212)	(1,983)	(2,229)	(508)	(1,721)
Non-regulated Energy	18,403	(6,322)	24,725	23,859	866
Corporate and Eliminations[(c)(d)(e)]	12,602	28,410	(15,808)	26,553	(42,361)
Income from continuing operations	115,846	27,341	88,505	48,140	40,365
Income (loss) from discontinued operations, net of tax[(f)]	(884)	6,093	(6,977)	(16,342)	9,365
Net income (loss)	$114,962	$33,434	$81,528	$31,798	$49,730

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

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

(c) Financial results of Enserco, our Energy Marketing segment, have been reclassified as discontinued operations in accordance with GAAP. When preparing this reclassification, certain indirect corporate costs and inter-segment interest expenses previously charged to our Energy Marketing segment could not be reclassified to discontinued operations of $0.6 million and $2.2 million for 2012 and 2011, respectively, and accordingly have been presented within Corporate. See Note 21 of the Consolidated Financial Statements in this Annual Report on Form 10-K.

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

(e) Includes a $20 million non-cash after-tax mark-to-market gain on certain interest rate swaps in 2013, a $1.2 million non-cash after-tax mark-to-market gain on those same interest rate swaps in 2012 and a $27 million non-cash after-tax mark-to-market loss in 2011 on those same interest rate swaps.

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

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

2013 Compared to 2012

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

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

Business Group highlights for 2013 include:

Utilities Group

Highlights of the Utilities Group include the following:

- On Jan. 17, 2014, Black Hills Power filed a request with the WPSC to increase annual electric revenues by $2.8 million, to recover investments made in electric infrastructure, including Cheyenne Prairie currently under construction. The filing seeks a return on equity of 10.25 percent and a capital structure of approximately 53 percent equity and 47 percent debt.

- On Dec. 2, 2013, Cheyenne Light filed a rate case with the WPSC requesting annual electric and natural gas revenue increases of $12.8 million, and $1.3 million, respectively, to recover investment in Cheyenne Prairie, and existing infrastructure and increasing operating costs. The filing seeks a return on equity of 10.25 percent and a capital structure of 54 percent equity and 46 percent debt.

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

- On Sept. 17, 2013, the SDPUC approved the construction financing rider in lieu of traditional AFUDC with an effective date of April 1, 2013. The rider allows Black Hills Power to earn and collect a rate of return during the construction period on its approximately 40 percent share of the total project cost that relates to South Dakota customers, while also saving customers money over the long-term. Cheyenne Light and Black Hills Power received approval from the WPSC for a similar construction financing rider in November 2012 which allowed Cheyenne Light and Black Hills Power to earn and collect a rate of return during the construction period on approximately a 60 percent share of the project costs related to serving Wyoming customers, while also lowering the overall cost of the project to customers. These riders resulted in an increase to gross margin of $6.9 million in 2013.

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

- During 2013, Cheyenne Light and Black Hills Power commenced construction on Cheyenne Prairie, a facility which will include one simple-cycle, 37 megawatt combustion turbine that will be wholly owned by Cheyenne Light and one combined-cycle, 95 megawatt unit that will be jointly owned by Cheyenne Light and Black Hills Power. Cheyenne Light will own 40 megawatts and Black Hills Power will own 55 megawatts of the combined-cycle unit. Commercial operation is expected in the fourth quarter of 2014. Project costs for plant construction and associated transmission are estimated at $222 million of which approximately $156 million has been spent to date.

- In April 2013, Colorado Electric filed an Energy Resource Plan with the CPUC addressing its projected resource requirements through 2019. The resource plan identified a 40 megawatt, simple-cycle, natural gas-fired turbine as the replacement of W.N. Clark. Additionally, a CPCN was submitted recommending the retirement of Pueblo Unit #5 and #6. On Jan. 6, 2014, the CPUC issued its initial written decision approving the construction of a 40 megawatt gas-fired combustion turbine to replace W.N. Clark and approving the CPCN to the closure of Pueblo Unit #5 and #6. In conjunction with this same energy resource plan, the CPUC denied Colorado Electric’s application for approval to acquire up to 30 megawatts of wind energy.

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

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

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

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

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

Non-regulated Energy Group

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

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

- Black Hills Wyoming entered into an agreement to sell its 40 megawatt CTII natural-gas fired generating unit to the City of Gillette for approximately $22 million and a 20-year economy energy power purchase agreement, subject to closing adjustments. The sale is expected to close in August 2014 upon the expiration of an existing power sale agreement. The sale is subject to FERC approval and certain other requirements included in the contract.

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

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

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

Corporate

Activities at Corporate include the following:

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

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

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

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

Discontinued Operations

On Feb. 29, 2012, we sold the outstanding stock of Enserco, our Energy Marketing segment. The transaction was completed through a stock purchase agreement and certain other ancillary agreements. See Note 21 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for further information on post-closing adjustments.

2012 Compared to 2011

Income from continuing operations was $89 million, or $2.01 per share, in 2012 compared to $40 million, or $1.01 per share, in 2011. The 2012 Income from continuing operations includes a $19 million after-tax gain on sale related to the Williston Basin asset sale, a $17 million non-cash after-tax ceiling test impairment, a $1.0 million non-cash after-tax write-off of deferred financing costs related to our previous Revolving Credit Facility and a $1.2 million non-cash after-tax mark-to-market gain on certain interest rate swaps. The 2011 Income from continuing operations includes a $27 million non-cash after-tax mark-to-market loss on certain interest rate swaps.

Net income was $82 million, or $1.85 per share, in 2012 compared to $50 million, or $1.24 per share, in 2011.

Business Group highlights for 2012 include:

Utilities Group

Highlights of the Utilities Group include the following:

- Our return on investments made in the Utilities Group was positively impacted by new and interim rates and tariffs implemented in three utility jurisdictions during 2012. Consequently, year-to-date revenues were positively impacted for rate increases in 2012 that were not in effect in the prior periods (dollars in millions):

Utility	State	Effective Date	Annual Revenue Increase
Colorado Electric	Colo.	1/2012	$ 28.0
Cheyenne Light	Wyo.	7/2012	4.3
Colorado Gas	Colo.	12/2012	0.2
			$ 32.5

- Colorado Electric's $230 million, 180 megawatt power plant near Pueblo, Colo. began commercial operations and started serving utility customers on Jan. 1, 2012. New rates and cost adjustments were effective Jan. 1, 2012, providing an additional $36 million in gross margins at Colorado Electric for the year ended Dec. 31, 2012.

- On June 18, 2012, the WPSC approved a $2.7 million increase in annual electric revenue and a $1.6 million increase in annual natural gas revenue with a rate of return of 9.6 percent and a capital structure of 54 percent equity and 46 percent debt for Cheyenne Light. New rates were effective July 1, 2012.

- On June 4, 2012, Colorado Gas filed a request with the CPUC for an increase in annual gas revenues to recover capital investments and increased operation and maintenance expenses. The filing was required by the CPUC as part of a 2008 rate case settlement. The CPUC approved a $0.2 million revenue increase with new rates effective Dec. 10, 2012. The settlement includes a return on equity of 9.6 percent and a capital structure of 50 percent equity and 50 percent debt.

- 2012 utility results were unfavorably impacted by warm weather, particularly at the Gas Utilities. Our service territories reported warmer winter weather, as measured by degree days, compared to the 30-year average and the prior year. Heating degree days year-to-date were 13 percent lower than weighted average norms for our Gas Utilities. When compared to colder than normal weather during the same period in 2011, heating degree days were 14 percent lower than the same period in 2011 for our Gas Utilities. For our Electric Utilities, although summer temperatures were above normal, weather-related demand was tempered by lower humidity in 2012 than 2011 in our service territories.

- Cheyenne Light and Black Hills Power received final approvals and permits for Cheyenne Prairie. The WPSC approved the CPCN authorizing the construction, operation and maintenance for the new 132 megawatt natural gas-fired electric generation facility and related gas and electric transmission in Cheyenne, Wyo.

- Cheyenne Light and Black Hills Power received approval from the WPSC to use a construction financing rider for Cheyenne Prairie in lieu of traditional AFUDC. This allows Cheyenne Light and Black Hills Power to earn and collect a rate of return during the construction period on approximately a 60 percent share of the project costs related to serving Wyoming customers, while also lowering the overall cost of the project to customers. This rider was effective Nov. 1, 2012, resulting in an increase to gross margin of $0.2 million in 2012. Black Hills Power filed for a similar construction financing rider in South Dakota. On Jan. 17, 2013, the SDPUC approved a stipulation with interim rates effective April 1, 2013, subject to refund.

- Colorado Electric completed construction of the 29 megawatt Busch Ranch wind project as part of its plan to meet Colorado's Renewable Energy Standard. Colorado Electric's 50 percent share of this project cost approximately $25 million and began serving Colorado Electric customers on Oct. 16, 2012. Colorado Electric entered into a 25-year REPA to purchase the remaining 50 percent wind energy produced by the project. On Jan. 30, 2013, Colorado Electric received approval notification from the United States Treasury for an award letter grant of $8.4 million for our share of the wind project.

- Black Hills Power and Colorado Electric announced plans to suspend plant operations at six older coal-fired and natural gas-fired facilities totaling 152 megawatts primarily due to state and federal environmental regulations and cost to retrofit.

Non-Regulated Energy Group

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

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

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

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

- Construction of gas-fired generation at Black Hills Colorado IPP to serve a 20-year PPA with Colorado Electric was completed and the plant was placed into commercial operations on Jan. 1, 2012. The 200 megawatt project cost approximately $261 million.

Corporate

Activities at Corporate include the following:

- On Feb. 1, 2012, we entered into a new $500 million Revolving Credit Facility expiring Feb. 1, 2017. The facility contains an accordion feature allowing us, with the consent of the administrative agent, to increase the capacity of the facility to $750 million.

- On June 24, 2012, we extended for one year our $150 million term loan at an interest rate of 1.1 percent over LIBOR.

- On Oct. 31, 2012, we redeemed our $225 million senior unsecured, 6.5 percent notes scheduled to mature on May 15, 2013.

- We recognized a non-cash unrealized mark-to-market gain related to certain interest rate swaps of $1.9 million in 2012 compared to a $42 million unrealized mark-to-market loss on these swaps in 2011.

Discontinued Operations

On Feb. 29, 2012, we sold the outstanding stock of Enserco, our Energy Marketing segment. The transaction was completed through a stock purchase agreement and certain other ancillary agreements. Net cash proceeds at the date of sale from the transaction were approximately $165 million, subject to final post-closing adjustments. See Note 21 for further information on post-closing adjustments in our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Operating Results

A discussion of operating results from our business segments follows.

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

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Utilities Group

Non-GAAP Financial Measure

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

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

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

Electric Utilities

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

	2013	Variance	2012	Variance	2011
Revenue - electric	$628,045	$32,503	$595,542	$18,029	$577,513
Revenue - Cheyenne Light gas	37,263	5,839	31,424	(5,394)	36,818
Total revenue	665,308	38,342	626,966	12,635	614,331
Fuel and purchased power - electric	274,963	17,921	257,042	(31,312)	288,354
Purchased gas - Cheyenne Light	19,085	2,653	16,432	(5,566)	21,998
Total fuel and purchased power	294,048	20,574	273,474	(36,878)	310,352
Gross margin - electric	353,082	14,582	338,500	49,341	289,159
Gross margin - Cheyenne Light gas	18,178	3,186	14,992	172	14,820
Total gross margin	371,260	17,768	353,492	49,513	303,979
Operations and maintenance	159,961	13,434	146,527	3,712	142,815
Gain on sale of operating asset	—	—	—	768	(768)
Depreciation and amortization	77,704	2,460	75,244	22,769	52,475
Total operating expenses	237,665	15,894	221,771	27,249	194,522
Operating income	133,595	1,874	131,721	22,264	109,457
Interest expense, net	(56,260)	(5,219)	(51,041)	(12,065)	(38,976)
Other income, net	633	(549)	1,182	701	481

Income tax expense	(25,834)	4,430	(30,264)	(6,993)	(23,271)
Income from continuing operations	$52,134	$536	$51,598	$3,907	$47,691

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	2013	2012	2011
Regulated power plant fleet availability:			
Coal-fired plants [(a)]	96.7%	90.8%	91.3%
Other plants	96.5%	96.9%	96.4%
Total availability	96.6%	93.9%	93.1%

(a) 2012 reflects a planned overhaul at Wygen II. 2011 reflects a major overhaul and an unplanned outage at the Neil Simpson II plant and the PacifiCorp-operated Wyodak plant.

2013 Compared to 2012

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

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

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

Interest expense, net increased primarily due to lower AFUDC.

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

2012 Compared to 2011

Gross margin increased primarily due to a $36 million increase related to rate adjustments that include a return on significant capital investments at Colorado Electric, a $3.5 million increase from the TCA, a $4.4 million increase from wholesale and transmission margins from increased pricing, a $2.1 million construction savings incentive related to the new 180 megawatt generating facility in Pueblo, Colo., a $1.6 million increase from an Environmental Improvement Cost Recovery Adjustment rider at Black Hills Power, partially offset by a decrease of $1.5 million from the expiration of a reserve capacity agreement with PacifiCorp.

Operations and maintenance increased primarily due to the costs associated with operating the new 180 megawatt generating facility in Pueblo, Colo. including increased corporate allocations, partially offset by a $2.1 million reduction of major maintenance accruals related to the power plants announced for retirement and cost reduction initiatives.

Gain on sale of operating assets in 2011 relates to the sale of assets to a related party. The gain was eliminated in the consolidation.

Depreciation and amortization increased primarily due to a higher asset base associated with the new 180 megawatt generating facility in Pueblo, Colo., and the capital lease assets associated with the 200 megawatt generating facility providing capacity and energy from Colorado IPP.

Interest expense, net increased primarily due to debt associated with financing of the new 180 megawatt generating facility for which interest was capitalized during construction in 2011.

Other income (expense), net was comparable to the same period in the prior year.

Income tax benefit (expense): The effective tax rate increased primarily due to an unfavorable true up adjustment in 2012, while the prior year reflected an increased benefit for a repairs deduction taken for tax purposes and the flow-through treatment of such tax benefit.

Gas Utilities

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

	2013	Variance	2012	Variance	2011
Revenue:					
Natural gas - regulated	$510,255	$84,987	$425,268	$(101,704)	$526,972
Other - non-regulated	29,434	621	28,813	1,201	27,612
Total revenue	539,689	85,608	454,081	(100,503)	554,584
Cost of natural gas sold:					
Natural gas - regulated	295,425	64,163	231,262	(85,995)	317,257
Other - non-regulated	15,038	951	14,087	(617)	14,704
Total cost of natural gas sold	310,463	65,114	245,349	(86,612)	331,961
Gross margin:					
Natural gas - regulated	214,830	20,824	194,006	(15,709)	209,715
Other non-regulated	14,396	(330)	14,726	1,818	12,908
Total gross margin	229,226	20,494	208,732	(13,891)	222,623
Operations and maintenance	126,073	8,683	117,390	(4,590)	121,980
Gain on sale of operating assets	—	—	—	—	—
Depreciation and amortization	26,381	1,218	25,163	856	24,307
Total operating expenses	152,454	9,901	142,553	(3,734)	146,287
Operating income	76,772	10,593	66,179	(10,157)	76,336
Interest expense, net	(24,258)	(277)	(23,981)	1,995	(25,976)
Other expense (income), net	(60)	(165)	105	(112)	217
Income tax expense	(19,747)	(5,434)	(14,313)	2,095	(16,408)
Income from continuing operations	$32,707	$4,717	$27,990	$(6,179)	$34,169

2013 Compared to 2012

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

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

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

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

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

2012 Compared to 2011

Gross margin decreased primarily due to an $8.7 million impact from milder weather compared to the same period in the prior year. Heating degree days in 2012 were 14 percent lower than the prior year and 13 percent lower than normal. Also, $6.8 million of costs in 2012 were recorded as a reduction of gross margin, while these costs in 2011 had been recorded in operations and maintenance.

Operations and maintenance decreased primarily due to a reduction in bad debt expense, partially offset by increased compensation and benefits. Also, $6.8 million of costs that in 2011 had been recorded in operations and maintenance were recorded as a reduction of gross margin in 2012.

Depreciation and amortization was comparable to the prior year.

Interest expense, net decreased primarily due to lower interest rates and a decrease in inter-company debt and associated expenses.

Other income (expense), net was comparable to the prior year.

Income tax benefit (expense): The effective tax rate increased as a result of an unfavorable state tax true-up adjustment in 2012. Additionally, the 2011 period was favorably impacted as a result of federal research and development credits and a flow-through tax adjustment at Iowa Gas.

Non-regulated Energy Group

Power Generation

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

	2013	Variance	2012	Variance	2011
Revenue	$83,037	$3,648	$79,389	$47,717	$31,672
Operations and maintenance	30,186	195	29,991	13,453	16,538
Depreciation and amortization	5,091	492	4,599	400	4,199
Total operating expenses	35,277	687	34,590	13,853	20,737
Operating income	47,760	2,961	44,799	33,864	10,935
Interest expense, net	(20,393)	(5,636)	(14,757)	(7,383)	(7,374)
Other income (expense), net	1	(6)	7	(1,087)	1,094
Income tax expense	(11,080)	(2,359)	(8,721)	(7,077)	(1,644)
Income from continuing operations	$16,288	$(5,040)	$21,328	$18,317	$3,011

	2013	2012	2011
Contracted fleet plant availability:			
Gas-fired plants	99.0%	99.4%	98.4%
Coal-fired plants [(a)]	94.5%	99.6%	100.0%
Total	97.9%	99.4%	99.0%

(a) Wygen I experienced a planned outage in 2013.

2013 Compared to 2012

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

Operations and maintenance increased primarily due to two Wygen 1 outages, partially offset by decreased property taxes at Black Hills Colorado IPP.

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

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

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

2012 Compared to 2011

Revenue increased due to the commencement of commercial operation of our new 200 megawatt generating facility in Pueblo, Colo., which began serving customers on Jan. 1, 2012.

Operations and maintenance increased primarily due to the costs to operate our new 200 megawatt generating facility in Pueblo, Colo., which began serving customers on Jan. 1, 2012.

Depreciation and amortization were comparable to the same period in the prior year. The new generating facility's PPA to supply capacity and energy to Colorado Electric is accounted for as a capital lease under GAAP; as such, depreciation expense for the facility is recorded at Colorado Electric for segment reporting purposes.

Interest expense, net increased primarily due to interest expense associated with the financing of the Pueblo generating facility, which was capitalized during construction in 2011, partially offset by lower inter-company debt.

Other income (expense), net included a gain on sale of ownership interest in the partnership that held the Idaho generating facilities in 2011.

Income tax expense: The effective tax rate in 2012 was favorably impacted by a state tax true-up that included certain research and development tax credits.

Coal Mining

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

	2013	Variance	2012	Variance	2011
Revenue	$56,628	$(1,150)	$57,778	$(9,114)	$66,892
Operations and maintenance	39,519	(3,034)	42,553	(14,064)	56,617
Depreciation, depletion and amortization	11,523	(1,537)	13,060	(5,610)	18,670
Total operating expenses	51,042	(4,571)	55,613	(19,674)	75,287
Operating income (loss)	5,586	3,421	2,165	10,560	(8,395)
Interest (expense) income, net	(631)	(1,561)	930	(2,958)	3,888
Other income, net	2,304	(312)	2,616	424	2,192
Income tax benefit (expense)	(932)	(847)	(85)	(1,976)	1,891
Income (loss) from continuing operations	$6,327	$701	$5,626	$6,050	$(424)

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

	2013	2012	2011
Tons of coal sold	4,285	4,246 [a]	5,692
Cubic yards of overburden moved	3,192 [b]	8,329	14,735
Coal reserves at year-end	212,595 [c]	232,265	256,170

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(a) Decrease in tons of coal sold is due to the Dec. 31, 2011 expiration of a coal sales agreement with PacifiCorp's Dave Johnston Plant in Wyoming.

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

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

2013 Compared to 2012

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

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

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

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

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

Revenue decreased primarily due to a 25 percent decrease in tons sold as a result of the expiration of an unprofitable train load-out contract on Dec. 31, 2011, partially offset by increased tons sold to the Wyodak plant that experienced an outage in 2011. Approximately 50 percent of our current coal production is sold under contracts that include price adjustments based on actual mining cost increases.

Operations and maintenance decreased due to reduced overburden moved associated with lower sales volumes related to the expiration of an unprofitable train load-out contract on Dec. 31, 2011. Additionally, a revised mine plan resulted in fuel cost and headcount reductions.

Depreciation, depletion and amortization decreased primarily due to lower equipment usage and lower depreciation of mine reclamation asset retirement costs.

Interest (expense) income, net decreased primarily due to a decrease in inter-company notes receivable upon payment of a dividend to the parent.
Other income, net was comparable to the same period in the prior year.

Income tax benefit (expense): The low effective tax rate in 2012 was primarily due to the impact of percentage depletion and a tax return true-up, while 2011 was impacted by a favorable research and development credit.

Oil and Gas

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

	2013	Variance	2012	Variance	2011
Revenue	$54,884	$(24,188)	$79,072	$(736)	$79,808
Operations and maintenance	40,365	(2,902)	43,267	1,887	41,380
Gain on sale of assets	—	29,129	(29,129)	(29,129)	—
Depreciation, depletion and amortization	21,770	(16,724)	38,494	2,804	35,690
Impairment of long-lived assets	—	(26,868)	26,868	26,868	—
Total operating expenses	62,135	(17,365)	79,500	2,430	77,070
Operating income (loss)	(7,251)	(6,823)	(428)	(3,166)	2,738
Interest expense, net	(614)	3,321	(3,935)	1,959	(5,894)
Other income (expense), net	108	(99)	207	423	(216)
Income tax benefit (expense)	3,545	1,618	1,927	276	1,651
Income (loss) from continuing operations	$(4,212)	$(1,983)	$(2,229)	$(508)	$(1,721)

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

Crude Oil and Natural Gas Production	2013	2012	2011
Bbls of oil sold	336,140	559,971	451,823
Mcf of natural gas sold	6,983,104	8,686,191	8,526,420
Gallons of NGL sold	3,704,639	3,485,514	3,674,814
Mcf equivalent sales	9,529,178	12,543,948	11,762,331

Average Price Received [(a)]	2013	2012	2011
Gas/Mcf	$2.69	$3.33	$4.29
Oil/Bbl	$89.34	$83.27	$79.74
NGL/gallon	$0.79	$0.77	$0.96

(a) Net of hedge settlement gains/losses

	2013	2012	2011
Depletion expense/Mcfe*	$1.83	$2.87	$2.76

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

The following is a summary of certain annual average operating expenses per Mcfe at Dec. 31:

	2013			
	LOE	Gathering Compression and Processing	Production Taxes	Total
San Juan	$1.33	$0.39	$0.45	$2.17
Piceance	0.69	0.56	0.04	1.29
Powder River	1.66	—	1.18	2.84
Williston	1.06	—	1.38	2.44
All other properties	0.86	—	0.18	1.04
Average	$1.22	$0.25	$0.60	$2.07

	2012			
	LOE	Gathering Compression and Processing	Production Taxes	Total
San Juan	$1.22	$0.31	$0.35	$1.88
Piceance	0.30	0.46	0.17	0.93
Powder River	1.57	—	1.18	2.75
Williston	0.35	—	1.35	1.70
All other properties	1.91	—	0.34	2.25
Average	$1.05	$0.19	$0.64	$1.88

	2011			
	LOE	Gathering Compression and Processing	Production Taxes	Total
San Juan	$1.09	$0.35	$0.49	$1.93
Piceance	0.79	0.76	0.11	1.66
Powder River	1.37	—	1.29	2.66
Williston	0.79	—	1.55	2.34
All other properties	1.06	—	0.27	1.33
Average	$1.07	$0.23	$0.70	$2.00

At the East Blanco Field in the San Juan Basin in New Mexico and our Piceance Basin assets in Colorado, we own and operate gas gathering systems, including associated compression and treating facilities.

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

	2013	2012	2011
Bbls of oil (in thousands)	3,921	4,116	6,223
MMcf of natural gas	63,190	55,985	95,904
Total MMcfe	86,713	80,683	133,242

Reserves are based on reports prepared by an independent consulting and engineering firm. The reports were prepared by CG&A. Reserves were determined using SEC-defined product prices. Such reserve estimates are inherently imprecise and may be subject to revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. The current estimate takes into account 2013 production of approximately 9.0 Bcfe, additions from extensions, discoveries and acquisitions (sales) of 12.5 Bcfe and positive revisions to previous estimates of 2.5 Bcfe, primarily due to oil and natural gas pricing.

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

	2013		2012		2011	
	Oil	Gas	Oil	Gas	Oil	Gas
NYMEX prices	$96.94	$3.67	$94.71	$2.76	$96.19	$4.12
Well-head reserve prices	$89.79	$3.45	$85.31	$2.24	$88.49	$3.59

2013 Compared to 2012

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

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

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

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

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

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

Income tax (expense) benefit: Each period presented produced a pre-tax net loss that resulted in an income tax benefit. The effective tax rate in 2013 reflects lower percentage depletion.
2012 Compared to 2011

Revenue was comparable to prior year. Crude oil volumes sold increased 24 percent along with a 4 percent increase in the average price received for crude oil sales, partially offset by a 5 percent decrease in natural gas and NGL volumes sold and a 22 percent decrease in average price received for natural gas. Crude oil production increases reflect volumes from new wells in the Bakken shale formation prior to the sale of a majority of those assets on Sept. 27, 2012.

Operations and maintenance increased primarily due to higher costs from non-operated wells and higher compensation and benefit costs.

Depreciation, depletion and amortization increased primarily due to the year-to-date impact from adjusting our expected 2012 reserves. This was caused by commodity price reserve revisions, as well as higher cost reserves associated with our remaining Bakken activities and a higher depletion rate per Mcfe on higher volumes prior to the sale of most of our Williston Basin assets.

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

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

Interest expense, net decreased primarily due to decreased debt as a result of the sale of the Williston Basin assets along with lower interest rates.

Other income, net was comparable to the prior period.

Income tax (benefit) expense: The effective tax rate for 2011 was positively impacted by a research and development credit and the benefit generated by percentage depletion had a lesser impact on the effective tax rate in 2012.

Corporate

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

2013 Compared to 2012

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

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

2012 Compared to 2011

Corporate results for 2012 included $7.1 million for a make-whole premium related to early retirement of the $225 million senior unsecured notes, and an unrealized, non-cash mark-to-market gain on certain interest rate swaps of approximately $1.9 million compared to an unrealized, non-cash mark-to-market loss of $42 million on these interest rate swaps for the year ended Dec. 31, 2011.

Costs of $0.9 million previously allocated to our Energy Marketing segment were reclassified to the Corporate segment consistent with accounting for discontinued operations for the year ended Dec. 31, 2012 compared to $3.4 million in 2011.

Discontinued Operations

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

The buyer asserted certain purchase price adjustments, some that we accepted, and several that we disputed. The disputed claims were substantially resolved through a binding arbitration decision dated Jan. 17, 2014. We expensed $1.4 million in 2012, related to purchase price adjustments we accepted through a partial settlement agreement with the buyer, and an additional $1.1 million in 2013 related to the claims assigned to arbitration. Loss from discontinued operations was $0.9 million and $7.0 million for the twelve months ended Dec. 31, 2013 and 2012, respectively. Results for 2013 include the resolution of all unresolved purchase price adjustments.

Critical Accounting Estimates

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

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

Goodwill

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

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

We have $353 million in goodwill as of Dec. 31, 2013. The results of our Nov. 30, 2013, annual impairment test indicated that our goodwill was not impaired, since the estimated fair value of all reporting units exceeded their carrying value.

Although an impairment did not exist as of Nov. 30, 2013, we determined that one reporting unit, Colorado Electric with goodwill of $245 million, had an estimated fair value that exceeded its carrying value by only 18 percent, which we do not consider a substantial excess. The result of our valuation analysis estimates Colorado Electric's fair value at $814 million, compared to a carrying value of $690 million as of Nov. 30, 2013. The result of the income approach was sensitive to the 2 percent long-term cash flow growth rate applicable to periods beyond our internal five-year business plan financial forecast and the 5.44 percent weighted-average cost of capital assumptions. As an illustration of this sensitivity, an increase of 0.25 percent in the cost of capital combined with a growth rate reduction of 0.25 percent would result in an estimated fair value in excess of carrying value of $45 million, or 7 percent, as of Nov. 30, 2013.

Full Cost Method of Accounting for Oil and Gas Activities

Accounting for oil and gas activities is subject to special, unique rules. Two generally accepted methods of accounting for oil and gas activities are available - successful efforts and full cost. We account for our oil and gas activities under the full cost method, whereby all productive and nonproductive costs related to acquisition, exploration, development, abandonment and reclamation activities are capitalized. These costs are amortized using a unit-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are generally treated as adjustments to the cost of the properties with no gain or loss recognized. Net capitalized costs are subject to a ceiling test that limits such costs to the aggregate of the present value of future net revenues of proved reserves and the lower of cost or fair value of unproved properties. This method values the reserves based upon SEC-defined prices for oil and gas as of the end of each reporting period adjusted for contracted price changes. The prices, as well as costs and development capital, are assumed to remain constant for the remaining life of the properties. If the net capitalized costs exceed the full-cost ceiling, then a permanent non-cash write-down is required to be charged to earnings in that reporting period. Under these SEC-defined product prices, our net capitalized costs were more than the full cost ceiling at June 30, 2012, which required a write-down of $17 million after-tax. Under the SEC-defined product prices at Dec. 31, 2013, no additional write-down was required. Reserves in 2013 and 2012 were determined consistent with SEC requirements using a 12-month average price calculated using the first-day-of-the-month price for each of the 12 months in the reporting period held constant for the life of the properties. Because of the fluctuations in natural gas and oil prices, we can provide no assurance that future write-downs will not occur.

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

Under the guidance of Rule 4-10, if a gain or loss is recognized on such a sale, total capitalized costs shall be allocated between the reserves sold and the reserves retained on the same basis used to compute amortization, unless there are substantial economic differences between the properties sold and those retained, in which case capitalized costs shall be allocated on the basis of the relative fair value of the properties in the cost center. Because of the substantial differences between the Williston Basin crude oil properties we sold and those properties retained, which were predominantly natural gas, we allocated based on relative fair values.

If a different method of allocating the capitalized costs was chosen, the gain recorded on our transaction could vary substantially. For example, if the allocation was made on the same basis used to compute amortization as noted within Rule 4-10 and we utilized the ratio of proven reserve quantities from the properties sold compared to total proven reserve quantities in our cost center, we would have recorded a gain on sale of approximately $160 million. Because of the value associated with the undeveloped acreage sold, we did not believe this was an appropriate methodology for allocation. If the amount of gain were recorded differently, it would impact the amount of adjustment to our capitalized costs therefore impacting future depletion expense recorded within our consolidated financial statements.
Oil and Natural Gas Reserve Estimates

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

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

Risk Management Activities

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

Derivatives

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

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

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

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

Pension and Other Postretirement Benefits

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

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

The pension benefit cost for 2014 for our non-contributory funded pension plan is expected to be $8.1 million compared to $15 million in 2013. The estimated discount rate used to determine annual benefit cost accruals will be 5.05 percent in 2014; the discount rate used in 2013 was 4.30 percent. In selecting the discount rate, we consider cash flow durations for each plan’s liabilities and returns on high credit quality fixed income yield curves for comparable durations.

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

Change in Assumed Trend Rate	Impact on Dec. 31, 2013 Accumulated Postretirement Benefit Obligation	Impact on 2013 Service and Interest Cost
Increase 1%	$1,914	$136
Decrease 1%	$(1,644)	$(116)

Contingencies

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

Income Taxes

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

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

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. If we determine that we will be unable to realize all or part of our deferred tax assets in the future, an adjustment to the deferred tax asset would be charged to income in the period such determination was made. Although we believe our assumptions, judgments and estimates are reasonable, changes in tax laws or our interpretations of tax laws and the resolution of current and any future tax audits could significantly impact the amounts provided for income taxes in our consolidated financial statements. With respect to changes in tax law, the American Taxpayer Relief Act of 2012, which was enacted Jan. 2, 2013, did not have a material impact on the amounts provided for income taxes including our ability to realize deferred tax assets. As expected, certain provisions of the ATRA involving primarily the extension of 50 percent bonus depreciation resulted in minimal utilization of Federal and state net operating loss carryforwards. In fact, the 50 percent bonus depreciation was a contributing factor to the generation of a net operating loss for Federal and state income tax purposes in 2013.

In addition, on Sept. 13, 2013, the U.S. Treasury issued final regulations addressing the tax consequences associated with amounts paid to acquire, produce, or improve tangible property. The regulations have the effect of a change in law and as a result the impact should be taken into account in the period of adoption. In general, such regulations apply to tax years beginning on or after Jan. 1, 2014, with early adoption permitted. We expect to implement most, if not all, of the provisions of the final regulations in 2014. Procedural guidance is expected from the IRS in early 2014 to facilitate implementation. Analysis performed to date indicates no material impact to our consolidated financial statements. See Note 14 in our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

Liquidity and Capital Resources

OVERVIEW

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

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

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

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

Financial Position Summary	2013	2012
Cash and cash equivalents	$7,841	$15,462
Restricted cash and equivalents	$2	$7,916
Short-term debt, including current maturities of long-term debt	$82,500	$380,973
Long-term debt	$1,396,948	$938,877

Stockholders’ equity	$ 1,307,748	$ 1,232,509
Ratios		
Long-term debt ratio	52 %	43 %
Total debt ratio	53 %	52 %

As described below, during 2013, we issued $800 million in long-term debt and repaid approximately $640 million in short-term and long-term borrowings.

Significant Factors Affecting Liquidity

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

Weather Seasonality, Commodity Pricing and Associated Hedging Strategies

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

Utility Factors

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

Oil and Gas Factors

Our cash flows in our Oil and Gas segment can be subject to fluctuations in commodity prices. Significant changes in crude oil or natural gas commodity prices can have a significant impact on liquidity needs. Since commodity prices are uncontrollable, we have implemented a hedging program to mitigate the effects of significant changes in crude oil and natural gas commodity pricing on existing production. New production is subject to market prices until the production can be quantified and hedged. We use a price-based approach where, based on market pricing, anywhere from 0 percent to 90 percent of our existing natural gas and crude oil production is hedged using options, futures and basis swaps for a maximum term of three years forward. See “Market Risk Disclosures” for hedge details.

Interest Rates

Several of our debt instruments have a variable interest rate component which can change dramatically depending on the economic climate. We deploy hedging strategies that include floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations. At Dec. 31, 2013, 80 percent of our interest rate exposure has been mitigated through either fixed or hedged interest rates.

Until November 2013, we had $250 million notional amount de-designated interest rate swaps. We paid approximately $64 million to settle these swaps in November 2013. For the years ended Dec. 31, 2013, and Dec. 31, 2012, we recorded a $30 million non-cash pre-tax unrealized mark-to-market gain and $1.9 million non-cash pre-tax unrealized mark-to-market gain on these de-designated interest rate swaps, respectively.

We have $75 million notional amount floating-to-fixed interest rate swaps with a maximum remaining term of 3 years. These swaps have been designated as cash flow hedges, and accordingly their mark-to-market adjustments are recorded in accumulated other comprehensive income (loss) on the accompanying Consolidated Balance Sheets. The mark-to-market value of these swaps was a liability of $9.1 million at Dec. 31, 2013.

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

Federal and State Regulations

Federal

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

Income Tax

Acceleration of depreciation for tax purposes including 50 percent bonus depreciation was previously available for certain property placed in service during 2012. The ATRA, enacted into law on Jan. 2, 2013, extended 50 percent bonus depreciation generally to qualifying property placed in service during 2013. These provisions resulted in approximately $273 million of tax benefits for BHC as indicated in the table below:

(in millions)	2013	2012	2011
Tax benefit	$24	$31	$218

In addition, bonus depreciation applies to qualifying property whose construction began before 2014, but will be placed in service on or before Dec. 31, 2014. It is estimated that the tax benefits attributable to such qualifying projects will be approximately $26 million. The additional depreciation deductions will serve to reduce taxable income and contribute to extending the tax loss carryforwards from being fully utilized until 2018 based on current projections.

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

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

CASH GENERATION AND CASH REQUIREMENTS

Cash Generation

Our primary sources of cash are generated from operating activities, our five-year Revolving Credit Facility expiring Feb. 1, 2017, and our ability to access the public and private capital markets through debt and securities offerings when necessary.

Cash Collateral

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

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

Purpose of Cash Collateral	2013	2012
Natural Gas Futures and Basis Swaps Pursuant to Utility Commission Approved Hedging Programs	$10,123	$12,930
Oil and Gas Derivatives	2,501	3,193
Interest Rate Swaps Derivatives Not Designated as Hedges	—	5,960
Total Cash Collateral Positions	$12,624	$22,083

DEBT

Operating Activities

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

Revolving Credit Facility

We have a $500 million revolving corporate credit facility which matures on Feb. 1, 2017, that has an accordion feature which allows us, with the consent of the administrative agent and issuing agents, to increase the capacity of the facility to $750 million. Borrowings are available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings under the agreement are determined based upon our credit ratings. At our current credit rating of BBB equivalent, the margins for base rate borrowings, Eurodollar borrowings and letters of credit are 0.375 percent, 1.375 percent and 1.375 percent, respectively. A commitment fee is charged on the unused amount of the Revolving Credit Facility which is 0.20 percent based on current credit ratings.

Our Revolving Credit Facility at Dec. 31, 2013, had the following borrowings, outstanding letters of credit and available capacity (in millions):

Credit Facility	Expiration	Current Capacity	Borrowings at Dec. 31, 2013	Letters of Credit at Dec. 31, 2013	Available Capacity at Dec. 31, 2013
Revolving Credit Facility	Feb. 1, 2017	$500	$83	$22	$395

The Revolving Credit Facility contains customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions, and maintaining a recourse leverage ratio not to exceed 0.65 to 1.00. Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding. Under the Revolving Credit Facility, our recourse leverage ratio is the ratio of our recourse debt, letters of credit and guarantees issued to our total capital, which is the sum of our recourse debt, letters of credit and guarantees plus our net worth. We were in compliance with these covenants as of Dec. 31, 2013.

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

Capital Resources

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

Recent Financing Transactions

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

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

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

- Settle the $250 million notional de-designated interest rate swaps for approximately $64 million.
- Pay down $55 million of the Revolving Credit Facility.
- Remainder was used for general corporate purposes.

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

On Oct 31, 2012, we redeemed our $225 million senior unsecured 6.50 percent notes, which were originally scheduled to mature on May 15, 2013. The total payment was $239 million, including accrued interest and a make-whole provision of $7.1 million pre-tax.

In May 2012, Black Hills Power's 4.8 percent Pollution Control Revenue Bonds were paid in full for $6.5 million principal and interest.

Future Financing Plans

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

- Review long-term debt financing options, including the potential issuance of utility first mortgage bonds, for a portion of the estimated $222 million Cheyenne Prairie capital project.
- Extension of our Revolving Credit Facility which expires in 2017.

Cross-Default Provisions

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

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

Equity

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

Shelf Registration

We have an effective automatic shelf registration statement on file with the SEC under which we may issue, from time to time, senior debt securities, subordinated debt securities, common stock, preferred stock, warrants and other securities. Although the shelf registration statement does not limit our issuance capacity, our ability to issue securities is limited to the authority granted by our Board of Directors, certain covenants in our financing arrangements and restrictions imposed by federal and state regulatory authorities. This shelf registration statement expires in June 2014, and we plan to file a new shelf registration statement with the SEC before it expires. Our articles of incorporation authorize the issuance of 100 million shares of common stock and 25 million shares of preferred stock. As of Dec. 31, 2013, we had approximately 44 million shares of common stock outstanding and no shares of preferred stock outstanding.

Common Stock Dividends

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

In January 2014, our Board of Directors declared a quarterly dividend of $0.39 per share or an annualized equivalent dividend rate of $1.56 per share. The table below provides our historical three-year dividend payout ratio and dividends paid per share.

	2013	2012	2011
Dividend Payout Ratio	59%	80%	118%
Dividends Per Share	$1.52	$1.48	$1.46

Our three-year compound annualized dividend growth rate was 1.8 percent, and all dividends were paid out of available operating cash flows.

Dividend Restrictions

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

Our credit facilities and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be deemed to have occurred if we did not meet certain financial covenants. The most restrictive financial covenants of our Revolving Credit Facility include the following: a recourse leverage ratio not to exceed .65 to 1.00 and a minimum consolidated net worth of $625 million plus 50 percent of aggregate consolidated net income since Jan. 1, 2005. As of Dec. 31, 2013, we were in compliance with these covenants.

Covenants within Cheyenne Light's financing agreements require Cheyenne Light to maintain a debt to capitalization ratio of no more than .60 to 1.00. Our utilities in Colorado, Iowa, Kansas and Nebraska have regulatory agreements in which they cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40 percent of their total capitalization; and neither Black Hills Utility Holdings nor its utility subsidiaries can extend credit to the Company except in the ordinary course of business and upon reasonable terms consistent with market terms. Additionally, our utility subsidiaries may generally be limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As of Dec. 31, 2013, the restricted net assets at our Electric and Gas Utilities were approximately $88 million.

Utility Money Pool

As a utility holding company, we are required to establish a cash management program to address lending and borrowing activities between our utility subsidiaries and the Company. We have established utility money pool agreements which address these requirements. These agreements are on file with the FERC and appropriate state regulators. Under the utility money pool agreements, our utilities may at their option, borrow and extend short-term loans to our other utilities via a utility money pool at market-based rates (1.6 percent at Dec. 31, 2013). While the utility money pool may borrow funds from the Company (as ultimate parent company), the money pool arrangement does not allow loans from our utility subsidiaries to the Company (as ultimate parent company) or to non-regulated affiliates.

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

	Borrowings From (Loans To) Money Pool Outstanding	
Subsidiary	2013	2012
Black Hills Utility Holdings	$128,587	$27,852
Black Hills Power	(17,293)	(31,645)
Cheyenne Light	65,772	5,277
Total Money Pool borrowings from Parent	$177,066	$1,484

CASH FLOW ACTIVITIES

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

	2013	2012	2011
Cash provided by (used in)			
Operating activities	$324,629	$316,971	$223,704
Investing activities	$(349,278)	$11,169	$(447,007)
Financing activities	$17,028	$(371,446)	$249,633

2013 Compared to 2012

Operating Activities:

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

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

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

- A $13 million contribution in 2013 to our defined benefit plans compared to $25 million in 2012; and

- 2013 included cash outflows from operating activities of $0.9 million for post-closing adjustments resulting from the sale of our Energy Marketing segment in 2012 compared to 2012 which included a $21 million cash inflow from operating activities in our Energy Marketing segment.

Investing Activities:

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

- In 2012, proceeds from sale of assets was $254 million which included $228 million from the sale of a majority of our Williston Basin assets by our Oil and Gas segment, and $25 million from the partial sale of the Busch Ranch Wind project;
- In 2012, we received proceeds of $108 million from the sale of Enserco; and
- In 2013, we had comparable capital expenditures to 2012, with an increase of $5.6 million primarily due to the construction of Cheyenne Prairie.

Financing Activities:

Net cash provided by financing activities was $17 million in 2013, which was an increase in inflow of $388 million from 2012 primarily attributable to:

- In 2013, we re-paid $250 million senior unsecured notes plus a make-whole premium of approximately $8.5 million, paid off the Black Hills Wyoming project debt for approximately $96 million and settled associated interest rate swaps for approximately $8.5 million, repaid $55 million on Revolving Credit Facility, and settled the de-designated interest rate swaps for approximately $64 million with proceeds from issuance of a senior unsecured notes for $525 million;
- In 2013, we entered into a long-term Corporate term loan for $275 million which was primarily used to repay the $100 million long-term term loan, the $150 million short-term term loan and a portion of the Revolving Credit Facility;
- In 2012, we repaid our $225 million senior unsecured 6.5 percent notes with proceeds from the sale of Williston Basin assets and Black Hills Power repaid its $6.5 million Pollution Control Revenue Bonds. The redemption of the notes required a make-whole provision payment of $7.1 million;
- In 2012, we repaid short-term borrowings from proceeds from the sale of Enserco partially offset by the use of short-term borrowings to fund the construction of Cheyenne Prairie; and
- Cash dividends on common stock of $68 million were paid in 2013 compared to $65 million paid in 2012.

2012 Compared to 2011

Operating Activities:

Net cash provided by operating activities was $93 million higher than in 2011 primarily attributable to:

- Cash earnings (income from continuing operations plus non-cash adjustments) were $47 million higher than prior year;
- Net inflows from operating assets and liabilities of continuing operations of $40 million higher than prior year. The increase primarily related to decreased gas volumes in inventory, the decrease in accounts payable of approximately

$9.0 million due to the expiration of Colorado Electric’s contract with PSCo at Dec. 31, 2011, and other normal working capital changes;

- A $25 million contribution in 2012 to our defined benefit plans compared to $11 million in 2011; and

- A $14 million increase in net cash inflows from discontinued operations in 2012 compared to 2011.

Investing Activities:

Net cash provided by investing activities was $11 million in 2012 compared to net cash used in investing activities of $447 million in 2011 for a net inflow of $458 million. The change was driven by:

- Cash proceeds from assets sold during 2012, including $228 million from the sale of approximately 85 percent of our Williston Basin assets by our Oil and Gas segment, $25 million from the sale of a 50 percent ownership interest in the Busch Ranch Wind project, and $108 million from the sale of Enserco; and

- In 2012, we had lower capital expenditures of $92 million primarily due to the completion of construction of our Pueblo generation facility.

Financing Activities:

Cash used in financing activities was $371 million in 2012, which was an increase in outflow of $621 million from 2011 primarily attributable to:

- During 2012, approximately $110 million of the proceeds from the sale of Enserco were used to pay down short-term borrowings on the Revolving Credit Facility. Additional borrowings on the Revolving Credit Facility were primarily used for our working capital needs, while in 2011 we increased short-term borrowings by approximately $196 million primarily due to our continued construction in Colorado;

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

- Cash dividends on common stock of $65 million were paid in 2012 compared to $59 million paid in 2011; and

- In 2011, we issued common stock for proceeds of $123 million primarily from an equity forward transaction.

CAPITAL EXPENDITURES

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

Historically, a significant portion of our capital expenditures relate primarily to assets that may be included in utility rate base, and if considered prudent by regulators, can be recovered from our utility customers. Those capital expenditures also earn a rate of return authorized by the commissions in the jurisdictions in which we operate and are subject to rate agreements. During 2013, our Electric Utilities' capital expenditures included the continued construction of Cheyenne Prairie, and improvements to generating stations, transmission and distribution lines. Capital expenditures associated with our Gas Utilities are primarily to improve or expand the existing gas distribution network. In addition to our utility capital expenditures, we allocate a portion of our capital budget to Non-regulated operations with specific focus on our oil and gas drilling program. We believe that cash generated from operations and borrowing on our existing Revolving Credit Facility will be adequate to fund ongoing capital expenditures, including construction of Cheyenne Prairie. We would ultimately expect to finance this new generation with long-term debt.

Historical Capital Requirements

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

	2013	2012	2011
Property additions [(a)]:			
Utilities -			
Electric Utilities [(b)]	$222,262	$167,263	$173,078
Gas Utilities	63,205	45,711	43,954
Non-regulated Energy -			
Power Generation [(c)]	13,533	5,547	98,927
Coal Mining	5,528	13,420	10,438
Oil and Gas [(d)]	64,687	107,839	89,672
Corporate	10,319	7,376	13,279
Capital expenditures for continuing operations	379,534	347,156	429,348
Discontinued operations investing activities	—	824	2,359
Total expenditures for property, plant and equipment	379,534	347,980	431,707
Common stock dividends	67,587	65,262	59,202
Maturities/redemptions of long-term debt	445,906	240,077	8,382
Discontinued operations financing activities	—	—	158
	$893,027	$653,319	$499,449

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

(b) 2013 includes costs relating to Cheyenne Prairie which began construction in the spring of 2013; 2012 included construction of our 50 percent ownership in the Busch Ranch Wind Project; and 2011 included costs relating to construction of the 180 megawatt natural gas-fired generation facility at Colorado Electric.

(c) 2011 includes costs relating to the construction of the 200 megawatt natural gas-fired power generation facility at Black Hills Colorado IPP.

(d) Decrease in expenditures due to drilling and completion delays.

Forecasted Capital Requirements

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

	2014	2015	2016
Utilities:			
Electric Utilities[(1)]	$250,700	$189,300	$160,500
Gas Utilities	63,000	62,000	47,600
Non-regulated Energy:			
Power Generation	2,500	5,200	3,200
Coal Mining	6,600	6,200	7,300
Oil and Gas	117,800	122,700	122,200
Corporate	8,700	5,900	6,100
	$449,300	$391,300	$346,900

(1) Capital expenditures for our Electric Utilities are forecasted to include approximately $68 million associated with the construction of Cheyenne Prairie during 2014.

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

CREDIT RATINGS AND COUNTERPARTIES

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

The following table represents the credit ratings, outlook and risk profile of BHC at Dec. 31, 2013:

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

(a) On July 24, 2013, S&P upgraded our credit rating to BBB with a Stable outlook.
(b) On Sept. 25, 2013, Moody’s upgraded the BHC credit rating to Baa2 with a Positive outlook.
Subsequently, on Jan. 30, 2014, Moody’s upgraded the BHC credit rating to Baa1with a Stable outlook.
(c) On May 10, 2013, Fitch upgraded our credit rating to BBB with a Positive outlook.

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

The following table represents the credit ratings of Black Hills Power at Dec. 31, 2013:

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

* On July 24, 2013, S&P upgraded the BHP credit rating to A- with a Stable outlook.
** On Sept. 25, 2013, Moody’s upgraded the BHP credit rating to A2. Subsequently, on Jan. 30, 2014, Moody’s upgraded the BHP credit rating to A1.

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

CONTRACTUAL OBLIGATIONS AND OTHER COMMITMENTS

Contractual Obligations

In addition to our capital expenditure programs, we have contractual obligations and other commitments that will need to be funded in the future. The following information summarizes our cash obligations and commercial commitments at Dec. 31, 2013. Actual future costs of obligations may differ materially from these estimated amounts (in thousands):

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Long-term debt[(a)(b)]	$1,397,055	$—	$275,000	$—	$1,122,055
Unconditional purchase obligations[(c)]	873,292	203,131	410,869	236,661	22,631
Operating lease obligations[(d)]	16,199	2,782	6,268	2,774	4,375
Other long-term obligations[(e)]	51,851	—	—	—	51,851
Employee benefit plans[(f)]	134,758	5,315	50,655	39,521	39,267
Liability for unrecognized tax benefits in accordance with accounting guidance for uncertain tax positions[(g)]	37,630	—	10,127	4,080	23,423
Notes payable	82,500	82,500	—	—	—
Total contractual cash obligations[(h)]	$2,593,285	$293,728	$752,919	$283,036	$1,263,602

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

(b) The following amounts are estimated for interest payments over the next five years based on a mid-year retirement date for long-term debt expiring during the identified period: $62 million in 2014, $60 million in 2015, $59 million in 2016, $59 million in 2017, and $59 million in 2018. Estimated interest payments on variable rate debt are calculated by utilizing the applicable rates as of Dec. 31, 2013.

(c) Unconditional purchase obligations include the energy and capacity costs associated with our PPAs, capacity and certain transmission, gas purchases, gas transportation and storage agreements, and gathering commitments for our Oil and Gas segment. The energy charge under the PPAs and the commodity price under the gas purchase contracts are variable costs, which for purposes of estimating our future obligations, were based on costs incurred during 2013 and price assumptions using existing prices at Dec. 31, 2013. Our transmission obligations are based on filed tariffs as of Dec. 31, 2013. A portion of our gas purchases are purchased under evergreen contracts and therefore, for purposes of this disclosure, are carried out for 60 days. The gathering commitments for our Oil and Gas segment are described in Part I, Delivery Commitments, of this Annual Report filed on Form 10-K.

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

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

(f) Represents both estimated employer contributions to Defined Benefit Pension Plans and payments to employees for the Non-Pension Defined Benefit Postretirement Healthcare Plans and the Supplemental Non-Qualified Defined Benefit Plans through the year 2023.

(g) Years 1-3 include an estimated reversal of approximately $6.3 million associated with the gain deferred from the tax treatment related to the IPP Transaction and the Aquila Transaction.

(h) Amounts in the table exclude: (1) any obligation that may arise from our derivatives, including interest rate swaps and commodity related contracts that have a negative fair value at Dec. 31, 2013. These amounts have been excluded as it is impractical to reasonably estimate the final amount and/or timing of any associated payments. (2) A portion of our gas purchases are hedged. These hedges are in place to reduce our customers' underlying exposure to commodity price fluctuations. The impact of these hedges is not included in the above table. (3) The obligations presented above do not include inter-company transactions and obligations negotiated for the construction of Cheyenne Prairie. This 132 megawatt generating facilities is expected to cost $222 million for which we have secured 100 percent of the procurement contracts as of Dec. 31, 2013.

Off-Balance Sheet Commitments

Guarantees

We have entered into various off-balance sheet commitments in the form of guarantees and letters of credit. We provide various guarantees supporting certain of our subsidiaries under specified agreements or transactions. At Dec. 31, 2013, we had outstanding guarantees as indicated in the table below. Of the $134 million, $70 million was related to performance obligations under subsidiary contracts and $64 million was related to indemnification for reclamation and surety bonds of subsidiaries. For more information on these guarantees, see Note 19 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

We had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at Dec. 31, 2013	Year Expiring
Guarantees for payment of obligations arising from commodity-related physical and financial transactions by Black Hills Utility Holdings	$70,000	Ongoing
Indemnification for subsidiary reclamation/surety bonds	64,449	Ongoing
	$134,449	

Letters of Credit

Letters of credit reduce the borrowing capacity available on our corporate Revolving Credit Facility. We had $22 million in letters of credit issued under our Revolving Credit Facility at Dec. 31, 2013.

Market Risk Disclosures

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operations of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures.

Market risk is the potential loss that may occur as a result of an adverse change in market price or rate. We are exposed to the following market risks, including, but not limited to:

- Commodity price risk associated with our natural long position with crude oil and natural gas reserves and production and fuel procurement for certain of our gas-fired generation assets; and

- Interest rate risk associated with our variable rate debt and our other short-term and long-term debt instruments as described in Notes 5 and 6 of our Notes to Consolidated Financial Statements.

Our exposure to these market risks is affected by a number of factors including the size, duration, and composition of our energy portfolio, the absolute and relative levels of interest rates and commodity prices, the volatility of these prices and rates, and the liquidity of the related interest rate and commodity markets.

The Black Hills Corporation Risk Policies and Procedures have been approved by our Executive Risk Committee and reviewed by the Audit Committee of our Board of Directors. These policies relate to numerous matters including governance, control infrastructure, authorized commodities and trading instruments, prohibited activities, and employee conduct. The Executive Risk Committee, which includes senior level executives, meets on a regular basis to review our business and credit activities and to ensure that these activities are conducted within the authorized policies.

Utilities Group

We produce, purchase and distribute power in four states, and purchase and distribute natural gas in five states. All of our utilities have GCA provisions that allow them to pass the prudently-incurred cost of gas through to the customer. To the extent that gas prices are higher or lower than amounts in our current billing rates, adjustments are made on a periodic basis to “true-up” billed amounts to match the actual natural gas cost we incurred. In South Dakota, Colorado, Wyoming and Montana, we have a mechanism for our regulated electric utilities that serves a purpose similar to the GCAs for our regulated gas utilities. To the extent that our fuel and purchased power costs are higher or lower than the energy cost built into our tariffs, the difference (or a portion thereof) is passed through to the customer. These adjustments are subject to periodic prudence reviews by the state utility commissions.

The operations of our utilities, including power purchase arrangements where our utilities must provide the generation fuel (tolling agreements), expose our utility customers to volatility in natural gas prices; therefore, as allowed or required, by state utility commissions, we have entered into commission-approved hedging programs utilizing natural gas futures, options and basis swaps to reduce our customers’ underlying exposure to these fluctuations. These transactions are considered derivatives, and in accordance with accounting standards for derivatives and hedging, mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets, net of balance sheet offsetting as permitted by GAAP. Unrealized and realized gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in the accompanying Consolidated Balance Sheets in accordance with the state utility commission guidelines. Accordingly, the hedging activity is recognized in the Consolidated Statements of Income (Loss) or the Consolidated Statements of Comprehensive Income (Loss) when the related costs are recovered through our rates.

The fair value of our Utilities Group derivative contracts at Dec. 31 is summarized below (in thousands):

	2013		2012	
Net derivative liabilities	$(6,071	)	$(8,533	)
Cash collateral	10,123		12,930	
	$4,052		$4,397	

Oil and Gas

Oil and Gas Exploration and Production

We produce natural gas and crude oil through our exploration and production activities. Our natural long positions, or unhedged open positions, result in commodity price risk and variability to our cash flows.

To mitigate commodity price risk and preserve cash flows, we primarily use over-the-counter swaps, exchange traded futures and related options to hedge portions of our crude oil and natural gas production. We elect hedge accounting on these instruments. Our hedging policy allows up to 90 percent of our natural gas and crude oil production from proven producing reserves to be hedged for a period up to three years in the future. Some of our commodity contracts are subject to master netting agreements, where our asset and liability positions include cash collateral that allow us to settle positive and negative positions.

We have entered into agreements to hedge a portion of our estimated 2014 and 2015 natural gas and crude oil production from the Oil and Gas segment. The hedge agreements in place as of Dec. 31, 2013, are as follows:

Natural Gas

	For the Three Months Ended				
	March 31,	June 30,	Sept. 30,	Dec. 31,	Total Year
2014					
Swaps - MMBtu	1,132,500	1,132,500	1,050,000	1,050,000	4,365,000
Weighted Average Price per MMBtu	$3.80	$3.82	$3.99	$3.99	$3.90
2015					
Swaps - MMBtu	900,000	862,500	500,000	455,000	2,717,500
Weighted Average Price per MMBtu	$4.24	$3.99	$4.08	$4.16	$4.12

Crude Oil

	For the Three Months Ended				
	March 31,	June 30,	Sept. 30,	Dec. 31,	Total Year
2014					
Swaps - Bbls	60,000	60,000	57,000	57,000	234,000
Weighted Average Price per Bbl	$95.48	$90.65	$90.55	$90.66	$91.86
2015					
Swaps - Bbls	55,500	51,000	39,000	33,000	178,500
Weighted Average Price per Bbl	$89.98	$87.84	$87.73	$87.36	$88.39

Our hedge agreements had a fair value, net of cash collateral, of approximately $0.1 million as of Dec. 31, 2013.

Wholesale Power

A potential risk related to power sales is the price risk arising from the sale of wholesale power that exceeds our generating capacity. These potential short positions can arise from unplanned plant outages or from unanticipated load demands. To control such risk, we restrict wholesale off-system sales to amounts by which our anticipated generating capabilities and purchased power resources exceed our anticipated load requirements plus a required reserve margin.

Financing Activities

We engage in activities to manage risks associated with changes in interest rates. We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations. At Dec. 31, 2013, we had $75 million of notional amount floating-to-fixed interest rate swaps, with a maximum term of 3 years. These swaps have been designated as cash flow hedges in accordance with accounting standards for derivatives and hedges and accordingly their mark-to-market adjustments are recorded in Accumulated other comprehensive loss on the accompanying Consolidated Balance Sheets.

Further details of the swap agreements are set forth in Note 8 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

On Dec. 31, 2013, and Dec. 31, 2012, our interest rate swaps and related balances were as follows (dollars in thousands):

	Notional	Weighted Average Fixed Interest Rate	Maximum Terms in Years	Current Liabilities, net of Cash Collateral	Non-current Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)	Pre-tax Unrealized Gain (Loss)
Dec. 31, 2013							
Interest rate swaps	$75,000	4.97 %	3	$3,474	$5,614	$ (9,088)	$ —
Dec. 31, 2012							
Interest rate swaps [(a)]	$150,000	5.04 %	4	$7,039	$16,941	$ (23,980)	$ —
Interest rate swaps - De-designated [(b)]	250,000	5.67 %	1	88,148	—	—	1,882
	$400,000			$95,187	$16,941	$ (23,980)	$ 1,882

(a) Certain interest rate swaps designated as cash flow hedges were settled during 2013. See Note 8 of the Notes to the Consolidated Financial Statements in this Annual Report on Form10-K.

(b) These de-designated swaps were settled in November 2013 for approximately $64 million. Pre-tax non-cash unrealized gain recognized on these swaps prior to settlement was $30 million.

Based on Dec. 31, 2013, market interest rates and balances, a loss of approximately $3.5 million would be realized and reported in pre-tax earnings during the next 12 months. Estimated and realized losses will likely change during the next twelve months as market interest rates change.

The table below presents principal amounts and related weighted average interest rates by year of maturity for our long-term debt obligations, including current maturities (dollars in thousands):

	2014	2015	2016	2017	2018	Thereafter	Total
Long-term debt							
Fixed rate[(a)]	$—	$—	$—	$—	$—	$1,102,200	$1,102,200
Average interest rate [(b)]	— %	— %	— %	— %	— %	5.31 %	5.31 %
Variable rate	$—	$275,000	$—	$—	$—	$19,855	$294,855
Average interest rate [(b)]	— %	1.31 %	— %	— %	— %	0.20 %	1.24 %
Total long-term debt	$—	$275,000	$—	$—	$—	$1,122,055	$1,397,055
Average interest rate [(b)]	— %	1.31 %	— %	— %	— %	5.22 %	4.45 %

(a) Excludes unamortized premium or discount.
(b) The average interest rates do not include the effect of interest rate swaps.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty. We have adopted the Black Hills Corporation Credit Policy that establishes guidelines, controls, and limits to manage and mitigate credit risk within risk tolerances established by the Board of Directors. In addition, our Executive Risk Committee, which includes senior executives, meets on a regular basis to review our credit activities and to monitor compliance with the adopted policies.

We seek to mitigate our credit risk by conducting a majority of our business with investment grade companies, setting tenor and credit limits commensurate with counterparty financial strength, obtaining netting agreements, and securing our credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit, and other security agreements.

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer's current creditworthiness, as determined by our review of their current credit information. We maintain a provision for estimated credit losses based upon our historical experience and any specific customer collection issue that we have identified. While most credit losses have historically been within our expectations and provisions established, we cannot provide assurance that we will continue to experience the same credit loss rates that we have in the past, or that an investment grade counterparty will not default sometime in the future.

At Dec. 31, 2013, our credit exposure included a $0.5 million exposure to a non-investment grade energy marketing company. The remainder of our credit exposure was concentrated primarily among investment grade companies, municipal cooperatives and federal agencies.

New Accounting Pronouncements

See Note 1 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for information on new accounting standards adopted in 2013 or pending adoption.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Management's Report on Internal Control over Financial Reporting

We are responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.
Under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of Dec. 31, 2013, based on the criteria set forth in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on our evaluation, we have concluded that our internal control over financial reporting was effective as of Dec. 31, 2013.

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of Black Hills Corporation's financial statements, has issued an attestation report on the effectiveness of Black Hills Corporation's internal control over financial reporting as of Dec. 31, 2013. Deloitte & Touche LLP's report on Black Hills Corporation's internal control over financial reporting is included herein.

Black Hills Corporation

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Black Hills Corporation
Rapid City, South Dakota

We have audited the accompanying consolidated balance sheets of Black Hills Corporation and subsidiaries (the “Company”) as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income (loss), common stockholders’ equity and cash flows for each of the three years in the period ended December 31, 2013. Our audits also included the financial statement schedules listed in the Index at Item 15. These consolidated financial statements and financial statement schedules are the responsibility of the Company’s management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Black Hills Corporation and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company’s internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2014 expressed an unqualified opinion on the Company’s internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 25, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Black Hills Corporation
Rapid City, South Dakota

We have audited the internal control over financial reporting of Black Hills Corporation and subsidiaries (the "Company") as of December 31, 2013, based on criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2013 of the Company and our report dated February 25, 2014 expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 25, 2014

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

Year ended	Dec. 31, 2013	Dec. 31, 2012	Dec. 31, 2011
	(in thousands, except per share amounts)		
Revenue:			
Utilities	$1,191,133	$1,064,813	$1,155,519
Non-regulated energy	84,719	109,071	116,669
Total revenue	1,275,852	1,173,884	1,272,188
Operating expenses:			
Utilities -			
Fuel, purchased power and cost of natural gas sold	492,147	407,066	574,989
Operations and maintenance	261,919	242,367	247,496
Non-regulated energy operations and maintenance	83,762	85,830	93,453
Gain on sale of operating assets	—	(29,129)	—
Depreciation, depletion and amortization	141,217	154,632	135,591
Impairment of long-lived assets	—	26,868	—
Taxes - property, production and severance	40,012	40,487	33,710
Other operating expenses	1,243	2,052	710
Total operating expenses	1,020,300	930,173	1,085,949
Operating income	255,552	243,711	186,239
Other income (expense):			
Interest charges -			
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts and realized settlements on interest rate swaps)	(113,979)	(117,754)	(116,684)
Allowance for funds used during construction - borrowed	1,130	3,462	14,041
Capitalized interest	1,061	682	11,260
Unrealized gain (loss) on interest rate swaps, net	30,169	1,882	(42,010)
Interest income	1,723	1,957	2,017
Allowance for funds used during construction - equity	607	540	932
Other expense	(694)	(71)	(817)
Other income	1,971	2,486	2,490
Total other income (expense)	(78,012)	(106,816)	(128,771)
Income (loss) from continuing operations before earnings (loss) of unconsolidated subsidiaries and income taxes	177,540	136,895	57,468
Equity in earnings (loss) of unconsolidated subsidiaries	(86)	10	1,121
Income tax benefit (expense)	(61,608)	(48,400)	(18,224)
Income (loss) from continuing operations	115,846	88,505	40,365
Income (loss) from discontinued operations, net of tax	(884)	(6,977)	9,365
Net income (loss) available for common stock	$114,962	$81,528	$49,730
Earnings (loss) per share of common stock:			
Earnings (loss) per share, Basic -			
Income (loss) from continuing operations, per share	$2.62	$2.02	$1.01
Income (loss) from discontinued operations, per share	(0.02)	(0.16)	0.24
Total income (loss) per share, Basic	$2.60	$1.86	$1.25

Earnings (loss) per share, Diluted -			
Income (loss) from continuing operations, per share	$2.61	$2.01	$1.01
Income (loss) from discontinued operations, per share	(0.02)	(0.16)	0.23
Total income (loss) per share, Diluted	$2.59	$1.85	$1.24
Weighted average common shares outstanding:			
Basic	44,163	43,820	39,864
Diluted	44,419	44,073	40,081

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

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

Years ended (in thousands)	Dec. 31, 2013	Dec. 31, 2012	Dec. 31, 2011
Net income (loss) available for common stock	$114,962	$81,528	$49,730
Other comprehensive income (loss), net of tax:			
Benefit plan liability adjustments - net gain (loss) (net of tax of $(3,813), $296 and $4,135, respectively)	8,237	(542)	(7,609)
Benefit plan liability adjustments - prior service (costs) (net of tax of $185, $86 and $176, respectively)	(406)	(157)	(325)
Reclassification adjustment of benefit plan liability - net gain (loss) (net of tax of $(971), $0 and $0)	1,820	—	—
Reclassification adjustment of benefit plan liability - prior service cost (net of tax of $88, $0 and $0)	(165)	—	—
Fair value adjustment on derivatives designated as cash flow hedges (net of tax of $(2,445), $887 and $1,708, respectively)	4,534	(1,268)	(2,831)
Reclassification adjustment of cash flow hedges settled and included in net income (loss) (net of tax of $(2,016), $534 and $(709), respectively)	4,046	(643)	1,468
Other comprehensive income (loss), net of tax	18,066	(2,610)	(9,297)
Comprehensive income (loss)	$133,028	$78,918	$40,433

See Note 15 for additional disclosures related to Comprehensive Income.

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

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BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS

	As of Dec. 31, 2013 (in thousands)	Dec. 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$7,841	$15,462
Restricted cash and equivalents	2	7,916
Accounts receivable, net	177,573	163,698
Materials, supplies and fuel	88,478	77,643
Derivative assets, current	717	3,236
Income tax receivable, net	1,460	—
Deferred income tax assets, net, current	18,889	77,231
Regulatory assets, current	24,451	31,125
Other current assets	25,877	28,795
Total current assets	345,288	405,106
Investments	16,697	16,402
Property, plant and equipment	4,259,445	3,930,772
Less accumulated depreciation and depletion	(1,269,148)	(1,188,023)
Total property, plant and equipment, net	2,990,297	2,742,749
Other assets:		
Goodwill	353,396	353,396
Intangible assets, net	3,397	3,620
Derivative assets, non-current	—	510
Regulatory assets, non-current	138,197	188,268
Other assets, non-current	27,906	19,420
Total other assets, non-current	522,896	565,214
TOTAL ASSETS	$3,875,178	$3,729,471

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

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS
(Continued)

	As of	
	Dec. 31, 2013	Dec. 31, 2012
	(in thousands, except share amounts)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$130,416	$84,422
Accrued liabilities	151,277	154,389
Derivative liabilities, current	3,474	96,541
Accrued income tax, net	—	4,936
Regulatory liabilities, current	10,727	13,628
Notes payable	82,500	277,000
Current maturities of long-term debt	—	103,973
Total current liabilities	378,394	734,889
Long-term debt, net of current maturities	1,396,948	938,877
Deferred credits and other liabilities:		
Deferred income tax liabilities, net, non-current	432,287	385,908
Derivative liabilities, non-current	5,614	16,941
Regulatory liabilities, non-current	109,429	127,656
Benefit plan liabilities	111,479	167,397
Other deferred credits and other liabilities	133,279	125,294
Total deferred credits and other liabilities	792,088	823,196
Commitments and contingencies (See Notes 5, 6, 7, 8, 13, 17, and 19)		
Stockholders' equity:		
Common stock $1 par value; 100,000,000 shares authorized; issued: 44,550,239 and 44,278,189 shares, respectively	44,550	44,278
Additional paid-in capital	742,344	733,095
Retained earnings	540,244	492,869
Treasury stock at cost - 50,877 and 71,782 shares, respectively	(1,968)	(2,245)
Accumulated other comprehensive income (loss)	(17,422)	(35,488)
Total stockholders' equity	1,307,748	1,232,509
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$3,875,178	$3,729,471

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

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended	Dec. 31, 2013	Dec. 31, 2012	Dec. 31, 2011
	(in thousands)		
Operating activities:			
Net income available for common stock	$114,962	$81,528	$49,730
(Income) loss from discontinued operations, net of tax	884	6,977	(9,365)
Income (loss) from continuing operations	115,846	88,505	40,365
Adjustments to reconcile income (loss) from continuing operations to net cash provided by operating activities:			
Depreciation, depletion and amortization	141,217	154,632	135,591
Deferred financing cost amortization	6,763	5,555	5,655
Impairment of long-lived assets	—	26,868	—
Gain on sale of operating assets	—	(29,129)	—
Stock compensation	12,595	8,271	5,643
Unrealized (gain) loss on interest rate swaps, net	(30,169)	(1,882)	42,010
Deferred income taxes	63,784	39,716	33,600
Employee benefit plans	22,194	20,973	14,586
Other adjustments, net	9,826	4,929	(5,799)
Change in certain operating assets and liabilities:			
Materials, supplies and fuel	(5,770)	6,343	(21,385)
Accounts receivable, unbilled revenues and other current assets	(13,921)	13,739	22,290
Accounts payable and other current liabilities	15,336	(10,713)	(31,091)
Contributions to defined benefit pension plans	(12,500)	(25,350)	(11,050)
Other operating activities, net	312	(6,670)	(13,721)
Net cash provided by operating activities of continuing operations	325,513	295,787	216,694
Net cash provided by (used in) operating activities of discontinued operations	(884)	21,184	7,010
Net cash provided by operating activities	324,629	316,971	223,704
Investing activities:			
Property, plant and equipment additions	(354,749)	(349,129)	(440,698)
Proceeds from sale of assets	—	253,791	583
Other investing activities	5,471	(180)	(4,533)
Net cash provided by (used in) investing activities of continuing operations	(349,278)	(95,518)	(444,648)
Proceeds from sale of business operations	—	107,511	—
Net cash provided by (used in) investing activities of discontinued operations	—	(824)	(2,359)
Net cash provided by (used in) investing activities	(349,278)	11,169	(447,007)
Financing activities:			
Dividends paid on common stock	(67,587)	(65,262)	(59,202)
Common stock issued	4,354	4,726	123,041
Short-term borrowings - issuances	337,650	203,753	1,017,300
Short-term borrowings - repayments	(532,150)	(271,753)	(821,300)
Long-term debt - issuance	800,000	—	—
Long-term debt - repayments	(445,906)	(240,077)	(8,382)
De-designated interest rate swap settlement	(63,939)	—	—

Other financing activities	(15,394)	(2,833)	(1,666)
Net cash provided by (used in) financing activities of continuing operations	17,028	(371,446)	249,791
Net cash provided by (used in) financing activities of discontinued operations	—	—	(158)
Net cash provided by (used in) financing activities	17,028	(371,446)	249,633
Net change in cash and cash equivalents	(7,621)	(43,306)	26,330
Cash and cash equivalents beginning of year *	15,462	58,768	32,438
Cash and cash equivalents end of year *	$7,841	$15,462	$58,768

* Cash and cash equivalents include cash of discontinued operations of $37 million and $16 million at Dec. 31, 2011 and 2010 respectively.

See Note 16 for supplemental disclosure of cash flow information.

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

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

(in thousands except share and per share amounts)	Common Stock Shares	Common Stock Value	Treasury Stock Shares	Treasury Stock Value	Additional Paid in Capital	Retained Earnings	AOCI	Total
Balance at Dec. 31, 2010	39,280,048	$39,280	10,962	$(309)	$598,805	$486,075	$(23,581)	$1,100,270
Net income (loss) available for common stock	—	—	—	—	—	49,730	—	49,730
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	(9,297)	(9,297)
Dividends on common stock	—	—	—	—	—	(59,202)	—	(59,202)
Share-based compensation	161,424	161	21,804	(661)	5,576	—	—	5,076
Tax effect of share-based compensation	—	—	—	—	(28)	—	—	(28)
Issuance of common stock	4,413,519	4,414	—	—	115,216	—	—	119,630
Dividend reinvestment and stock purchase plan	102,511	103	—	—	3,099	—	—	3,202
Other stock transactions	—	—	—	—	(45)	—	—	(45)
Balance at Dec. 31, 2011	43,957,502	$43,958	32,766	$(970)	$722,623	$476,603	$(32,878)	$1,209,336
Net income (loss) available for common stock	—	—	—	—	—	81,528	—	81,528
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	(2,610)	(2,610)
Dividends on common stock	—	—	—	—	—	(65,262)	—	(65,262)
Share-based compensation	219,946	220	39,016	(1,275)	7,095	—	—	6,040
Tax effect of share-based compensation	—	—	—	—	117	—	—	117
Dividend reinvestment and stock purchase plan	100,741	100	—	—	3,282	—	—	3,382
Other stock transactions	—	—	—	—	(22)	—	—	(22)
Balance at Dec. 31, 2012	44,278,189	$44,278	71,782	$(2,245)	$733,095	$492,869	$(35,488)	$1,232,509
Net income (loss) available for common stock	—	—	—	—	—	114,962	—	114,962
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	18,066	18,066
Dividends on common stock	—	—	—	—	—	(67,587)	—	(67,587)
Share-based compensation	190,172	190	(20,905)	277	5,400	—	—	5,867
Tax effect of share-based compensation	—	—	—	—	410	—	—	410
Dividend reinvestment and stock purchase plan	66,878	67	—	—	3,062	—	—	3,129
Other stock transactions	15,000	15	—	—	377	—	—	392
Balance at Dec. 31, 2013	44,550,239	$44,550	50,877	$(1,968)	$742,344	$540,244	$(17,422)	$1,307,748

Dividends per share paid were $1.52, $1.48 and $1.46 for the years ended Dec. 31, 2013, 2012 and 2011, respectively.

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

BLACK HILLS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Dec. 31, 2013, 2012 and 2011

(1) BUSINESS DESCRIPTION AND SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Corporation is a diversified energy company headquartered in Rapid City, South Dakota. We are a holding company that, through our subsidiaries, operates in two primary business groups: Utilities and Non-regulated Energy.

The Utilities Group includes our Electric Utilities and Gas Utilities segments. Electric Utilities include the operating results of the regulated electric utility operations of Black Hills Power and Colorado Electric, and the electric and natural gas utility operations of Cheyenne Light, which supply regulated electric utility services to areas in South Dakota, Wyoming, Colorado and Montana and natural gas utility services to Cheyenne, Wyo. and vicinity. Gas Utilities consist of the operating results of the regulated natural gas utility operations of Colorado Gas, Nebraska Gas, Iowa Gas, and Kansas Gas.

The Non-regulated Energy Group includes our Power Generation, Coal Mining and Oil and Gas segments. Power Generation, which is conducted through Black Hills Electric Generation and its subsidiaries, engages in independent power generation activities in Wyoming and Colorado. Coal Mining, which is conducted through WRDC, engages in coal mining activities located near Gillette, Wyo. Oil and Gas, which is conducted through BHEP and its subsidiaries, engages in crude oil and natural gas exploration and production activities in Colorado, Louisiana, Montana, Oklahoma, New Mexico, North Dakota, Wyoming, Texas and California. These businesses are aggregated for reporting purposes as Non-regulated Energy.

On Feb. 29, 2012, we sold Enserco, our Energy Marketing segment, which resulted in this segment being classified as discontinued operations. See Note 21 for additional information.

For further descriptions of our reportable business segments, see Note 4.

Use of Estimates and Basis of Presentation

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Changes in facts and circumstances or additional information may result in revised estimates and actual results could differ materially from those estimates.

Principles of Consolidation

The consolidated financial statements include the accounts of Black Hills Corporation and its wholly-owned and majority-owned and controlled subsidiaries. Investment in non-controlled entities over which we have the ability to exercise significant influence over operating and financial policies are accounted for using the equity method of accounting. In applying the equity method of accounting, the investments are initially recognized at cost, and subsequently adjusted for our proportionate share of earnings and losses and distributions. Under this method, a proportionate share of pretax income is recorded as Equity earnings (loss) of unconsolidated subsidiaries. All inter-company balances and transactions have been eliminated in consolidation. For additional information on inter-company revenues, see Note 4.

Our Consolidated Statements of Income include operating activity of acquired companies beginning with their acquisition date. We use the proportionate consolidation method to account for our working interests in oil and gas properties and for our ownership interest in any jointly-owned electric utility generating facility, wind project or transmission tie and the BHEP gas processing plant. See Note 3 for additional information.

As a result of the sale of our Energy Marketing segment, amounts associated with this segment have been reclassified as discontinued operations on the accompanying Consolidated Financial Statements. See Note 21 for additional information.

Cash and Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Equivalents

The Black Hills Wyoming project financing required that we maintain cash accounts for various specified purposes. We did not readily have access to these accounts and could only withdraw funds upon meeting certain requirements. Therefore, we had classified these amounts as restricted cash. This project financing was repaid in 2013.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable for our Utilities Group primarily consists of sales to residential, commercial, industrial, municipal and other customers, all of which do not bear interest. These accounts receivable are stated at billed and unbilled amounts net of write-offs and allowance for doubtful accounts. Accounts receivable for our Non-regulated Energy Group consists of amounts due from sales of coal, crude oil and natural gas, electric energy and capacity.
We maintain an allowance for doubtful accounts which reflects our estimate of uncollectible trade receivables. We regularly review our trade receivable allowance by considering such factors as historical experience, credit worthiness, the age of the receivable balances and current economic conditions that may affect collectibility.

In specific cases where we are aware of a customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be affected. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of commodity prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible or the time allowed for dispute under the contract has expired.
We utilize master netting agreements which consist of an agreement between two parties who have multiple contracts with each other that provide for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim, or the obligation to return, cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty.

Following is a summary of accounts receivable as of Dec. 31 (in thousands):

2013	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$52,437	$23,823	$(666)	$75,594
Gas Utilities	49,162	41,195	(558)	89,799
Power Generation	1,722	—	—	1,722
Coal Mining	1,711	—	—	1,711
Oil and Gas	8,156	—	(13)	8,143
Corporate	604	—	—	604
Total	$113,792	$65,018	$(1,237)	$177,573

2012	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$54,482	$23,843	$(527)	$77,798
Gas Utilities	31,495	39,962	(222)	71,235
Power Generation	16	—	—	16
Coal Mining	2,247	—	—	2,247
Oil and Gas	11,622	—	(19)	11,603
Corporate	799	—	—	799
Total	$100,661	$63,805	$(768)	$163,698

Revenue Recognition

Revenue is recognized when there is persuasive evidence of an arrangement with a fixed or determinable price and delivery has occurred or services have been rendered. Sales tax collected from our customers is recorded on a net basis (excluded from Revenue).

Utility revenues are based on authorized rates approved by the state regulatory agencies and the FERC. Revenues related to the sale, transmission and distribution of energy, and delivery of service are generally recorded when service is rendered or energy is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, our utilities accrue an estimate of the revenue since the latest billing. This estimate is calculated based upon several factors including billings through the last billing cycle in a month, and prices in effect in our jurisdictions. Each month the estimated unbilled revenue amounts are trued-up and recorded in Accounts receivable, net on the accompanying Consolidated Balance Sheets.

For long-term non-regulated power sales agreements, revenue is recognized either in accordance with accounting standards for revenue recognition, or in accordance with accounting standards for leases, as appropriate. Under accounting standards for revenue recognition, revenue is generally recognized as the lesser of the amount billed or the average rate expected over the life of the agreement.

Natural gas and crude oil sales are recognized when the products are sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred and collectibility of the revenue is reasonably assured. Our Oil and Gas segment records its share of revenues based on production volumes and contracted sales prices. The sales price for natural gas, crude oil, condensate and NGLs is adjusted for transportation costs and other related deductions when applicable. The transportation costs and other deductions are based on contractual or historical data and do not require significant judgment.

Materials, Supplies and Fuel

The following amounts by major classification are included in Materials, supplies and fuel on the accompanying Consolidated Balance Sheets as of (in thousands):

	Dec. 31, 2013	Dec. 31, 2012
Materials and supplies	$50,196	$43,397
Fuel - Electric Utilities	6,213	8,589
Natural gas in storage held for distribution	32,069	25,657
Total materials, supplies and fuel	$88,478	$77,643

Materials and supplies represent parts and supplies for all of our business segments. Fuel - Electric Utilities represents oil, gas, and coal on hand used to produce power. Natural gas in storage primarily represents gas purchased for use by our gas customers. All of our Materials, supplies and fuel are valued using weighted-average cost. The value of our natural gas in storage fluctuates with seasonal volume requirements of our business and the commodity price of natural gas.

Property, Plant and Equipment

Additions to property, plant and equipment are recorded at cost. Included in the cost of regulated construction projects is AFUDC, which represents the approximate composite cost of borrowed funds and a return on equity used to finance a regulated utility project. We also capitalize interest, when applicable, on undeveloped leasehold costs and certain non-regulated construction projects. In addition, asset retirement costs associated with tangible long-lived regulated utility assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived regulated utility assets in the period incurred. The amounts capitalized are included in Property, plant and equipment on the accompanying Consolidated Balance Sheets.

The cost of regulated utility property, plant and equipment retired, or otherwise disposed of in the ordinary course of business, less salvage plus cost of removal, is charged to accumulated depreciation. Removal costs associated with non-legal obligations related to our regulated properties are reclassified from accumulated depreciation and reflected as regulatory liabilities. Retirement or disposal of all other assets, except for crude oil and natural gas properties as described below, result in gains or losses recognized as a component of operating income. Ordinary repairs and maintenance of property, except as allowed under rate regulations, are charged to operations as incurred.

Depreciation provisions for property, plant and equipment are generally computed on a straight-line basis based on the applicable estimated service life of the various class of property. Capitalized coal mining costs and coal leases are amortized on a unit-of-production method based on volumes produced and estimated reserves. For certain non-utility power plant components, a unit-of-production methodology based on plant hours run is used.

Oil and Gas Operations

We account for our oil and gas activities under the full cost method. Under the full cost method, costs related to acquisition, exploration and estimated future expenditures to be incurred in developing proved reserves as well as estimated reclamation and abandonment costs, net of estimated salvage values are capitalized. These costs are amortized using a unit-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonment of properties, are typically treated as adjustments to the cost of the properties with no gain or loss recognized. However, we recognized a gain on the sale of a majority of our Williston Basin assets in 2012. See Note 21 for further discussion.

Costs directly associated with unproved properties and major development projects, if any, are excluded from the costs to be amortized. These excluded costs are subsequently included within the costs to be amortized when it is determined whether or not proved reserves can be assigned to the properties. The properties excluded from the costs to be amortized are assessed for impairment at least annually and any amount of impairment is added to the costs to be amortized. These costs are generally expected to be included in costs to be amortized within the term of the underlying lease agreement which varies in length.

Under the full cost method, net capitalized costs are subject to a ceiling test which limits these costs to the present value of future net cash flows discounted at an SEC required rate, net of related tax effects, plus the lower of cost or fair value of unproved properties included in the net capitalized costs. Future net cash flows are estimated based on SEC-defined end-of-period commodity prices adjusted for contracted price changes and held constant for the life of the reserves. An average price is calculated using the price at the first day of each month for each of the preceding 12 months. If the net capitalized costs exceed the full cost “ceiling” at period end, a permanent non-cash write-down would be charged to earnings in that period. As a result of lower natural gas prices, we recorded a non-cash ceiling test impairment of oil and gas long-lived assets included in the Oil and Gas segment in 2012. No ceiling test write-down was recorded in 2013 or 2011. See Note 12 for additional information.

The SEC definition of “reliable technology” permits the use of any reliable technology to establish reserve volumes in addition to those established by production and flow test data. This definition allows, but does not require us, to calculate PUDs to be booked at more than one location away from a producing well. We elected to include PUDs of only one location away from a producing well in our volume reserve estimate. See information on our oil and gas drilling activities in Note 20.

Companies are permitted but not required to disclose probable and possible reserves. We have elected not to report on these additional reserve categories.

Goodwill and Intangible Assets

Goodwill and intangible assets with indefinite lives are not amortized but the carrying values are reviewed upon an indicator of impairment or at least annually. Intangible assets with a finite life continue to be amortized over their estimated useful lives. We perform this annual review of goodwill and indefinite lived intangible assets as of Nov. 30 each year (or more frequently if impairment indicators arise).

We performed our annual goodwill impairment tests as of Nov. 30, 2013. We estimated the fair value of the goodwill using discounted cash flow methodology, EBITDA multiple method, and an analysis of comparable transactions. This analysis required the input of several critical assumptions, including future growth rates, cash flow projections, operating cost escalation rates, rates of return, a risk-adjusted discount rate, timing and level of success in regulatory rate proceedings, the cost of debt and equity capital, and long-term earnings and merger multiples for comparable companies.

Goodwill at our Electric and Gas Utilities primarily arose from the acquisition of one regulated electric and four regulated gas utilities in the Aquila Transaction. This goodwill from the Aquila Transaction was allocated approximately $246 million, or 72 percent, to Colorado Electric and $94 million, or 28 percent, to the Gas Utilities. We believe that the goodwill amount reflects the value of the relatively stable, long-lived cash flows of the regulated gas utility business, considering the regulatory environment and market growth potential and the long-lived cash flow and rate base growth opportunities at our electric utility in Colorado. Goodwill balances were as follows (in thousands):

	Electric Utilities	Gas Utilities	Power Generation	Total
Ending balance at Dec. 31, 2011	$250,487	$94,144	$8,765	$353,396
Additions (adjustments)	—	—	—	—
Ending balance at Dec. 31, 2012	$250,487	$94,144	$8,765	$353,396
Additions (adjustments)	—	—	—	—
Ending balance at Dec. 31, 2013	$250,487	$94,144	$8,765	$353,396

Our intangible assets represent easements, rights-of-way and trademarks and are amortized using a straight-line method based on estimated useful lives. The finite lived intangible assets are currently being amortized over 20 years. Changes to intangible assets for the years ended Dec. 31, were as follows (in thousands):

	2013	2012	2011
Intangible assets, net, beginning balance	$3,620	$3,843	$4,069
Additions (adjustments)	—	—	—
Amortization expense *	(223)	(223)	(226)
Intangible assets, net, ending balance	$3,397	$3,620	$3,843

* Amortization expense for existing intangible assets is expected to be $0.2 million for each year of the next five years.

Asset Retirement Obligations

Accounting standards for asset retirement obligations associated with long-lived assets require that the present value of retirement costs for which we have a legal obligation be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The associated ARO accretion expense for our non-regulated operations is included within Depreciation, depletion and amortization on the accompanying Consolidated Statements of Income. The accounting for the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset.

We initially record liabilities for the present value of retirement costs for which we have a legal obligation, with an equivalent amount added to the asset cost. The asset is then depreciated or depleted over the appropriate useful life and the liability is accreted over time by applying an interest method of allocation. Any difference in the actual cost of the settlement of the liability and the recorded amount is recognized as a gain or loss in the results of operations at the time of settlement for our non-regulated operations, other than Oil and Gas. For the Oil and Gas segment, differences in the settlement of the liability and the recorded amount are generally reflected as adjustments to the capitalized cost of oil and gas properties and depleted pursuant to our use of the full cost method. Additional information is included in Note 7.

Fair Value Measurements

Derivative Financial Instruments

Assets and liabilities are classified and disclosed in one of the following fair value categories:

Level 1 — Unadjusted quoted prices available in active markets that are accessible at the measurement date for identical unrestricted assets or liabilities. This level primarily consists of financial instruments such as exchange-traded securities or listed derivatives.

Level 2 — Pricing inputs include quoted prices for identical or similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 — Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs reflect management's best estimate of fair value using its own assumptions about the assumptions a market participant would use in pricing the asset or liability.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels. We record transfers, if necessary, between levels at the end of the reporting period for all of our financial instruments.

Transfers into Level 3, if any, occur when significant inputs used to value the derivative instruments become less observable such as a significant decrease in the frequency and volume in which the instrument is traded, negatively impacting the availability of observable pricing inputs. Transfers out of Level 3, if any, occur when the significant inputs become more observable such as the time between the valuation date and the delivery date of a transaction becomes shorter, positively impacting the availability of observable pricing inputs.

Valuation Methodologies for Derivatives

Oil and Gas Segment:

- The commodity option contracts for the Oil and Gas segment are valued under the market approach and include calls and puts. Fair value was derived using quoted prices from third party brokers for similar instruments as to quantity and timing. The prices are then validated through third party sources and therefore support Level 2 disclosure.

- The commodity basis swaps for the Oil and Gas segment are valued under the market approach using the instrument's current forward price strip hedged for the same quantity and date and discounted based on the three-month LIBOR. We utilize observable inputs which support Level 2 disclosure.

Utilities Segment:

- The commodity contracts for the Utilities, valued using the market approach, include exchange-traded futures, options and basis swaps (Level 2) and OTC basis swaps (Level 3) for natural gas contracts. For Level 2 assets and liabilities, fair value was derived using broker quotes validated by the Chicago Mercantile Exchange pricing for similar instruments. For Level 3 assets and liabilities, fair value was derived using average price quotes from the OTC contract broker and an independent third party market participant since these instruments are not traded on an exchange.

Corporate Segment:

- The interest rate swaps are valued using the market valuation approach. We establish fair value by obtaining price quotes directly from the counterparty which are based on the floating three-month LIBOR curve for the term of the contract. The fair value obtained from the counterparty is then validated by utilizing a nationally recognized service that obtains observable inputs to compute fair value for the same instrument. In addition, the fair value for the interest rate swap derivatives includes a CVA component. The CVA considers the fair value of the interest rate swap and the probability of default based on the life of the contract. For the probability of a default component, we utilize observable inputs supporting Level 2 disclosure by using our credit default spread, if available, or a generic credit default spread curve that takes into account our credit ratings.

Additional information is included in Note 9.

Derivatives and Hedging Activities

The accounting standards for derivatives and hedging require that derivative instruments be recorded on the balance sheet as either an asset or liability measured at its fair value, and that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met and designated accordingly. Each Consolidated Balance Sheet reflects the offsetting of net derivative positions with fair value amounts for cash collateral with the same counterparty when a legal right of offset exists.

Accounting standards for derivatives and hedging require that the unrealized gains or losses on a derivative instrument designated and qualifying as a fair value hedging instrument as well as the offsetting unrealized loss or gain on the hedged item attributable to the hedged risk be recognized currently in earnings in the same accounting period. Conversely, the effective portion of the unrealized gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument must be reported as a component of other comprehensive income and be reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument, if any, is recognized currently in earnings.

We utilize master netting agreements which consist of an agreement between two parties who have multiple contracts with each other that provide for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim, or the obligation to return, cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty.

Deferred Financing Costs

Deferred financing costs are amortized using the effective interest method over the estimated useful life of the related debt.

Development Costs

According to accounting standards for business combinations, we expense, when incurred, development and acquisition costs associated with corporate development activities prior to acquiring or beginning construction of a project. Expensed development costs are included in Other operating expenses on the accompanying Consolidated Statements of Income.

Legal Costs

Litigation liabilities, including potential settlements, are recorded when it is both probable that a liability or settlement has been incurred, and the amount can be reasonably estimated. Legal costs related to ongoing litigation are expensed as incurred.

When a range of the probable loss exists and no amount within the range is a better estimate than any other amount, we record a loss contingency at the minimum amount in the range. If the loss contingency at issue is not both probable and reasonably estimable, we do not establish an accrual and the matter will continue to be monitored for any developments that would make the loss contingency both probable and reasonably estimable.

Regulatory Accounting

Our Utilities Group follows accounting standards for regulated operations and reflects the effects of the numerous rate-making principles followed by the various state and federal agencies regulating the utilities. The accounting policies followed are generally subject to the Uniform System of Accounts of the FERC. These accounting policies differ in some respects from those used by our non-regulated businesses. If rate recovery becomes unlikely or uncertain due to competition or regulatory action, these accounting standards may no longer apply which would require these net assets to be charged to current income or OCI. Our regulatory assets represent amounts for which we will recover the cost, but generally are not allowed a return, except as described below. In the event we determine that our regulated net assets no longer meet the criteria for following accounting standards for regulated operations, the accounting impact to us could be an extraordinary non-cash charge to operations, which could be material.

We had the following regulatory assets and liabilities (in thousands):

	Maximum Amortization (in years)	As of Dec. 31, 2013	As of Dec. 31, 2012
Regulatory assets			
Deferred energy and fuel cost adjustments - current [(a)]	1	$16,775	$16,005
Deferred gas cost adjustments and gas price derivatives [(a)]	7	12,366	20,741
AFUDC [(b)]	45	12,315	12,416
Employee benefit plans [(c)]	13	67,059	115,521
Environmental [(a)]	subject to approval	1,800	1,792
Asset retirement obligations [(a)]	44	3,266	3,247
Bond issue cost [(a)]	24	3,419	3,561
Renewable energy standard adjustment [(a)]	5	14,186	19,484
Flow through accounting [(d)]	35	20,916	16,620
Other regulatory assets [(a)]	15	10,546	10,006
		$162,648	$219,393
Regulatory liabilities			
Deferred energy and gas costs [(a)]	1	$11,708	$21,091
Employee benefit plans [(e)]	13	34,431	59,362
Cost of removal [(a)]	44	64,970	53,526
Other regulatory liabilities [(f)]	25	9,047	7,305
		$120,156	$141,284

(a) Recovery of costs, but not allowed a rate of return.
(b) In addition to recovery of costs, we are allowed a rate of return.
(c) In addition to recovery of costs, we are allowed a return on approximately $25 million.
(d) In addition to recovery of costs, we are allowed a return on approximately $5.4 million.
(e) Approximately $13 million is included in our rate base calculations as a reduction to rate base.
(f) Approximately $2.6 million is included in our rate base calculations as a reduction to rate base.

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

Deferred Energy and Fuel Cost Adjustments - Deferred energy and fuel cost adjustments represent the cost of electricity delivered to our electric utility customers that is either higher or lower than the current rates and will be recovered or refunded in future rates. Deferred energy and fuel cost adjustments are recorded and recovered or amortized as approved by the appropriate state commission.

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Deferred Gas Cost Adjustment and Gas Price Derivatives - Our regulated gas utilities have GCA provisions that allow them to pass the cost of gas on to their customers. In addition, as allowed or required by state utility commissions, we have entered into certain exchange-traded natural gas futures and options to reduce our customers' underlying exposure to fluctuations in gas prices. The GCA is based on forecasts of the upcoming gas costs and recovery or refund of prior under-recovered or over-recovered costs. To the extent that gas costs are under-recovered or over-recovered, they are recorded as a regulatory asset or liability, respectively. Our Gas Utilities file periodic estimates of future gas costs based on market forecasts with state utility commissions.

AFUDC - The equity component of AFUDC is considered a permanent difference for tax purposes with the tax benefit being flowed through to customers as prescribed or allowed by regulators. If, based on a regulator's action, it is probable the utility will recover the future increase in taxes payable represented by this flow-through treatment through a rate revenue increase, a regulatory asset is recognized. This regulatory asset is a temporary difference for which a deferred tax liability must be recognized. Accounting standards for income taxes specifically address AFUDC-equity, and require a gross-up of such amounts to reflect the revenue requirement associated with a rate-regulated environment.

Employee Benefit Plans - Employee benefit plans include the unrecognized prior service costs and net actuarial loss associated with our defined benefit pension plans and post-retirement benefit plans in regulatory assets rather than in accumulated other comprehensive income, including costs being amortized from the Aquila Transaction.

Environmental - Environmental is associated with manufactured gas plant sites. The amortization of this asset is first offset by recognition of insurance proceeds and settlements with other third parties. Any remaining recovery will be requested in future rate filings. Recovery has not yet been approved by the applicable commission or board and therefore, the recovery period is unknown.

Asset Retirement Obligations - Asset retirement obligations represent the estimated recoverable costs for legal obligations associated with the retirement of a tangible long-lived asset. See Note 7 for additional details.

Bond Issue Costs - Bond issue costs are recovered over the remaining life of the original issue or, if refinanced, over the life of the new issue.

Renewable Energy Standard Adjustment - The renewable energy standard adjustment is associated with incentives for our Colorado Electric customers to install renewable energy equipment at their location. These incentives are recovered over time with an additional rider charged on customers' bills.

Flow-Through Accounting - Under flow-through accounting, the income tax effects of certain tax items are reflected in our cost of service for the customer in the year in which the tax benefits are realized and result in lower utility rates. This regulatory treatment was applied to the tax benefit generated by repair costs that were previously capitalized for tax purposes in a rate case settlement that was reached with respect to Black Hills Power in 2010. In this instance, the agreed upon rate increase was less than it would have been absent the flow-through treatment. A regulatory asset was established to reflect that future increases in income taxes payable will be recovered from customers as the temporary differences reverse.

Regulatory liabilities represent items we expect to refund to customers through probable future decreases in rates.

Deferred Energy and Gas Costs - Deferred energy costs and gas costs related to over-recovery of purchased power, transmission and natural gas costs.

Employee Benefit Plans - Employee benefit plans represent the cumulative excess of pension and retiree healthcare costs recovered in rates over pension expense recorded in accordance with accounting standards for compensation - retirement benefits. In addition, this regulatory liability includes the income tax effect of the adjustment required under accounting for compensation - defined benefit plans, to record the full pension and post-retirement benefit obligations. Such income tax effect has been grossed-up to account for the revenue requirement aspect of a rate regulated environment.

Cost of Removal - Cost of removal represents the estimated cumulative net provisions for future removal costs included in depreciation expense for which there is no legal obligation for removal.

Income Taxes

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

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

It is our policy to apply the flow-through method of accounting for investment tax credits as allowed by our rate-regulated jurisdictions. Under the flow-through method, investment tax credits are reflected in net income as a reduction to income tax expense in the year they qualify. Another acceptable accounting method and an exception to this general policy currently in our regulated businesses is to apply the deferral method whereby the credit is amortized as a reduction of income tax expense over the useful lives of the related property.

We recognize interest income or interest expense and penalties related to income tax matters in Income tax (expense) benefit on the Consolidated Statements of Income.

We account for uncertainty in income taxes recognized in the financial statements in accordance with accounting standards for income taxes. The unrecognized tax benefit is classified in Other deferred credits and other liabilities on the accompanying Consolidated Balance Sheets. See Note 14 for additional information.

Earnings per Share of Common Stock

Basic earnings per share from continuing and discontinued operations is computed by dividing Income (loss) from continuing or discontinued operations by the weighted average number of common shares outstanding during each year. Diluted earnings per share is computed by including all dilutive common shares outstanding during each year. Diluted common shares are primarily due to outstanding stock options, restricted stock and performance shares under our equity compensation plans.

A reconciliation of share amounts used to compute earnings (loss) per share is as follows (in thousands):

	Dec. 31, 2013	Dec. 31, 2012	Dec. 31, 2011
Income (loss) from continuing operations	$115,846	$88,505	$40,365
Weighted average shares - basic	44,163	43,820	39,864
Dilutive effect of:			
Equity compensation	256	250	214
Other	—	3	3
Weighted average shares - diluted	44,419	44,073	40,081
Income (loss) from continuing operations, per share - Diluted	$2.61	$2.01	$1.01

The following outstanding securities were not included in the computation of diluted earnings per share as their effect would have been anti-dilutive (in thousands):

	Dec. 31, 2013	Dec. 31, 2012	Dec. 31, 2011
Equity compensation	22	163	141
Other	—	—	—
Anti-dilutive shares excluded from computation of earnings (loss) per share	22	163	141

Discontinued Operations

Assets of discontinued operations are recorded at the lower of their carrying amount or fair value less cost to sell. Additionally, in accordance with GAAP, indirect corporate costs previously allocated to a disposal group cannot be reclassified to discontinued operations. Assets of discontinued operations and Liabilities of discontinued operations on the accompanying Consolidated Balance Sheets included the assets and liabilities of Enserco Energy Inc. See Note 21 for additional information.

Recently Adopted Accounting Standards

Inclusion of the Fed Funds Effective Swap Rate as a Benchmark Interest Rate for Hedge Accounting Purposes, ASU 2013-10

In July 2013, the FASB issued an amendment to accounting for derivatives and hedges to permit the Fed Funds Effective Swap Rate to be used as a U.S. benchmark interest rate for hedge accounting purposes effective for new or re-designated hedging relationships entered into on or after July 17, 2013. The amendment also removed the restriction on using different benchmark rates for similar hedges. The adoption had no impact on our consolidated financial position, results of operations or cash flows.

Balance Sheet: Disclosure about Offsetting Assets and Liabilities, ASU 2011-11, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities, ASU 2013-01

In December 2011, the FASB issued revised accounting guidance to amend ASC 210, Balance Sheet, related to the existing disclosure requirements for offsetting financial assets and liabilities to enhance current disclosures, as well as to improve comparability of balance sheets prepared under GAAP and IFRS. The revised disclosure guidance affects all companies that have financial instruments and derivative instruments that are either offset in the balance sheet (i.e., presented on a net basis) or subject to an enforceable master netting and/or similar arrangement. In addition, the revised guidance requires that certain enhanced quantitative and qualitative disclosures are made with respect to a company's netting arrangements and/or rights of offset associated with its financial instruments and/or derivative instruments. The revised disclosure guidance was effective on a retrospective basis for interim and annual periods beginning Jan. 1, 2013. The adoption of this standard did not have an impact on our financial position, results of operations or cash flows.

Other Comprehensive Income: Presentation of Comprehensive Income, ASU 2011-05 and Deferral of the Effective Date for Amendments to the Presentation of Reclassification of Items Out of Accumulated Other Comprehensive Income in ASU 2011-05 and ASU 2011-12

FASB issued an accounting standards update amending accounting standards for comprehensive income to improve the comparability, consistency and transparency of reporting. It amends existing guidance by allowing only two options for presenting the components of net income and other comprehensive income: (1) in a single continuous financial statement, statement of comprehensive income or (2) in two separate but consecutive financial statements, consisting of an income statement followed by a separate statement of other comprehensive income. Also, items that are reclassified from other comprehensive income to net income must be presented on the face of the financial statements. ASU 2011-05 requires retrospective application, and it was effective for fiscal years, and interim periods within those years, beginning after Dec. 15, 2011, with early adoption permitted. In Dec. 2011, FASB issued ASU 2011-12. ASU 2011-12 indefinitely deferred the provisions of ASU 2011-05 requiring the presentation of reclassification adjustments on the face of the financial statements for items reclassified from other comprehensive income to net income. Ultimately FASB chose not to reinstate the reclassification adjustment requirements in ASU 2011-05 but instead issued ASU 2013-02 in February 2013. The adoption of this standard did not have an impact on our financial position, results of operations or cash flows.

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income, ASU 2013-02

In February 2013, the FASB issued new disclosure requirements for items reclassified out of AOCI to expand the disclosure requirements in ASC 220, Comprehensive Income, for presentation of changes in AOCI. ASU 2013-02 requires disclosure (1) of changes in components of other comprehensive income, (2) for items reclassified out of AOCI and into net income in their entirety, the effect of the reclassification on each affected net income line item and (3) of cross references to other disclosures that provide additional detail for components of other comprehensive income that are not reclassified in their entirety to net income. Disclosures are required either on the face of the statements of income or as a separate disclosure in the notes to the financial statements. The new disclosure requirements are effective for interim and annual periods beginning after Dec. 15, 2012. The adoption of this standard did not have an impact on our financial position, results of operations or cash flows.

Dodd-Frank Wall Street Reform and Consumer Protection Act, SEC Final Rule No. 33-9286, 33-9338, 34-67717, and 34-67716

In July 2010, the President of the United States signed into law comprehensive financial reform legislation under Dodd-Frank. Title VII of Dodd-Frank effectively regulates many derivative transactions in the United States that were previously unregulated. 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.

In August 2012, under Dodd-Frank, the SEC adopted new requirements for companies that manufacture or contract to manufacture products that contain certain minerals and metals, known as conflict minerals. The final rule requires all issuers that file reports with the SEC and use conflict minerals to report supply chain and sourcing information on an annual basis. We completed due diligence efforts in 2013, and we do not believe that our products contain conflict minerals as defined by the rule.

Recently Issued Accounting Pronouncements and Legislation

Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists, ASU 2013-11

In July 2013, the FASB issued an amendment to accounting for income taxes which provides guidance on financial statement presentation of an unrecognized tax benefit when an NOL carryforward, a similar tax loss, or a tax credit carryforward exists. The objective in issuing this amendment is to eliminate diversity in practice resulting from a lack of guidance on this topic in current GAAP. Under the amendment, an entity must present an unrecognized tax benefit, or a portion of an unrecognized tax benefit, in the financial statements as a reduction to a deferred tax asset for an NOL carryforward, a similar tax loss, or a tax credit carryforward except under certain conditions. The amendment is effective for fiscal years beginning after Dec. 15, 2013, and interim periods within those years and should be applied to all unrecognized tax benefits that exist as of the effective date. The adoption of this standard is not expected to have an impact on our financial position, results of operations or cash flows.

Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date, ASU 2013-04

In March 2013, the FASB issued new disclosure requirements for recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements including disclosure of the nature and amount of the obligations. The new disclosure requirements are effective for interim and annual periods beginning after Dec. 15, 2013. The amendment requires enhanced disclosures in the notes to financial statements, but will not have any other impact on our consolidated financial statements.

Final Tangible Personal Property Regulations, IRS Treasury Decision 9636

In September 2013, the U.S. Treasury issued final regulations addressing the tax consequences associated with amounts paid to acquire, produce, or improve tangible property. The regulations have the effect of a change in law and as a result the impact should be taken into account in the period of adoption. In general, such regulations apply to tax years beginning on or after Jan. 1, 2014, with early adoption permitted. We expect that implementation of most, if not all, of the provisions of the final regulations in 2014. Procedural guidance is expected from IRS in early 2014 to facilitate implementation. Analysis performed to date indicates no material impact to our consolidated financial statements.

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(2) PROPERTY, PLANT AND EQUIPMENT

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

Utilities Group	2013		2012		Lives (in years)	
Electric Utilities	Property, Plant and Equipment	Weighted Average Useful Life (in years)	Property, Plant and Equipment	Weighted Average Useful Life (in years)	Minimum	Maximum
Electric plant:						
Production	$951,138	45	$959,636	45	25	65
Electric transmission	238,542	50	234,279	50	40	65
Electric distribution	666,589	44	631,654	44	15	65
Plant acquisition adjustment (a)	4,870	32	4,870	32	32	32
General	138,263	22	137,584	22	3	60
Capital lease - plant in service (b)	261,441	20	260,874	19	20	20
Total electric plant in service	$2,260,843		$2,228,897			
Construction work in progress	203,760		48,008			
Total electric plant	2,464,603		2,276,905			
Less accumulated depreciation and amortization	472,970		439,772			
Electric plant net of accumulated depreciation and amortization	$1,991,633		$1,837,133			

(a) The plant acquisition adjustment is included in rate base and is being recovered with 17 years remaining.

(b) Capital lease - plant in service represents the assets accounted for as a capital lease under the PPA between Colorado Electric and Black Hills Colorado IPP. The capital lease ends in conjunction with the expiration of the PPA on Dec. 31, 2031.

	2013		2012		Lives (in years)	
Gas Utilities	Property, Plant and Equipment	Weighted Average Useful Life (in years)	Property, Plant and Equipment	Weighted Average Useful Life (in years)	Minimum	Maximum
Gas plant:						
Production	$13	37	$13	37	37	37
Gas transmission	24,984	54	18,071	54	53	57
Gas distribution	507,318	46	474,998	46	41	56
General	85,841	19	68,856	19	16	22
Total gas plant in service	618,156		561,938			
Construction work in progress	9,417		6,305			
Total gas plant	627,573		568,243			
Less accumulated depreciation and amortization	84,679		68,530			
Gas plant net of accumulated depreciation and amortization	$542,894		$499,713			

2013						Lives (in years)		
Non-regulated Energy	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Power Generation	$143,026	$10,491	$153,517	$43,069	$110,448	36	2	40
Coal Mining	149,067	1,156	150,223	86,306	63,917	14	2	59
Oil and Gas	852,384	—	852,384	585,334	267,050	24	3	25
	$1,144,477	$11,647	$1,156,124	$714,709	$441,415			

2012						Lives (in years)		
Non-regulated Energy	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Power Generation	$139,396	$1,323	$140,719	$38,541	$ 102,178	35	2	40
Coal Mining	148,045	7,023	155,068	80,210	74,858	14	2	59
Oil and Gas	785,594	—	785,594	562,926	222,668	24	3	25
	$1,073,035	$8,346	$1,081,381	$681,677	$ 399,704			

2013						Lives (in years)		
	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization (a)	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Corporate	$5,498	$5,647	$11,145	$(3,210)	$14,355	6	2	30

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

2012						Lives (in years)		
	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization (a)	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Corporate	$368	$3,875	$4,243	$(1,956)	$6,199	6	2	30

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

(3) JOINTLY OWNED FACILITIES

Utility Plant

Our consolidated financial statements include our share of several jointly-owned utility facilities as described below. Our share of the facilities expenses are reflected in the appropriate categories of operating expenses in the Consolidated Statements of Income. Each owner of the facility is responsible for financing its investment in the jointly-owned facilities.

- Black Hills Power owns a 20 percent interest in the Wyodak Plant, a coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp owns the remaining ownership percentage and operates the Wyodak Plant. Black Hills Power receives its proportionate share of the Wyodak Plant's capacity and is committed to pay its proportionate share of its additions, replacements and operating and maintenance expenses. In addition to supplying Black Hills Power with coal for its share of the Wyodak Plant, our Coal Mining subsidiary, WRDC, supplies PacifiCorp's share of the coal to the Wyodak Plant under a separate long-term agreement. This coal supply agreement is collateralized by a mortgage on and a security interest in some of WRDC's coal reserves.

- Black Hills Power also owns a 35 percent interest in, and is the operator of, the Converter Station Site and South Rapid City Interconnection (the transmission tie), an AC-DC-AC transmission tie. Basin Electric owns the remaining ownership percentage. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides us with access to both the WECC region and the MAPP region. The total transfer capacity of the tie is 400 megawatts - 200 megawatts West to East and 200 megawatts from East to West. Black Hills Power is committed to pay its proportionate share of the additions and replacements to and operating and maintenance expenses of the transmission tie.

- Black Hills Power owns 52 percent of the Wygen III coal-fired generation facility. MDU and the City of Gillette each owns an undivided ownership interest in Wygen III and are obligated to make payments for costs associated with administrative services and their proportionate share of the costs of operating the plant for the life of the facility. We retain responsibility for plant operations. Our Coal Mining subsidiary supplies coal to Wygen III for the life of the plant.

- Colorado Electric owns 50 percent of the Busch Ranch Wind Project while AltaGas owns the remaining undivided ownership interest and is obligated to make payments for costs associated with their proportionate share of the costs of operating the wind project for the life of the facility. We retain responsibility for operations of the wind farm.

Non-Regulated Plants

Our consolidated financial statements include our share of a jointly-owned non-regulated power generation facility as described below. Our share of direct expenses for the jointly-owned facility is included in the corresponding categories of operating expenses in the accompanying Consolidated Statements of Income. Each of the respective owners is responsible for providing its own financing.

- Black Hills Wyoming owns 76.5 percent of the Wygen I plant while MEAN owns the remaining ownership percentage. MEAN is obligated to make payments for its share of the costs associated with administrative services, plant operations and coal supply provided by our Coal Mining subsidiary during the life of the facility. We retain responsibility for plant operations.

At Dec. 31, 2013, our interests in jointly-owned generating facilities and transmission systems were (in thousands):

Plant in Service

		Construction Work in Progress	Accumulated Depreciation
Wyodak Plant	$109,800	$192	$50,595
Transmission Tie	$19,648	$—	$4,741
Wygen I	$106,489	$1,412	$28,432
Wygen III	$131,468	$713	$10,593
Busch Ranch Wind Project	$18,590	$—	$841

(4) BUSINESS SEGMENTS INFORMATION

Our reportable segments are based on our method of internal reporting, which generally segregates the strategic business groups due to differences in products, services and regulation. All of our operations and assets are located within the United States.

On Feb. 29, 2012, we sold our Energy Marketing segment, Enserco, which resulted in this segment being reclassified as discontinued operations. For comparative purposes, all prior periods presented have been restated to reflect the reclassification of this segment as discontinued operations. Indirect corporate costs and inter-segment interest expense related to Enserco that have not been classified as discontinued operations have been reclassified to our Corporate segment. For further information see Note 21.

Segment information was as follows (in thousands):

Total Assets (net of inter-company eliminations) as of Dec. 31,	2013	2012
Utilities:		
Electric [(a)]	$2,525,947	$2,387,458
Gas	805,617	765,165
Non-regulated Energy:		
Power Generation [(a)]	95,692	119,170
Coal Mining	78,825	83,810
Oil and Gas	288,366	258,460
Corporate	80,731	115,408
Total assets	$3,875,178	$3,729,471

(a) The PPA under which Black Hills Colorado IPP provides generation to support Colorado Electric customers from the Pueblo Airport Generation station is accounted for as a capital lease. As such, assets owned by our Power Generation segment are recorded at Colorado Electric under accounting for a capital lease.

Capital Expenditures and Asset Acquisitions[(a)] for the years ended Dec. 31,	2013	2012
Utilities:		
Electric Utilities	$222,262	$167,263
Gas Utilities	63,205	45,711
Non-regulated Energy:		
Power Generation	13,533	5,547
Coal Mining	5,528	13,420
Oil and Gas	64,687	107,839
Corporate	10,319	7,376
Total capital expenditures and asset acquisitions of continuing operations	379,534	347,156
Total capital expenditures of discontinued operations	—	824
Total capital expenditures and asset acquisitions	$379,534	$347,980

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

Property, Plant and Equipment as of Dec. 31,	2013	2012
Utilities:		
Electric Utilities [(a)]	$2,464,603	$2,276,905
Gas Utilities	627,573	568,243
Non-regulated Energy:		
Power Generation [(a)]	153,517	140,719
Coal Mining	150,223	155,068
Oil and Gas	852,384	785,594
Corporate	11,145	4,243
Total property, plant and equipment	$4,259,445	$3,930,772

(a) The PPA under which Black Hills Colorado IPP provides generation to support Colorado Electric customers from the Pueblo Airport Generation station is accounted for as a capital lease. As such, assets owned by our Power Generation segment are recorded for at Colorado Electric under accounting for a capital lease.

Year ended Dec. 31, 2013	Consolidating Income Statement Electric Utilities	Gas Utilities	Power Generation	Coal Mining	Oil and Gas	Corporate	Inter-company Eliminations	Total
Revenue	$651,445	$539,689	$4,648	$25,186	$54,884	$—	$—	$1,275,852
Inter-company revenue	13,863	—	78,389	31,442	—	220,620	(344,314)	—
Total revenue	665,308	539,689	83,037	56,628	54,884	220,620	(344,314)	1,275,852
Fuel, purchased power and cost of natural gas sold	294,048	310,463	—	—	—	125	(112,489)	492,147
Operations and maintenance	159,961	126,073	30,186	39,519	40,365	202,809	(211,977)	386,936
Gain on sale of operating assets	—	—	—	—	—	—	—	—
Depreciation, depletion and amortization	77,704	26,381	5,091	11,523	21,770	11,624	(12,876)	141,217
Operating income (loss)	133,595	76,772	47,760	5,586	(7,251)	6,062	(6,972)	255,552
Interest expense [(a)]	(61,537)	(25,234)	(21,178)	(641)	(2,253)	(85,195)	84,250	(111,788)
Unrealized gain (loss) on interest rate swaps, net	—	—	—	—	—	30,169	—	30,169
Interest income	5,277	976	785	10	1,639	69,760	(76,724)	1,723
Other income (expense), net	633	(60)	1	2,304	108	41,453	(42,641)	1,798
Income tax benefit (expense)	(25,834)	(19,747)	(11,080)	(932)	3,545	(7,778)	218	(61,608)
Income (loss) from continuing operations	$52,134	$32,707	$16,288	$6,327	$(4,212)	$54,471	$(41,869)	$115,846

(a) Power Generation includes costs associated with interest rate swaps settled and write-off of deferred financing costs upon repayment of Black Hills Wyoming Project Financing and Corporate includes a the write-off of deferred financing costs and a make-whole provision from early repayment of long-term debt (see Note 5).

Consolidating Income Statement

Year ended Dec. 31, 2012	Electric Utilities	Gas Utilities	Power Generation	Coal Mining	Oil and Gas	Corporate	Inter-company Eliminations	Total
Revenue	$610,732	$454,081	$4,189	$25,810	$79,072	$—	$—	$1,173,884
Inter-company revenue	16,234	—	75,200	31,968	—	196,453	(319,855)	—
Total revenue	626,966	454,081	79,389	57,778	79,072	196,453	(319,855)	1,173,884
Fuel, purchased power and cost of natural gas sold	273,474	245,349	—	—	—	—	(111,757)	407,066
Operations and maintenance	146,527	117,390	29,991	42,553	43,267	179,059	(188,051)	370,736
Gain on sale of operating assets [(a)]	—	—	—	—	(29,129)	—	—	(29,129)
Depreciation, depletion and amortization	75,244	25,163	4,599	13,060	38,494	10,936	(12,864)	154,632
Impairment of long-lived assets[(b)]	—	—	—	—	26,868	—	—	26,868
Operating income (loss)	131,721	66,179	44,799	2,165	(428)	6,458	(7,183)	243,711
Interest expense [(c)]	(59,194)	(26,746)	(15,452)	(238)	(4,539)	(92,650)	85,209	(113,610)
Unrealized gain (loss) on interest rate swaps, net	—	—	—	—	—	1,882	—	1,882
Interest income	8,153	2,765	695	1,168	604	64,695	(76,123)	1,957
Other income (expense), net	1,182	105	7	2,616	207	48,769	(49,921)	2,965
Income tax benefit (expense)	(30,264)	(14,313)	(8,721)	(85)	1,927	3,187	(131)	(48,400)
Income (loss) from continuing operations	$51,598	$27,990	$21,328	$5,626	$(2,229)	$32,341	$(48,149)	$88,505

(a) Oil and Gas includes gain on sale of the Williston Basin assets (see Note 21).
(b) Oil and Gas includes a ceiling test impairment (see Note 12).
(c) Corporate includes a make-whole provision from early repayment of long-term debt (see Note 5).

Year ended Dec. 31, 2011	Consolidating Income Statement Electric Utilities	Gas Utilities	Power Generation	Coal Mining	Oil and Gas	Corporate	Inter-company Eliminations	Total
Revenue	$600,935	$554,584	$4,059	$32,802	$79,808	$—	$—	$1,272,188
Inter-company revenue	13,396	—	27,613	34,090	—	192,250	(267,349)	—
Total revenue	614,331	554,584	31,672	66,892	79,808	192,250	(267,349)	1,272,188
Fuel, purchased power and cost of natural gas sold	310,352	331,961	—	—	—	97	(67,421)	574,989
Operations and maintenance	142,815	121,980	16,538	56,617	41,380	170,947	(174,908)	375,369
Gain on sale of operating assets [(a)]	(768)	—	—	—	—	1	767	—
Depreciation, depletion and amortization	52,475	24,307	4,199	18,670	35,690	11,205	(10,955)	135,591
Operating income (loss)	109,457	76,336	10,935	(8,395)	2,738	10,000	(14,832)	186,239
Interest expense	(53,770)	(31,621)	(8,903)	(9)	(5,896)	(93,314)	102,130	(91,383)
Unrealized gain (loss) on interest rate swaps, net	—	—	—	—	—	(42,010)	—	(42,010)
Interest income	14,794	5,645	1,529	3,897	2	64,299	(88,149)	2,017
Other income (expense), net	481	217	1,094	2,192	(216)	46,510	(46,552)	3,726
Income tax benefit (expense)	(23,271)	(16,408)	(1,644)	1,891	1,651	19,289	268	(18,224)
Income (loss) from continuing operations	$47,691	$34,169	$3,011	$(424)	$(1,721)	$4,774	$(47,135)	$40,365

(a) Electric Utilities includes gain on sale of assets to a related party which was eliminated in consolidation.

(5) LONG-TERM DEBT

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

	Due Date	Interest Rate at Dec. 31, 2013	Dec. 31, 2013	Dec. 31, 2012
Corporate				
Senior unsecured notes due 2023	Nov. 30, 2023	4.25%	$525,000	$—
Senior unsecured notes due 2014 [a]	May 15, 2014	9.00%	—	250,000
Senior unsecured notes due 2020	July 15, 2020	5.88%	200,000	200,000
Corporate term loan due 2013 [a]	Sept. 30, 2013	NA	—	100,000
Corporate term loan due 2015 [b]	June 19, 2015	1.31%	275,000	—
Total Corporate Debt			1,000,000	550,000
Electric Utilities				
First Mortgage Bonds due 2032	Aug. 15, 2032	7.23%	75,000	75,000
First Mortgage Bonds due 2039	Nov. 1, 2039	6.13%	180,000	180,000
Unamortized discount on First Mortgage Bonds due 2039			(107)	(111)
Pollution control revenue bonds due 2024	Oct. 1, 2024	5.35%	12,200	12,200
First Mortgage Bonds due 2037	Nov. 20, 2037	6.67%	110,000	110,000
Industrial development revenue bonds due 2021, variable rate [c]	Sept. 1, 2021	0.11%	7,000	7,000
Industrial development revenue bonds due 2027, variable rate [c]	March 1, 2027	0.11%	10,000	10,000
Series 94A Debt, variable rate [c]	June 1, 2024	0.75%	2,855	2,855
Total Electric Utilities			396,948	396,944
Power Generation				
Black Hills Wyoming project financing, variable rate [a]	Dec. 9, 2016	3.59%	—	95,906
Total long-term debt			1,396,948	1,042,850
Less current maturities			—	103,973
Long-term debt, net of current maturities			$1,396,948	$938,877

(a) This debt repaid. See Debt Transactions discussed below.
(b) Variable interest rates, based on LIBOR plus a spread.
(c) Variable interest rate.

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

2014	$—
2015	$275,000
2016	$—
2017	$—
2018	$—
Thereafter	$1,122,055

Our debt securities contain certain restrictive financial covenants, all of which the Company and its subsidiaries were in compliance with at Dec. 31, 2013.

Substantially all of the tangible utility property of Black Hills Power and Cheyenne Light is subject to the lien of indentures securing their first mortgage bonds. First mortgage bonds of Black Hills Power and Cheyenne Light may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures. The first mortgage bonds issued by Black Hills Power and Cheyenne Light are either currently not callable or are subject to make-whole provisions which would eliminate any economic benefit for us to call the bonds.

Debt Transactions

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

- Redeem our $250 million senior unsecured 9.0 percent notes originally due on May 15, 2014. This repayment occurred on Dec. 19, 2013, for approximately $261 million which included a make-whole provision of approximately $8.5 million and accrued interest which are included in Interest expense on the accompanying Consolidated Statements of Income;
- Repay our variable interest rate Black Hills Wyoming project financing with a remaining balance of approximately $87 million originally due on Dec. 9, 2016, as well as the interest rate swaps designated to this project financing of $8.5 million which is included in Interest expense on the accompanying Consolidated Statements of Income;
- Settle the $250 million notional de-designated interest rate swaps for approximately $64 million;
- Pay down approximately $55 million of the Revolving Credit Facility;
- Remainder was used for general corporate purposes.

On June 21, 2013, we entered into a new long-term Corporate Term Loan for $275 million expiring on June 19, 2015. The proceeds from this new term loan was used to repay the $150 million term loan due on June 24, 2013, the $100 million corporate term loan due on Sept. 30, 2013, and approximately $25 million in short-term borrowing under our Revolving Credit Facility. The covenants of the new term loan are substantially the same as the Revolving Credit Facility. At Dec. 31, 2013, the cost of borrowing under this new term loan was 1.3125 percent (LIBOR plus a margin of 1.125 percent).

On Oct. 31, 2012, we redeemed $225 million of senior unsecured 6.5 percent notes, which were originally scheduled to mature on May 15, 2013, for approximately $239 million. The payment included accrued interest and a make-whole provision of $7.1 million which are included in Interest expense on the accompanying Consolidated Statements of Income.

Amortization Expense

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

	Deferred Financing Costs Remaining in Other Assets, Non-current on Balance Sheets at	Amortization Expense for the years ended Dec. 31,		
	Dec. 31, 2013	2013	2012	2011
Senior unsecured notes due 2023	$6,846	$86	$—	$—
Senior unsecured notes due 2014	$—	$635	$462	$462
Senior unsecured notes due 2020	$1,093	$167	$167	$167
First mortgage bonds due 2032	$618	$33	$33	$33
First mortgage bonds due 2039	$1,961	$76	$76	$76
First mortgage bonds due 2037	$736	$31	$31	$31

Black Hills Wyoming project financing due 2016 [(a)]	$—	$3,177	$1,037	$1,012
Other	$664	$57	$57	$70

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(a) This project financing was repaid in 2013 and the deferred financing costs were written-off.

Dividend Restrictions

Our credit facility and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. As of Dec. 31, 2013, we were in compliance with these covenants.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our shareholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. The following restrictions on distributions from our subsidiaries existed at Dec. 31, 2013:

- Our utilities are generally limited to the amount of dividends allowed to be paid to our utility holding company under the Federal Power Act and settlement agreements with state regulatory jurisdictions. As of Dec. 31, 2013, the restricted net assets at our Utilities Group were approximately $88 million.

(6) NOTES PAYABLE

Our Revolving Credit Facility and debt securities contain certain restrictive financial covenants. As of Dec. 31, 2013, we were in compliance with all of these covenants.

We had the following short-term debt outstanding at the Consolidated Balance Sheets date (in thousands):

	Balance Outstanding at	
	Dec. 31, 2013	Dec. 31, 2012
Revolving Credit Facility	$82,500	$127,000
Corporate Term Loan due June 2013	—	150,000
Total	$82,500	$277,000

Revolving Credit Facility

On Feb. 1, 2012, we entered into a new $500 million Revolving Credit Facility expiring Feb. 1, 2017. The facility contains an accordion feature allowing us, with the consent of the administrative agent, to increase the capacity of the facility to $750 million. The Revolving Credit Facility can be used for the issuance of letters of credit, to fund working capital needs and for other corporate purposes. Borrowings are available under a base rate option or a Eurodollar option. The cost of borrowings or letters of credit is determined based upon our credit ratings. At current credit ratings, the margins for base rate borrowings, Eurodollar borrowings and letters of credit were 0.375 percent, 1.375 percent and 1.375 percent, respectively, at Dec. 31, 2013. The facility contains a commitment fee that is charged on the unused amount of the Revolving Credit Facility. Based upon current credit ratings, the fee is 0.25 percent. As of Dec. 31, 2013 and 2012, we had outstanding letters of credit totaling approximately $22 million and approximately $36 million, respectively.

Deferred financing costs on the new facility of $2.8 million are being amortized over the estimated useful life of the Revolving Credit Facility and included in Interest expense on the accompanying Consolidated Statements of Income. Upon entering into the Revolving Credit Facility, $1.5 million of deferred financing costs relating to the previous credit facility were written off through Interest expense. The deferred financing costs on the new facility are being amortized as follows (in thousands):

	Deferred Financing Costs Remaining on Balance Sheets as of	Amortization Expense for the years ended Dec. 31,

	Dec. 31, 2013	2013	2012	2011
Revolving Credit Facility	$1,316	$752	$2,187	$1,891

Debt Covenants

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

	At Dec. 31, 2013	Covenant Requirement
Recourse leverage ratio	55 %	Less than 65 %

(7) ASSET RETIREMENT OBLIGATIONS

We have identified legal retirement obligations related to plugging and abandonment of natural gas and oil wells in the Oil and Gas segment, reclamation of coal mining sites at the Coal Mining segment and removal of fuel tanks, asbestos, transformers containing polychlorinated biphenyls, an evaporation pond and wind turbines at the regulated Electric Utilities segment and asbestos at our regulated utilities segments. We periodically review and update estimated costs related to these asset retirement obligations. The actual cost may vary from estimates because of regulatory requirements, changes in technology, and increased costs of labor, materials and equipment.

The following tables present the details of ARO which are included on the accompanying Consolidated Balance Sheets in Other deferred credits and other liabilities (in thousands):

	Dec. 31, 2012	Liabilities Incurred	Liabilities Settled	Accretion	Revisions to Prior Estimates [a]	Dec. 31, 2013
Electric Utilities	$6,981	$—	$—	$168	$(227)	$6,922
Gas Utilities	259	—	—	15	—	274
Coal Mining	20,286	3	(714)	1,052	—	20,627
Oil and Gas	23,022	143	(1,903)	1,450	1,316	24,028
Total	$50,548	$146	$(2,617)	$2,685	$1,089	$51,851

	Dec. 31, 2011	Liabilities Incurred	Liabilities Settled	Accretion	Revisions to Prior Estimates [a]	Dec. 31, 2012
Electric Utilities	$3,064	$3,626	$—	$291	$—	$6,981
Gas Utilities	270	—	(22)	11	—	259
Coal Mining	17,158	1,627	—	921	580	20,286
Oil and Gas	22,422	158	(1,059)	1,345	156	23,022
Total	$42,914	$5,411	$(1,081)	$2,568	$736	$50,548

(a) The Revisions to Prior Estimates reflects the change in the estimated liability for final reclamation adjusted for inflation, discount rate and market risk premium.

We also have legally required AROs related to certain assets within our electric and gas utility transmission and distribution systems. These retirement obligations are pursuant to an easement or franchise agreement and are only required if we discontinue our utility service under such easement or franchise agreement. Accordingly, it is not possible to estimate a time period when these obligations could be settled and therefore, a value for the cost of these obligations cannot be measured at this time.

(8) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operations of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures. Valuation methodologies for our derivatives are detailed within Note 1.

Market Risk

Market risk is the potential loss that may occur as a result of an adverse change in market price or rate. We are exposed to the following market risks, including, but not limited to:

- Commodity price risk associated with our natural long position with crude oil and natural gas reserves and production and fuel procurement for certain of our gas-fired generation assets; and

- Interest rate risk associated with our variable rate debt and our other short-term and long-term debt instruments.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty.

For production and generation activities, we attempt to mitigate our credit exposure by conducting business primarily with high credit quality entities, setting tenor and credit limits commensurate with counterparty financial strength, obtaining master netting agreements, and mitigating credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit, and other security agreements.

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer’s current creditworthiness, as determined by review of their current credit information. We maintain a provision for estimated credit losses based upon historical experience and any specific customer collection issue that is identified.

As of Dec. 31, 2013, our credit exposure included a $0.5 million exposure to a non-investment grade energy marketing company. The remainder of our credit exposure was concentrated primarily among retail utility customers, investment grade companies, cooperative utilities and federal agencies. Our derivative and hedging activities included in the accompanying Consolidated Balance Sheets, Consolidated Statements of Income and Consolidated Statements of Comprehensive Income (Loss) are detailed below and within Note 9.

Oil and Gas Exploration and Production

We produce natural gas and crude oil through our exploration and production activities. Our natural long positions, or unhedged open positions, result in commodity price risk and variability to our cash flows.

To mitigate commodity price risk and preserve cash flows, we primarily use over-the-counter swaps, exchange traded futures and related options to hedge portions of our crude oil and natural gas production. We elect hedge accounting on these instruments. These transactions were designated at inception as cash flow hedges, documented under accounting standards for derivatives and hedging, and initially met prospective effectiveness testing. Effectiveness of our hedging position is evaluated at least quarterly.

The derivatives were marked to fair value and were recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets. The effective portion of the gain or loss on these derivatives for which we have elected cash flow hedge accounting is reported in AOCI in the accompanying Consolidated Balance Sheets and the ineffective portion, if any, is reported in Revenue on the accompanying Consolidated Statements of Income (Loss).

The contract or notional amounts, terms of our commodity derivatives, and the derivative balances for our Oil and Gas segment reflected on the Consolidated Balance Sheets were as follows (dollars in thousands) as of:

	Dec. 31, 2013		Dec. 31, 2012	
	Crude oil futures, swaps and options	Natural gas futures, swaps and options	Crude oil futures, swaps and options	Natural gas futures, swaps and options
Notional [(a)]	412,500	7,082,500	528,000	8,215,500
Maximum terms in years [(b)]	0.25	0.08	1	0.75
Derivative assets, current	$55	$—	$1,405	$1,831
Derivative assets, non-current	$—	$—	$297	$170
Derivative liabilities, current	$—	$—	$847	$507
Derivative liabilities, non-current	$—	$—	$—	$—

(a) Crude in Bbls, gas in MMBtu.
(b) Refers to the term of the derivative instrument. Assets and liabilities are classified as current/non-current based on the timing of the hedged transaction and the corresponding settlement of the derivative instrument.

Based on Dec. 31, 2013 market prices, a $1.0 million loss would be reclassified from AOCI during 2014. Estimated and actual realized gains or losses will change during future periods as market prices fluctuate.

Utilities

The operations of our utilities, including power purchase arrangements where our utilities must provide the generation fuel (tolling agreements), expose our utility customers to volatility in natural gas prices; therefore, as allowed or required, by state utility commissions, we have entered into commission-approved hedging programs utilizing natural gas futures, options and basis swaps to reduce our customers' underlying exposure to these fluctuations. These transactions are considered derivatives, and in accordance with accounting standards for derivatives and hedging, mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets, net of balance sheet offsetting as permitted by GAAP. Unrealized and realized gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in the accompanying Consolidated Balance Sheets in accordance with the state utility commission guidelines. Accordingly, the hedging activity is recognized in the Consolidated Statements of Income (Loss) or the Consolidated Statements of Comprehensive Income (Loss) when the related costs are recovered through our rates.

The contract or notional amounts and terms of the natural gas derivative commodity instruments held by our Gas Utilities were as follows, as of:

	Dec. 31, 2013		Dec. 31, 2012	
	Notional (MMBtus)	Maximum Term (months)	Notional (MMBtus)	Maximum Term (months)
Natural gas futures purchased	17,930,000	84	15,350,000	83
Natural gas options purchased	3,890,000	8	2,430,000	2
Natural gas basis swaps purchased	14,785,000	60	12,020,000	72

We had the following derivative balances related to the hedges in our Utilities reflected in our Consolidated Balance Sheets as of (in thousands):

	Dec. 31, 2013	Dec. 31, 2012
Derivative assets, current	$662	$—
Derivative assets, non-current	$—	$43

Derivative liabilities, current	$—	$—
Derivative liabilities, non-current	$—	$—
Net unrealized (gain) loss included in Regulatory assets or Regulatory liabilities	$7,567	$9,596

Financing Activities

We entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations. The contract or notional amounts, terms of our interest rate swaps and the interest rate swaps balances reflected on the Consolidated Balance Sheets were as follows (dollars in thousands) as of:

	Dec. 31, 2013	Dec. 31, 2012	
	Interest Rate Swaps (a)	Interest Rate Swaps (b)	De-designated Interest Rate Swaps (c)
Notional	$75,000	$150,000	$250,000
Weighted average fixed interest rate	4.97 %	5.04 %	5.67 %
Maximum terms in years	3.0	4.0	1.0
Derivative liabilities, current	$3,474	$7,039	$88,148
Derivative liabilities, non-current	$5,614	$16,941	$—

(a) These swaps are designated to borrowings on our Revolving Credit Facility. These swaps are priced using three-month LIBOR, matching the floating portion of the related swaps.

(b) At Dec. 31, 2012, $75 million of these interest rate swaps were designated to borrowings on our Revolving Credit Facility and $75 million were designated to borrowings on our project financing debt at Black Hills Wyoming. These swaps are priced using three-month LIBOR, matching the floating portion of the related swaps. The portion of the swaps that were designated to Black Hills Wyoming were settled upon repayment of the Black Hills Wyoming project financing. See Note 5.

(c) Maximum terms in years reflect the amended early termination dates. If the early termination dates were not extended, the swaps would have required cash settlement based on the swap value at the termination date. These swaps were settled during the fourth quarter of 2013.

Based on Dec. 31, 2013 market interest rates and balances related to our designated interest rate swaps, a loss of approximately $3.5 million would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. Estimated and realized gains or losses will change during future periods as market interest rates change.

(9) FAIR VALUE MEASUREMENTS

Recurring Fair Value Measurements

There have been no significant transfers between Level 1 and Level 2 derivative balances during 2013 or 2012. Amounts included in cash collateral and counterparty netting in the following tables represent the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions, netting of asset and liability positions permitted in accordance with accounting standards for offsetting as well as cash collateral posted with the same counterparties.

A discussion of fair value of financial instruments is included in Note 10. The following tables set forth, by level within the fair value hierarchy, our gross assets and gross liabilities and related offsetting as permitted by GAAP that were accounted for at fair value on a recurring basis for derivative instruments (in thousands):

	As of Dec. 31, 2013				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
Assets:					
Commodity derivatives - Oil and Gas:					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	130	—	(75)	55
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	815	—	(815)	—
Commodity derivatives - Utilities	—	3,030	—	(2,368)	662
Total	$—	$3,975	$—	$(3,258)	$717
Liabilities:					
Commodity derivatives - Oil and Gas:					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	1,229	—	(1,229)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	531	—	(531)	—
Commodity derivatives - Utilities	—	9,100	—	(9,100)	—
Interest rate swaps	—	9,088	—	—	9,088
Total	$—	$19,948	$—	$(10,860)	$9,088

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	As of Dec. 31, 2012				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
Assets:					
Commodity derivatives - Oil and Gas:					
Options -- Oil	$—	$378	$—	$—	$378
Basis Swaps -- Oil	—	1,325	—	—	1,325
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	2,000	—	—	2,000
Commodity derivatives - Utilities	—	—	43	—	43
Total	$—	$3,703	$43	$—	$3,746
Liabilities:					
Commodity derivatives - Oil and Gas:					
Options -- Oil	$—	$1,131	$—	$(336)	$795
Basis Swaps -- Oil	—	502	—	(450)	52
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	1,127	—	(620)	507
Commodity derivatives - Utilities	—	8,576	—	(8,576)	—
Interest rate swaps	—	118,088	—	(5,960)	112,128
Total	$—	$129,424	$—	$(15,942)	$113,482

The following table presents the quantitative information about Level 3 fair value measurements (dollars in thousands):

	Fair Value at Dec. 31, 2012	Valuation Technique	Unobservable Input	Range (Weighted) Average
Assets:				
Commodity derivatives - Utilities (a)	$43	Independent price quotes	Long-term natural gas prices - Basis Differential	$(0.13)

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(a) The significant unobservable inputs used in the fair value measurement of the long-term OTC contracts are based on the average of price quotes from an independent third party market participant and the OTC contract broker. The unobservable inputs are long-term natural gas prices. Significant changes to these inputs along with the contract term would impact the derivative asset/liability and regulatory asset/liability, but will not impact the results of operations until the contract is settled under the original terms of the contract. The contracts will be classified as Level 2 once settlement is within 60 months of maturity and quoted market prices from a market exchange are available.

The following tables present the changes in Level 3 recurring fair value (in thousands):

Assets:	As of Dec. 31, 2013 Commodity Derivatives -- Utilities	As of Dec. 31, 2012 Commodity Derivatives -- Utilities
Balances as of beginning of period	$43	$—
Total gain (loss) included in AOCI/ Regulatory Asset	—	(54)
Purchases	—	192
Transfers out of Level 3[(a)]	(43)	(95)
Balances at end of period	$—	$43
Changes in unrealized gains (losses) relating to instruments still held as of period-end	$—	$(54)

(a) Transfers out of Level 3 would occur when the significant inputs become more observable such as the time between the valuation date and the delivery date of a transaction becomes shorter, positively impacting the availability of observable pricing inputs.

Fair Value Measures by Balance Sheet Classification

As required by accounting standards for derivatives and hedges, fair values within the following tables are presented on a gross basis reflecting the netting of asset and liability positions permitted in accordance with accounting standards for offsetting and under terms of our master netting agreements and the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions. However, the amounts do not include net cash collateral on deposit in margin accounts at Dec. 31, 2013 and 2012, to collateralize certain financial instruments, which are included in Derivative assets and/or Derivative liabilities. Therefore, the balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not agree with the amounts presented on our Consolidated Balance Sheets, nor will they correspond to the fair value measurements presented in Note 8.

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

		2013		2012	
	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:					
Commodity derivatives	Derivative assets - current	$248	$—	$2,874	$—
Commodity derivatives	Derivative assets - non-current	698	—	510	—
Commodity derivatives	Derivative liabilities - current	—	1,541	—	1,993
Commodity derivatives	Derivative liabilities - non-current	—	219	—	821
Interest rate swaps	Derivative liabilities - current	—	3,474	—	7,038
Interest rate swaps	Derivative liabilities - non-current	—	5,614	—	16,941
Total derivatives designated as hedges		$946	$10,848	$3,384	$26,793

Derivatives not designated as hedges:

Commodity derivatives	Derivative assets - current	$662	$—	$362	$—
Commodity derivatives	Derivative assets - non-current	—	—	—	—
Commodity derivatives	Derivative liabilities - current	—	—	1,180	4,957
Commodity derivatives	Derivative liabilities - non-current	—	6,732	406	5,153
Interest rate swaps	Derivative liabilities - current	—	—	—	94,108
Interest rate swaps	Derivative liabilities - non-current	—	—	—	—
Total derivatives not designated as hedges		$662	$6,732	$1,948	$104,218

Derivatives Offsetting

It is our policy to offset in our Consolidated Balance Sheets contracts which provide for legally enforceable netting for our accounts receivable and payable and derivative activities.

As required by accounting standards for derivatives and hedges, fair values within the following tables reconcile the gross amounts to the net amounts. Amounts included in Gross Amounts Offset on Consolidated Balance Sheets in the following tables include the netting of asset and liability positions permitted in accordance with accounting standards for offsetting as well as the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions as well as cash collateral posted with the same counterparties. Additionally, the amounts reflect cash collateral on deposit in margin accounts at Dec. 31, 2013 and Dec. 31, 2012, to collateralize certain financial instruments, which are included in Derivative assets and/or Derivative liabilities. Therefore, the gross amounts are not indicative of either our actual credit exposure or net economic exposure.

Offsetting of derivative assets and derivative liabilities on our Consolidated Balance Sheets at Dec. 31, 2013 was as follows (in thousands):

Derivative Assets	Gross Amounts of Derivative Assets	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Assets on Consolidated Balance Sheets
Subject to master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	$75	$(75)	$—
Oil and Gas - Crude Options	—	—	—
Oil and Gas - Natural Gas Basis Swaps	815	(815)	—
Utilities	3,030	(2,368)	662
Total derivative assets subject to a master netting agreement or similar arrangement	3,920	(3,258)	662
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	55	—	55
Oil and Gas - Crude Options	—	—	—
Oil and Gas - Natural Gas Basis Swaps	—	—	—
Utilities	—	—	—
Total derivative assets not subject to a master netting agreement or similar arrangement	55	—	55
Total derivative assets	$3,975	$(3,258)	$717

Derivative Liabilities	Gross Amounts of Derivative Liabilities	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Liabilities on Consolidated Balance Sheets
Subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	$1,229	$(1,229)	$—
Oil and Gas - Crude Options	—	—	—
Oil and Gas - Natural Gas Basis Swaps	531	(531)	—
Utilities	9,100	(9,100)	—
Interest Rate Swaps	—	—	—
Total derivative liabilities subject to a master netting agreement or similar arrangement	10,860	(10,860)	—
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	—	—	—
Oil and Gas - Crude Options	—	—	—
Oil and Gas - Natural Gas Basis Swaps	—	—	—
Utilities	—	—	—
Interest Rate Swaps	9,088	—	9,088
Total derivative liabilities not subject to a master netting agreement or similar arrangement	9,088	—	9,088
Total derivative liabilities	$19,948	$(10,860)	$9,088

Offsetting of derivative assets and derivative liabilities on our Consolidated Balance Sheets as of Dec. 31, 2012 were as follows (in thousands):

Derivative Assets	Gross Amounts of Derivative Assets	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Assets on Consolidated Balance Sheets
Subject to master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	$76	$—	$76
Oil and Gas - Crude Options	93	—	93
Oil and Gas - Natural Gas Basis Swaps	172	—	172
Utilities	1,629	(1,586)	43
Total derivative assets subject to a master netting agreement or similar arrangement	1,970	(1,586)	384
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	1,249	—	1,249
Oil and Gas - Crude Options	285	—	285
Oil and Gas - Natural Gas Basis Swaps	1,828	—	1,828
Utilities	—	—	—
Total derivative assets not subject to a master netting agreement or similar arrangement	3,362	—	3,362

Total derivative assets	$5,332	$(1,586	)$3,746

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Derivative Liabilities	Gross Amounts of Derivative Liabilities	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Liabilities on Consolidated Balance Sheets
Subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	$449	$(449)	$—
Oil and Gas - Crude Options	337	(337)	—
Oil and Gas - Natural Gas Basis Swaps	620	(620)	—
Utilities	8,576	(8,576)	—
Interest Rate Swaps	—	—	—
Total derivative liabilities subject to a master netting agreement or similar arrangement	9,982	(9,982)	—
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Oil and Gas - Crude Basis Swaps	52	—	52
Oil and Gas - Crude Options	795	—	795
Oil and Gas - Natural Gas Basis Swaps	507	—	507
Utilities	—	—	—
Interest Rate Swaps	118,088	(5,960)	112,128
Total derivative liabilities not subject to a master netting agreement or similar arrangement	119,442	(5,960)	113,482
Total derivative liabilities	$129,424	$(15,942)	$113,482

Derivative assets and derivative liabilities and collateral held by counterparty included in our Consolidated Balance Sheets as of Dec. 31, 2013 were (in thousands):

Contract Type		Net Amount of Total Derivative Assets	Gross Amounts Not Offset on Consolidated Balance Sheets Cash Collateral Received	Net Amount with Counterparty
Assets:				
Oil and Gas	Counterparty A	$—	$—	$—
Oil and Gas	Counterparty B	55	—	55
Utilities	Counterparty A	662	—	662
		$717	$—	$717

Contract Type		Net Amount of Total Derivative Liabilities	Gross Amounts Not Offset on Consolidated Balance Sheets Cash Collateral Paid	Net Amount with Counterparty
Liabilities:				
Oil and Gas	Counterparty A	$—	$(1,631)	$(1,631)
Oil and Gas	Counterparty B	—	—	—
Utilities	Counterparty A	—	(3,390)	(3,390)
Interest Rate Swaps	Counterparty F	9,088	—	9,088

$9,088	$(5,021	)$4,067

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Derivative assets and derivative liabilities and collateral held by counterparty included in our Consolidated Balance Sheets as of Dec. 31, 2012 were (in thousands):

Contract Type		Net Amount of Total Derivative Assets	Gross Amounts Not Offset on Consolidated Balance Sheets Cash Collateral Received	Net Amount with Counterparty
Assets:				
Oil and Gas	Counterparty A	$341	$—	$341
Oil and Gas	Counterparty B	3,362	—	3,362
Utilities	Counterparty A	43	—	43
		$3,746	$—	$3,746

Contract Type		Net Amount of Total Derivative Liabilities	Gross Amounts Not Offset on Consolidated Balance Sheets Cash Collateral Paid	Net Amount with Counterparty
Liabilities:				
Oil and Gas	Counterparty A	$—	$(1,787)	$(1,787)
Oil and Gas	Counterparty B	1,354	—	1,354
Utilities	Counterparty A	—	(4,354)	(4,354)
Interest Rate Swap	Counterparty D	4,588	—	4,588
Interest Rate Swap	Counterparty E	29,245	—	29,245
Interest Rate Swap	Counterparty F	12,721	—	12,721
Interest Rate Swap	Counterparty G	26,520	—	26,520
Interest Rate Swap	Counterparty H	16,809	—	16,809
Interest Rate Swap	Counterparty I	22,245	—	22,245
		$113,482	$(6,141)	$107,341

A description of our derivative activities is included in Note 8. The following tables present the impact that derivatives had on our Consolidated Statements of Income (Loss).

Cash Flow Hedges

The impact of cash flow hedges on our Consolidated Statements of Income (Loss) for years ended were as follows (in thousands):

	Dec. 31, 2013				
Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	$7,935	Interest expense	$6,989		$—
Commodity derivatives	(956)	Revenue	(927)		—
Total	$6,979		$6,062		$—

Derivatives in Cash Flow Hedging Relationships	Dec. 31, 2012 Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	$(4,794)	Interest expense	$(7,607)		$—
Commodity derivatives	2,639	Revenue	8,784		—
Total	$(2,155)		$1,177		$—

Derivatives in Cash Flow Hedging Relationships	Dec. 31, 2011 Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	$(12,280)	Interest expense	$(7,664)		$—
Commodity derivatives	7,741	Revenue	5,487		—
Total	$(4,539)		$(2,177)		$—

Derivatives Not Designated as Hedge Instruments

The impact of derivative instruments not designated as hedge instruments on our Consolidated Statements of Income (Loss) for the years ended Dec. 31 were as follows (in thousands):

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	2013 Amount of Gain/(Loss) on Derivatives Recognized in Income	2012 Amount of Gain/(Loss) on Derivatives Recognized in Income	2011 Amount of Gain/(Loss) on Derivatives Recognized in Income
Interest rate swaps - unrealized	Unrealized gain (loss) on interest rate swap, net	$30,169	$1,882	$(42,010)
Interest rate swaps - realized	Interest expense	(12,902)	(12,959)	(13,373)
		$17,267	$(11,077)	$(55,383)

(10) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 9, were as follows at Dec. 31 (in thousands):

	2013		2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [(a)]	$7,841	$7,841	$15,462	$15,462
Restricted cash and equivalents [(a)]	$2	$2	$7,916	$7,916
Notes payable [(a)]	$82,500	$82,500	$277,000	$277,000
Long-term debt, including current maturities [(b)]	$1,396,948	$1,491,422	$1,042,850	$1,231,559

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(a) Carrying value approximates fair value due to either short-term length of maturity or variable interest rates that approximate prevailing market rates and therefore is classified in Level 1 in the fair value hierarchy.

(b) Long-term debt is valued based on observable inputs available either directly or indirectly for similar liabilities in active markets and therefore is classified in Level 2 in the fair value hierarchy.

Cash and Cash Equivalents

Included in cash and cash equivalents is cash, overnight repurchase agreement accounts, money market funds and term deposits. As part of our cash management process, excess operating cash is invested in overnight repurchase agreements with our bank. Repurchase agreements are not deposits and are not insured by the U.S. Government, the FDIC or any other government agency and involve investment risk including possible loss of principal. We believe however, that the market risk arising from holding these financial instruments is minimal.

Restricted Cash and Equivalents

Restricted cash and cash equivalents represent restricted cash and uninsured term deposits.

Notes Payable

2013 Notes Payable represents our Revolving Credit Facility while 2012 also includes certain corporate term loans.

Long-Term Debt

For additional information on our long-term debt, see Note 5.

(11) STOCK

Equity Compensation Plans

Our 2005 Omnibus Incentive Plan allows for the granting of stock, restricted stock, restricted stock units, stock options and performance shares. We had 768,953 shares available to grant at Dec. 31, 2013.

Compensation expense is determined using the grant date fair value estimated in accordance with the provisions of accounting standards for stock compensation and is recognized over the vesting periods of the individual awards. As of Dec. 31, 2013, total unrecognized compensation expense related to non-vested stock awards was approximately $9.9 million and is expected to be recognized over a weighted-average period of 1.7 years. Stock-based compensation expense included in Operations and maintenance on the accompanying Consolidated Statements of Income was as follows for the years ended Dec. 31 (in thousands):

	2013	2012	2011
Stock-based compensation expense	$12,595	$8,271	$5,643

Stock Options

We have granted options with an option exercise price equal to the fair market value of the stock on the day of the grant. The options granted vest proportionately over 3 years and expire 10 years after the grant date.

A summary of the status of the stock options at Dec. 31, 2013 was as follows:

	Shares (in thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Balance at beginning of period	121	$ 31.23		
Granted [(a)]	10	40.39		
Forfeited/canceled	—	—		
Expired	(4)	29.09		
Exercised	(66)	30.87		
Balance at end of period	61	$ 33.25	7.3	$1,165
Exercisable at end of period	26	$ 31.69	6.5	$534

(a) The grant date fair value of the 2013 awards was $7.65 based on a Black-Scholes option pricing model. Assumptions used to estimate the fair value were a 1.4 percent risk free interest rate, 29.3 percent expected price volatility, 3.8 percent expected dividend yield and a 7 year expected life.

The table below provides details of our option plans at Dec. 31 (in thousands):

	2013	2012	2011
Summary of Stock Options			
Unrecognized compensation expense	$130	$218	$479
Intrinsic value of options exercised [(a)]	$789	$623	$94
Net cash received from exercise of options	$2,046	$2,839	$1,009
Tax benefit realized from exercise of shares [(b)]	$276	$218	$33

(a) The intrinsic value represents the amount by which the market price of the stock on the date of exercise exceeded the exercise price of the option.
(b) The tax benefit realized from the exercise of shares granted was recorded as an increase in equity.

As of Dec. 31, 2013, the unrecognized compensation expense related to non-vested stock options is expected to be recognized over a weighted-average period of 1.1 years.

Restricted Stock

The fair value of restricted stock awards equals the market price of our stock on the date of grant.

The shares carry a restriction on the ability to sell the shares until the shares vest. The shares substantially vest over 3 years, contingent on continued employment. Compensation expense related to the awards is recognized over the vesting period.

A summary of the status of the restricted stock at Dec. 31, 2013, was as follows:

	Restricted Stock	Weighted-Average Grant Date Fair Value
	(in thousands)	
Restricted Stock balance at beginning of period	287	$32.23
Granted	120	40.56
Vested	(138)	30.62
Forfeited	(7)	35.50
Restricted Stock at end of period	262	$36.76

The weighted-average grant-date fair value of restricted stock granted and the total fair value of shares vested during the years ended Dec. 31, was as follows:

	Weighted-Average Grant Date Fair Value	Total Fair Value of Shares Vested (in thousands)
2013	$40.56	$5,842
2012	$34.99	$3,781
2011	$30.33	$3,211

As of Dec. 31, 2013, there was $5.8 million of unrecognized compensation expense related to non-vested restricted stock that is expected to be recognized over a weighted-average period of 1.8 years.

Performance Share Plan

Certain officers of the Company and its subsidiaries are participants in a performance share award plan, a market-based plan. Performance shares are awarded based on our total shareholder return over designated performance periods as measured against a selected peer group. In addition, certain stock price performance must be achieved for a payout to occur. The final value of the performance shares will vary according to the number of shares of common stock that are ultimately granted based upon the actual level of attainment of the performance criteria.

The performance awards are paid 50 percent in cash and 50 percent in common stock. The cash portion accrued is classified as a liability and the stock portion is classified as equity. In the event of a change-in-control, performance awards are paid 100 percent in cash. If it is determined that a change-in-control is probable, the equity portion of $1.9 million at Dec. 31, 2013 would be reclassified as a liability.

Outstanding performance periods at Dec. 31 were as follows (shares in thousands):

			Possible Payout Range of Target	
Grant Date	Performance Period	Target Grant of Shares	Minimum	Maximum
Jan. 1, 2011	Jan. 1, 2011 - Dec. 31, 2013	62	0%	175%
Jan. 1, 2012	Jan. 1, 2012 - Dec. 31, 2014	64	0%	200%
Jan. 1, 2013	Jan. 1, 2013 - Dec. 31, 2015	61	0%	200%

A summary of the status of the Performance Share Plan at Dec. 31 was as follows:

	Equity Portion		Liability Portion	
	Shares (in thousands)	Weighted-Average Grant Date Fair Value	Shares (in thousands)	Weighted-Average Fair Value at Dec. 31, 2013
Performance Shares balance at beginning of period	96	$ 27.49	96	
Granted	31	35.85	31	
Forfeited	(1)	33.85	(1)	
Vested	(33)	24.26	(33)	
Performance Shares balance at end of period	93	$ 31.34	93	$95.79

The grant date fair values for the performance shares granted in 2013, 2012 and 2011 were determined by Monte Carlo simulation using a blended volatility of 20 percent, 21 percent and 30 percent, respectively, comprised of 50 percent historical volatility and 50 percent implied volatility and the average risk-free interest rate of the three-year United States Treasury security rate in effect as of the grant date.

The weighted-average grant-date fair value of performance share awards granted in the years ended was as follows:

	Weighted Average Grant Date Fair Value
Dec. 31, 2013	$35.85
Dec. 31, 2012	$32.26
Dec. 31, 2011	$25.92

Performance plan payouts have been as follows (dollars and shares in thousands):

Performance Period	Year of Payment	Stock Issued	Cash Paid	Total Intrinsic Value
Jan. 1, 2010 to Dec. 31, 2012	2013	63	$2,267	$4,533
Jan. 1, 2009 to Dec. 31, 2011	2012	—	$—	$—
Jan. 1, 2008 to Dec. 31, 2010	2011	—	$—	$—

On Jan. 29, 2014, the Compensation Committee of our Board of Directors determined that the Company's total shareholder return for the Jan. 1, 2011 through Dec. 31, 2013 performance period was at the 94th percentile of its peer group and confirmed a payout equal to 175 percent of target shares, valued at $6.0 million. The payout was fully accrued at Dec. 31, 2013.

As of Dec. 31, 2013, there was $3.9 million of unrecognized compensation expense related to outstanding performance share plans that is expected to be recognized over a weighted-average period of 1.6 years.

Shareholder Dividend Reinvestment and Stock Purchase Plan

We have a DRIP under which shareholders may purchase additional shares of common stock through dividend reinvestment and/or optional cash payments at 100 percent of the recent average market price. We have the option of issuing new shares or purchasing the shares on the open market. We are currently issuing new shares.

A summary of the Dividend Reinvestment and Stock Purchase Plan for the years ended and at Dec. 31 is as follows (shares in thousands):

	2013	2012
Shares Issued	67	101
Weighted Average Price	$46.78	$33.58
Unissued Shares Available	286	353

Equity Issuance

On Nov. 10, 2010, we entered into an Equity Forward Agreement with J.P. Morgan in connection with a public offering of 4,000,000 shares of Black Hills Corporation common stock. Subsequently, the underwriters exercised the over-allotment option to purchase 413,519 additional shares under the same terms as the original Forward Equity Agreement. On Nov. 1, 2011 we issued 4,413,519 shares of common stock in return for proceeds of approximately $120 million under an Equity Forward Agreement.

Preferred Stock

Our articles of incorporation authorize the issuance of 25 million shares of preferred stock of which we had no shares of preferred stock outstanding.

(12) IMPAIRMENT OF LONG-LIVED ASSETS

Under the full cost method of accounting used by our Oil and Gas segment to account for exploration, development, and acquisition of crude oil and natural gas reserves, all costs attributable to these activities are capitalized. These capitalized costs, less accumulated amortization and related deferred income taxes, are subject to a ceiling test that limits the pooled costs to the aggregate of the discounted value of future net revenue attributable to proved natural gas and crude oil reserves using a discount rate defined by the SEC plus the lower of cost or market value of unevaluated properties. Any costs in excess of the ceiling are written off as a non-cash charge.

As a result of continued low commodity prices in the second quarter of 2012, we recorded a $27 million non-cash impairment of oil and gas assets included in the Oil and Gas segment. In determining the ceiling value of our assets, we utilized the average of the quoted prices from the first day of each month from the previous 12 months. For natural gas, the average NYMEX price was $3.15 per Mcf, adjusted to $2.66 per Mcf at the wellhead; for crude oil, the average NYMEX price was $95.67 per barrel, adjusted to $85.36 per barrel at the wellhead.

(13) OPERATING LEASES

We have entered into lease agreements for vehicles, equipment and office facilities. Rental expense incurred under these operating leases, including month to month leases, for the years ended Dec. 31 was as follows (in thousands):

	2013	2012	2011
Rent expense	$7,169	$6,839	$6,125

The following is a schedule of future minimum payments required under the operating lease agreements (in thousands):

2014	$2,782
2015	$2,583
2016	$1,938
2017	$1,747
2018	$1,697
Thereafter	$5,452

(14) INCOME TAXES

Income tax expense (benefit) from continuing operations for the years ended Dec. 31 was (in thousands):

	2013	2012	2011
Current:			
Current federal income tax expense (benefit)	$(2,003)	$4,972	$(14,539)
Current state income tax expense (benefit)	(173)	3,712	(837)
	(2,176)	8,684	(15,376)
Deferred:			
Deferred federal income tax expense (benefit)	56,963	39,876	30,876
Deferred state income tax expense (benefit)	7,033	68	2,970
Tax credit amortization expense (benefit)	(212)	(228)	(246)
	63,784	39,716	33,600
Total income tax expense (benefit)	$61,608	$48,400	$18,224

The temporary differences, which gave rise to the net deferred tax liability, for the years ended Dec. 31 were as follows (in thousands):

	2013	2012
Deferred tax assets:		
Regulatory liabilities	$33,172	$57,471
Employee benefits	28,724	23,767
Items of other comprehensive income (loss)	9,733	20,038
Derivative fair value adjustments	1,594	35,947
Federal net operating loss	166,095	147,153
Asset impairment	55,124	55,971
State tax credits	14,948	15,546
Other deferred tax assets	32,803	36,502
Less: Valuation allowance	(1,806)	(6,192)
Total deferred tax assets	340,387	386,203
Deferred tax liabilities:		
Accelerated depreciation, amortization and other plant-related differences	(598,415)	(571,262)
Regulatory assets	(24,581)	(23,537)
Mining development and oil exploration	(69,799)	(48,411)
Deferred costs	(15,593)	(17,723)
State deferred tax liability	(30,293)	(19,986)
Other deferred tax liabilities	(15,104)	(13,961)
Total deferred tax liabilities	(753,785)	(694,880)
Net deferred tax liability	$(413,398)	$(308,677)

The effective tax rate differs from the federal statutory rate for the years ended Dec. 31, as follows:

	2013	2012	2011
Federal statutory rate	35.0 %	35.0 %	35.0 %
State income tax (net of federal tax effect)	2.4	2.0	1.8
Amortization of excess deferred and investment tax credits	(0.1)	(0.2)	(0.5)
Percentage depletion in excess of cost	(1.0)	(1.3)	(2.5)
Equity AFUDC	—	—	(0.5)
Tax credits	(0.5)	—	—
Accounting for uncertain tax positions adjustment	0.7	0.8	2.8
Flow-through adjustments [(a)]	(0.9)	(1.3)	(4.5)
Other tax differences	(0.9)	0.4	(0.5)
	34.7 %	35.4 %	31.1 %

(a) The flow-through adjustments relate primarily to an accounting method change for tax purposes that allows us to take a current tax deduction for repair costs that continue to be capitalized for book purposes. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and flowed the tax benefit through to our customers in the form of lower rates as a result of a rate case settlement that occurred during 2010. A regulatory asset was established to reflect the recovery of future increases in taxes payable from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record a tax benefit consistent with the flow-through method. Such tax benefit has remained somewhat constant, but its impact on the effective tax rate is predicated on the level of pre-tax net income as evidenced in 2011.

At Dec. 31, 2013, we had federal and state NOL carryforwards which will expire at various dates as follows (in thousands):

Net Operating Loss Carryforward	Amounts	Expiration Dates		
Federal	$482,989	2019	to	2033
State	$423,570	2013	to	2033

As of Dec. 31, 2013, we had a $0.5 million valuation allowance against the state NOL carryforwards. The re-evaluation of our ability to utilize such NOLs resulted in a decrease of the valuation allowance of approximately $1.7 million of which $0.7 million resulted in a decrease to tax expense. The valuation allowance adjustment was primarily attributable to NOLs whose carryforward period has expired resulting in an offset to the deferred tax asset. Ultimate usage of these NOLs depends upon our future tax filings. If the valuation allowance is adjusted due to higher or lower than anticipated utilization of the NOLs, the offsetting amount will affect tax expense.

The following table reconciles the total amounts of unrecognized tax benefits, without interest, at the beginning and end of the period included in Other deferred credits and other liabilities on the accompanying Consolidated Balance Sheets (in thousands):

	Changes in Uncertain Tax Positions
Beginning balance at Jan. 1, 2011	$50,135
Additions for prior year tax positions	2,725
Reductions for prior year tax positions	(3,533)
Ending balance at Dec. 31, 2011	49,327
Additions for prior year tax positions	111
Reductions for prior year tax positions	(8,906)
Additions for current year tax positions	151
Settlements	—
Ending balance at Dec. 31, 2012	40,683
Additions for prior year tax positions	1,526
Reductions for prior year tax positions	(4,578)
Additions for current year tax positions	—
Settlements	—
Ending balance at Dec. 31, 2013	$37,631

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $1.7 million.

We recognized interest expense of $1.6 million, $1.4 million and $1.4 million for the years ended Dec. 31, 2013, 2012 and 2011, respectively.

We had approximately $9.9 million pre-tax and $8.3 million pre-tax of accrued interest associated with income taxes at Dec. 31, 2013 and 2012, respectively.

We file income tax returns with the IRS and various state jurisdictions. We are currently under examination by the IRS for the 2007 to 2009 tax years and recently received notification to audit the 2010 to 2012 tax years. We remain subject to examination by Canadian income tax authorities for tax years as early as 1999.

We have deferred a substantial amount of tax payments through various tax planning strategies including the deferral of approximately $125 million in income taxes attributable to the like-kind exchange effectuated in connection with the IPP Transaction and Aquila Transaction that occurred in 2008. The IRS has challenged our position with respect to the like-kind exchange and it is reasonably possible that the total unrecognized tax benefits attributable to such transaction could change significantly due to a settlement with the IRS that is anticipated to occur on or before Dec. 31, 2014. However, based on the information currently available, it is difficult to determine any reasonable estimate of the financial statement impact including the impact on the effective tax rate.

Excess foreign tax credits have been generated and are available to offset United States federal income taxes. At Dec. 31, 2013, we had foreign tax credit carryforwards of approximately $0.5 million, which expire between 2015 and 2017.

As of Dec. 31, 2013, we had a $0.5 million valuation allowance against the foreign tax credit carryforwards. In addition, the carryforward balance reflects the expected utilization of approximately $1.8 million of foreign tax credits to be included as computational adjustments upon finalization of our current IRS examination covering tax years 2007 to 2009. Such foreign tax credits have been reflected as an offset to liabilities for unrecognized tax benefits in recognition of the estimated impact the resolution of material uncertain tax positions could have with respect to utilization.

State tax credits have been generated and are available to offset future state income taxes. At Dec. 31, 2013, we had the following state tax credit carryforwards (in thousands):

State Tax Credit Carryforwards		Expiration Years		
Investment tax credit	$14,793	2023	to	2025
Research and development	$155	No expiration		

As of Dec. 31, 2013, we had a $0.8 million valuation allowance against the state tax credit carryforwards. The re-evaluation of our ability to utilize such credits resulted in a decrease of the valuation allowance of approximately $2.6 million of which approximately $1.1 million resulted in a decrease to tax expense. The remaining $1.5 million decrease is attributable to our regulated business and is being accounted for under the deferral method whereby the credits are amortized to tax expense over the estimated useful life of the underlying asset that generated the credit. The valuation allowance adjustment was primarily attributable to an increase in forecasted apportionment factors. Ultimate usage of these credits depends upon our future tax filings. If the valuation allowance is adjusted due to higher or lower than anticipated utilization of the state tax credit carryforwards, the offsetting amount will affect tax expense.

(15) OTHER COMPREHENSIVE INCOME

The components of the reclassification adjustments for the period, net of tax, included in Other Comprehensive Income were as follows (in thousands):

	Location on the Consolidated Statements of Income	Amount Reclassified from AOCI Dec. 31, 2013	Dec. 31, 2012
Gains and losses on cash flow hedges:			
Interest rate swaps	Interest expense	$6,989	$7,607
Commodity contracts	Revenue	(927)	(8,784)
		6,062	(1,177)
Income tax	Income tax benefit (expense)	(2,016)	534
Total reclassification adjustments related to cash flow hedges, net of tax		$4,046	$(643)
Amortization of defined benefit plans:			
Prior service cost	Utilities - Operations and maintenance	$(125)	$—
	Non-regulated energy operations and maintenance	(128)	—
Actuarial gain (loss)	Utilities - Operations and maintenance	1,693	—
	Non-regulated energy operations and maintenance	1,098	—
		2,538	—
Income tax	Income tax benefit (expense)	(883)	—
Total reclassification adjustments related to defined benefit plans, net of tax		$1,655	$—

Balances by classification included within Accumulated other comprehensive income (loss) on the accompanying Consolidated Balance Sheets were as follows (in thousands):

	Derivatives Designated as Cash Flow Hedges			
	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
As of Dec. 31, 2012	$(16,313)	$600	$(19,775)	$(35,488)
Other comprehensive income (loss)	9,688	(1,108)	9,486	18,066
As of Dec. 31, 2013	$(6,625)	$(508)	$(10,289)	$(17,422)

	Derivatives Designated as Cash Flow Hedges			
	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
As of Dec. 31, 2011	$(18,140)	$4,338	$(19,076)	$(32,878)
Other comprehensive income (loss)	1,827	(3,738)	(699)	(2,610)
As of Dec. 31, 2012	$(16,313)	$600	$(19,775)	$(35,488)

(16) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Years ended Dec. 31,	2013	2012	2011
	(in thousands)		
Non-cash investing activities and financing from continuing operations -			
Property, plant and equipment acquired with accrued liabilities	$59,811	$35,556	$37,529
Increase (decrease) in capitalized assets associated with asset retirement obligations	$1,235	$5,743	$(1,525)
Cash (paid) refunded during the period for continuing operations-			
Interest (net of amount capitalized)	$(108,361)	$(116,593)	