BLACK HILLS CORP /SD/
Form 10-K
February 25, 2013

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, 2012

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, 2012 $1,400,316,896

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, 2013
Common stock, $1.00 par value	44,222,903 shares

Documents Incorporated by Reference
Portions of the Registrant's Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2013 Annual Meeting of Stockholders to be held on April 23, 2013, 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
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
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
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
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOE	United States Department of Energy
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 power 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
GCA	Gas Cost Adjustment -- adjustments that allow us to pass the prudently-incurred cost of gas and certain services through to the customer.
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
Hastings	Hastings Fund Management Ltd
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 Cogeneration Facility	Partnership investment owned 50 percent by Black Hills Electric Generation, sold Jan. 18, 2011
IFRS	International Financial Reporting Standards

IIF	IIF BH Investment LLC, a subsidiary of an investment entity advised by J.P. Morgan Asset Management
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 to affiliates of Hastings and IIF
IRS	United States Internal Revenue Service

IUB	Iowa Utilities Board
J.P. Morgan	J.P. Morgan Securities LLC
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 (Gallon equals 7 Mcfe)
NO_x	Nitrogen oxide
NOL	Net operating loss
NPDES	National Pollutant Discharge Elimination System
NPSC	Nebraska Public Service Commission
NYMEX	New York Mercantile Exchange
OPEC	Organization of the Petroleum Exporting Countries
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

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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
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.
ug/m^3	Micrograms per Cubic Meter of Air
Twin Eagle	Twin Eagle Resource Management, LLC
VEBA	Voluntary Employee Benefit Association
VOC	Volatile Organic Compounds
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 diversified 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 our regulated Electric Utilities and regulated Gas Utilities segments, and our Non-regulated Energy Group is comprised of our Power Generation, Coal Mining and Oil and Gas segments.

For more than 15 years, 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. For comparative purposes, all prior periods presented have been restated to reflect the reclassification of this segment as discontinued operations. See Note 23 in the accompanying Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for further details.

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 202,000 electric customers in South Dakota, Wyoming, Colorado and Montana and also distributes natural gas to approximately 35,000 gas utility customers of Cheyenne Light in Cheyenne, Wyo. Our Gas Utilities segment serves approximately 532,000 natural gas utility customers in Colorado, Nebraska, Iowa and Kansas. Our Electric Utilities own 859 megawatts of generation and 8,530 miles of electric transmission and distribution lines, and our Gas Utilities own 624 miles of intrastate gas transmission pipelines and 19,979 miles of gas distribution mains and service lines. Our Utilities Group generated net income of $79.6 million for the year ended December 31, 2012 and had total assets of $3.2 billion at December 31, 2012.

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. 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 $24.7 million for the year ended December 31, 2012 and had total assets of $0.5 billion at December 31, 2012.

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 17 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 202,000 customers; and also distribute natural gas to approximately 35,000 natural gas utility customers of Cheyenne Light in 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 532,000 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)					
	2012		2011		2010	
	Summer	Winter	Summer	Winter	Summer	Winter
Black Hills Power	449	362	452	408	396	377
Cheyenne Light	187	174	181	175	176	164
Colorado Electric	400	284	392	297	384	289
Total Electric Utilities Peak Demands	1,036	820	1,025	880	956	830

Regulated Power Plants

As of December 31, 2012, 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:					
Wygen III [1]	Coal	Gillette, Wyo.	52.0%	57.2	2010
Neil Simpson II	Coal	Gillette, Wyo.	100.0%	90.0	1995
Wyodak [2]	Coal	Gillette, Wyo.	20.0%	72.4	1978
Osage [3]	Coal	Osage, Wyo.	100.0%	34.5	1948-1952
Ben French [3]	Coal	Rapid City, S.D.	100.0%	25.0	1960
Neil Simpson I [3]	Coal	Gillette, Wyo.	100.0%	21.8	1969
Neil Simpson CT	Gas	Gillette, Wyo.	100.0%	40.0	2000
Lange CT	Gas	Rapid City, S.D.	100.0%	40.0	2002
Ben French Diesel #1-5	Oil	Rapid City, S.D.	100.0%	10.0	1965
Ben French CTs #1-4	Gas/Oil	Rapid City, S.D.	100.0%	80.0	1977-1979
Cheyenne Light:					
Wygen II	Coal	Gillette, Wyo.	100.0%	95.0	2008
Colorado Electric [4]:					
Busch Ranch Wind Farm [5]	Wind	Pueblo, Colo.	50.0%	14.5	2012
Pueblo Airport Generation	Gas	Pueblo, Colo.	100.0%	180.0	2011
W.N. Clark #1-2 [6]	Coal	Canon City, Colo.	100.0%	40.0	1955, 1959
Pueblo #5 [3]	Gas	Pueblo, Colo.	100.0%	9.0	1941, 2001
Pueblo #6 [3]	Gas	Pueblo, Colo.	100.0%	20.0	1949
AIP Diesel	Oil	Pueblo, Colo.	100.0%	10.0	2001
Diesel #1-5	Oil	Pueblo, Colo.	100.0%	10.0	1964
Diesel #1-5	Oil	Rocky Ford, Colo.	100.0%	10.0	1964
Total Megawatt Capacity				859.4	

(1) 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 furnishes all of the fuel supply for the plant.

(2) 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 furnishes all of the fuel supply for the plant.

(3) Operations at Osage were suspended Oct. 1, 2010, Ben French was suspended on Aug. 31, 2012 and Pueblo Unit #5 and Pueblo Unit #6 were suspended as of Dec. 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 insignificant at the time of retirement, we would reasonably expect any remaining value to be recovered through future rates.

(4) Colorado Electric entered into a 20-year PPA with Black Hills Colorado IPP for 200 megawatts of power from their gas-fired plants. This PPA, accounted for as a capital lease, was effective on Jan. 1, 2012.

(5) 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.

(6)

In December 2010, Colorado Electric received a final order from the CPUC that approved the retirement of its W.N. Clark coal-fired generation facility by Dec. 31, 2013. Operations were suspended at this facility on Dec. 31, 2012. While the net book value of the W.N. Clark plant is estimated to be insignificant at the time of retirement, we would reasonably expect any remaining value to be recovered through future rates.

The following table shows 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:

Fuel Source (dollars per megawatt-hour)	2012		2011	2010
Coal	$14.42		$15.89	$12.77
Gas and Oil	$52.08	(a)	$150.00	$131.28
Total Average Fuel Cost	$16.05		$16.77	$13.57
Purchased Power - Coal, Gas and Oil	$26.70		$28.80	$29.57
Purchased Power - Renewable Sources	$47.45		$46.71	$45.76

(a) With the commencement of operations of the 180 megawatt gas-fired units in Pueblo, Colo., and the low price of natural gas compared to oil, the average cost of fuel per MWh decreased.

The following table shows our Electric Utilities' power supply, by resource as a percent of the total power supply for our energy needs:

Power Supply	2012		2011		2010	
Coal	37	%	38	%	42	%
Gas, Oil and Wind	2		—		—	
Total Generated	39		38		42	
Purchased	61		62		58	
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;
- Colorado Electric's PPA with Cargill expiring on Dec. 31, 2013, whereby Colorado Electric purchases 50 megawatts of economy energy;
- 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 between 2013 and 2019. The purchase price related to the option is $2.55 million per megawatt. The purchase price is reduced annually by an amount of annual depreciation assuming a facility life of 35 years;

- 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:

2013-2017	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 March 31, 2013 and a separate agreement whereby Cheyenne Light will receive 40 megawatts of capacity and energy from Basin Electric through March 31, 2013.

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 or fewer kV). We also jointly own high voltage lines with Basin Electric and Powder River Energy Corporation.

At December 31, 2012, 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	592	3,059

Black Hills Power - Jointly Owned (1)	South Dakota, Wyoming	44	—
Cheyenne Light	South Dakota, Wyoming	25	1,229
Colorado Electric	Colorado	236	3,345

(1) Through Black Hills Power, we own 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 degree days, revenue, quantities generated and purchased, quantities sold, and customers for our Electric Utilities:

Degree Days	2012		2011		2010	
	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average
Heating Degree Days:						
Black Hills Power	6,206	(13)%	7,579	5%	7,272	1%
Cheyenne Light	6,304	(11)%	7,321	(1)%	7,033	(5)%
Colorado Electric	4,921	(13)%	5,749	3%	5,518	(1)%
Cooling Degree Days:						
Black Hills Power	937	47%	700	17%	532	(11)%
Cheyenne Light	568	63%	431	58%	345	26%
Colorado Electric	1,322	47%	1,259	37%	1,074	16%

Revenue - Electric (in thousands)	2012	2011	2010
Residential:			
Black Hills Power	$58,523	$59,826	$53,549
Cheyenne Light	32,053	31,287	29,506
Colorado Electric [(a)]	91,550	84,646	76,596
Total Residential	182,126	175,759	159,651
Commercial:			
Black Hills Power	73,858	72,889	65,997
Cheyenne Light	55,600	55,331	52,765
Colorado Electric	82,849	73,355	66,490
Total Commercial	212,307	201,575	185,252
Industrial:			
Black Hills Power	25,656	25,723	22,621
Cheyenne Light	16,105	11,629	10,542
Colorado Electric	37,540	33,332	28,812
Total Industrial	79,301	70,684	61,975
Municipal:			
Black Hills Power	3,268	3,172	3,029
Cheyenne Light	1,807	1,765	1,293
Colorado Electric	13,373	12,912	10,443
Total Municipal	18,448	17,849	14,765
Subtotal Retail Revenue - Electric	492,182	465,867	421,643
Contract Wholesale:			
Total Contract Wholesale - Black Hills Power	20,290	18,105	22,996
Off-system/Power Marketing Wholesale:			
Black Hills Power	31,905	34,889	36,354
Cheyenne Light	8,365	9,371	9,750
Colorado Electric [(b)]	6,003	13,018	10,859
Total Off-system/Power Marketing Wholesale	46,273	57,278	56,963
Other Revenue [(c)]:			
Black Hills Power	29,809	31,027	25,217
Cheyenne Light	2,336	2,449	3,230
Colorado Electric	4,652	2,787	2,374
Total Other Revenue	36,797	36,263	30,821
Total Revenue - Electric	$595,542	$577,513	$532,423

(a) 2012 includes a $2.1 million construction savings incentive.

(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 during 2010 which was all recognized in December 2011.

(c) Other revenue primarily consists of transmission revenue.

Quantities Generated and Purchased (megawatt-hour)	2012	2011	2010
Generated -			
Coal-fired:			
Black Hills Power	1,796,936	1,717,008	1,987,037
Cheyenne Light	587,832	674,518	734,241
Colorado Electric	235,080	268,317	257,896
Total Coal - fired	2,619,848	2,659,843	2,979,174
Gas, Oil and Wind:			
Black Hills Power	33,183	15,221	19,269
Cheyenne Light	—	—	—
Colorado Electric	84,874	2,342	930
Total Gas, Oil and Wind	118,057	17,563	20,199
Total Generated:			
Black Hills Power	1,830,119	1,732,229	2,006,306
Cheyenne Light	587,832	674,518	734,241
Colorado Electric	319,954	270,659	258,826
Total Generated	2,737,905	2,677,406	2,999,373
Purchased -			
Black Hills Power	1,678,090	1,720,640	1,440,579
Cheyenne Light	807,659	745,983	696,756
Colorado Electric	1,794,229	1,948,321	1,969,896
Total Purchased [(a)]	4,279,978	4,414,944	4,107,231
Total Generated and Purchased	7,017,883	7,092,350	7,106,604

(a) Includes wind power of 199,079 MWh, 189,255 MWh and 167,520 MWh in 2012, 2011 and 2010, respectively.

Quantities (megawatt-hour)	2012	2011	2010
Residential:			
Black Hills Power	532,342	550,935	547,193
Cheyenne Light	261,792	264,492	261,607
Colorado Electric	614,521	629,752	628,553
Total Residential	1,408,655	1,445,179	1,437,353
Commercial:			
Black Hills Power	731,785	720,978	720,119
Cheyenne Light	577,141	601,162	603,323
Colorado Electric	723,216	720,060	726,005
Total Commercial	2,032,142	2,042,200	2,049,447
Industrial:			
Black Hills Power	407,301	408,337	382,562
Cheyenne Light	224,448	172,840	161,082
Colorado Electric	358,490	351,862	347,673
Total Industrial	990,239	933,039	891,317
Municipal:			
Black Hills Power	35,933	34,235	33,908
Cheyenne Light	9,631	9,827	6,477
Colorado Electric	121,480	126,320	113,689
Total Municipal	167,044	170,382	154,074
Subtotal Retail Quantity Sold	4,598,080	4,590,800	4,532,191
Contract Wholesale:			
Total Contract Wholesale - Black Hills Power	340,036	349,520	468,782
Off-system Wholesale:			
Black Hills Power	1,263,457	1,226,548	1,163,058
Cheyenne Light	229,062	278,528	311,524
Colorado Electric	160,430	282,929	274,942
Total Off-system Wholesale	1,652,949	1,788,005	1,749,524
Total Quantity Sold:			
Black Hills Power	3,310,854	3,290,553	3,315,622
Cheyenne Light	1,302,074	1,326,849	1,344,013
Colorado Electric	1,978,137	2,110,923	2,090,862
Total Quantity Sold	6,591,065	6,728,325	6,750,497
Losses and Company Use:			
Black Hills Power	197,355	162,316	131,263
Cheyenne Light	93,417	93,652	86,984
Colorado Electric	136,046	108,057	137,860
Total Losses and Company Use	426,818	364,025	356,107

Total Energy Sold	7,017,883	7,092,350	7,106,604

Customers at End of Year	2012	2011	2010
Residential:			
Black Hills Power	55,296	54,955	54,811
Cheyenne Light	35,438	35,159	34,913
Colorado Electric	81,795	81,811	81,902
Total Residential	172,529	171,925	171,626
Commercial:			
Black Hills Power	12,857	12,864	12,779
Cheyenne Light	4,276	4,277	4,132
Colorado Electric	11,220	11,206	11,185
Total Commercial	28,353	28,347	28,096
Industrial:			
Black Hills Power	44	45	40
Cheyenne Light	2	2	2
Colorado Electric	61	68	63
Total Industrial	107	115	105
Other Electric Customers:			
Black Hills Power	308	311	309
Cheyenne Light	240	243	254
Colorado Electric	475	506	510
Total Other Electric Customers	1,023	1,060	1,073
Subtotal Retail Customers	202,012	201,447	200,900
Contract Wholesale:			
Total Contract Wholesale - Black Hills Power	3	3	3
Total Customers:			
Black Hills Power	68,508	68,178	67,942
Cheyenne Light	39,956	39,681	39,301
Colorado Electric	93,551	93,591	93,660
Total Electric Customers at Year-End	202,015	201,450	200,903

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:

	2012	2011	2010
Revenue - Gas (in thousands):			
Residential	$19,327	$22,044	$22,562
Commercial	8,613	10,264	10,801
Industrial	2,715	3,597	3,425
Other Sales Revenue	769	913	803
Total Revenue - Gas	$31,424	$36,818	$37,591
Gross Margin - Gas (in thousands):			
Residential	$10,712	$10,426	$10,004
Commercial	2,963	3,345	3,376
Industrial	551	504	427
Other Gross Margin	766	545	720
Total Gross Margin - Gas	$14,992	$14,820	$14,527
Quantities Sold (Dth):			
Residential	2,215,858	2,585,056	2,636,839
Commercial	1,447,522	1,538,616	1,572,638
Industrial	598,408	689,935	667,062
Total Quantities Sold	4,261,788	4,813,607	4,876,539
Gas Customers at Year-End	35,021	34,807	34,461

Gas Utilities Segment

At Dec. 31, 2012, our Gas Utilities owned the gas transmission and distribution lines by state shown below (in line miles):

	Intrastate Gas Transmission Pipelines	Gas Distribution Mains	Gas Distribution Service Lines
Colorado	124	3,005	896
Nebraska	44	3,451	3,494
Iowa	170	2,747	2,422
Kansas	286	2,664	1,300
Total	624	11,867	8,112

The following tables for our Gas Utilities summarize degree days, revenue, gross margin, volumes sold and customers:

Degree Days

	2012		2011		2010	
	Actual	Variance From 30-Year Average	Actual	Variance From 30-Year Average	Actual	Variance From 30-Year Average
Heating Degree Days:						
Colorado	5,186	(18)%	5,991	(7)%	5,803	(9)%
Nebraska	5,198	(15)%	6,190	(1)%	6,222	—%
Iowa	6,093	(10)%	7,013	(4)%	6,934	(5)%
Kansas [(a)]	4,190	(15)%	4,954	(1)%	4,918	(1)%
Combined [(b)]	5,518	(13)%	6,455	(3)%	6,410	(3)%

(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.

Operating Statistics

Revenue (in thousands)	2012	2011	2010
Residential:			
Colorado	$48,406	$58,102	$55,211
Nebraska	98,339	125,493	120,365
Iowa	82,669	106,292	105,255
Kansas	55,096	65,185	69,859
Total Residential	284,510	355,072	350,690
Commercial:			
Colorado	9,558	12,172	11,880
Nebraska	30,894	40,659	40,720
Iowa	36,550	46,179	46,762
Kansas	15,677	20,362	21,953
Total Commercial	92,679	119,372	121,315
Industrial:			
Colorado	1,963	2,063	1,409
Nebraska	876	860	3,126
Iowa	2,458	2,521	2,243
Kansas	13,614	19,571	14,312
Total Industrial	18,911	25,015	21,090
Other Sales Revenue:			
Colorado	181	96	97
Nebraska	2,066	1,971	1,960
Iowa	452	550	836
Kansas	5,124	3,031	3,451
Total Other Sales Revenue	7,823	5,648	6,344
Distribution:			
Colorado	60,108	72,433	68,597
Nebraska	132,175	168,983	166,171
Iowa	122,129	155,542	155,096
Kansas	89,511	108,149	109,575
Total Distribution	403,923	505,107	499,439
Transportation:			
Colorado	866	846	784
Nebraska	10,589	11,175	11,289
Iowa	4,128	3,935	3,708
Kansas	5,762	5,909	5,471
Total Transportation	21,345	21,865	21,252
Total Regulated Revenue	425,268	526,972	520,691
Non-regulated Services	28,813	27,612	30,016

Total Revenue	$454,081	$554,584	$550,707

Gross Margin (in thousands)	2012	2011	2010
Residential:			
Colorado	$16,400	$17,711	$18,153
Nebraska	46,982	51,640	49,074
Iowa	39,561	47,491	44,269
Kansas	28,734	29,701	29,591
Total Residential	131,677	146,543	141,087
Commercial:			
Colorado	2,680	2,960	3,215
Nebraska	10,201	11,643	11,965
Iowa	11,071	11,702	11,616
Kansas	6,097	6,603	6,544
Total Commercial	30,049	32,908	33,340
Industrial:			
Colorado	581	450	360
Nebraska	249	217	379
Iowa	257	288	235
Kansas	2,362	2,373	1,878
Total Industrial	3,449	3,328	2,852
Other Sales Margins:			
Colorado	181	96	97
Nebraska	2,066	1,971	1,960
Iowa	452	549	836
Kansas	4,787	2,455	2,722
Total Other Sales Margins	7,486	5,071	5,615
Distribution:			
Colorado	19,842	21,217	21,825
Nebraska	59,498	65,471	63,378
Iowa	51,341	60,030	56,956
Kansas	41,980	41,132	40,735
Total Distribution	172,661	187,850	182,894
Transportation:			
Colorado	866	846	784
Nebraska	10,589	11,175	11,289
Iowa	4,128	3,935	3,708
Kansas	5,762	5,909	5,470
Total Transportation	21,345	21,865	21,251
Total Regulated Gross Margin:			
Colorado	20,708	22,063	22,609
Nebraska	70,087	76,646	74,667
Iowa	55,469	63,965	60,664

Kansas	47,742	47,041	46,205
Total Regulated Gross Margin	194,006	209,715	204,145
Non-regulated Services	14,726	12,908	12,845
Total Gross Margin	$208,732	$222,623	$216,990

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Quantities Sold (in Dth)	2012	2011	2010
Residential:			
Colorado	5,869,817	6,437,860	6,284,559
Nebraska	9,555,073	12,076,979	12,210,574
Iowa	8,732,301	10,490,129	10,556,045
Kansas	5,681,199	6,853,163	6,926,928
Total Residential	29,838,390	35,858,131	35,978,106
Commercial:			
Colorado	1,284,082	1,472,747	1,473,924
Nebraska	3,952,067	4,833,604	5,009,105
Iowa	5,304,162	6,192,167	6,061,954
Kansas	2,121,063	2,676,439	2,673,805
Total Commercial	12,661,374	15,174,957	15,218,788
Industrial:			
Colorado	463,566	344,576	259,985
Nebraska	158,445	120,779	544,457
Iowa	492,633	409,723	354,435
Kansas	3,675,678	3,743,735	2,718,767
Total Industrial	4,790,322	4,618,813	3,877,644
Other:			
Colorado	—	—	—
Nebraska	—	—	1,341
Iowa	—	—	69,306
Kansas	68,419	112,253	120,445
Total Other	68,419	112,253	191,092
Distribution:			
Colorado	7,617,465	8,255,183	8,018,468
Nebraska	13,665,585	17,031,362	17,765,477
Iowa	14,529,096	17,092,019	17,041,740
Kansas	11,546,359	13,385,590	12,439,945
Total Distribution	47,358,505	55,764,154	55,265,630
Transportation:			
Colorado	850,156	869,570	808,859
Nebraska	26,649,759	24,972,560	27,327,173
Iowa	18,294,228	18,358,692	17,422,525
Kansas	14,686,679	15,015,310	14,320,893
Total Transportation	60,480,822	59,216,132	59,879,450
Total Volumes Sold:			
Colorado	8,467,621	9,124,753	8,827,327
Nebraska	40,315,344	42,003,922	45,092,650
Iowa	32,823,324	35,450,711	34,464,265
Kansas	26,233,038	28,400,900	26,760,838

Total Quantities Sold	107,839,327	114,980,286	115,145,080

Customers	2012	2011	2010
Residential:			
Colorado	68,927	67,496	66,766
Nebraska	176,953	176,386	176,244
Iowa	135,897	135,161	134,782
Kansas	98,516	98,043	97,844
Total Residential	480,293	477,086	475,636
Commercial:			
Colorado	3,681	3,678	3,620
Nebraska	15,626	15,664	15,221
Iowa	15,398	15,398	15,300
Kansas	9,584	9,453	9,469
Total Commercial	44,289	44,193	43,610
Industrial:			
Colorado	213	209	208
Nebraska	136	141	149
Iowa	94	94	93
Kansas	1,261	1,365	1,394
Total Industrial	1,704	1,809	1,844
Transportation:			
Colorado	36	30	22
Nebraska	4,115	4,128	4,270
Iowa	412	393	392
Kansas	1,166	1,142	1,054
Total Transportation	5,729	5,693	5,738
Other:			
Colorado	—	—	—
Nebraska	—	—	2
Iowa	—	—	68
Kansas	7	7	8
Total Other	7	7	78
Total Customers:			
Colorado	72,857	71,413	70,616
Nebraska	196,830	196,319	195,886
Iowa	151,801	151,046	150,635
Kansas	110,534	110,010	109,769
Total Customers at Year-End	532,022	528,788	526,906

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 our costs, 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 certain enacted regulatory information with respect to the states in which the Utilities Group operate:

Subsidiary	Jurisdic-tion	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Capital Structure Debt/Equity	Effective Date	Tariff and Rate Matters	Percentage of Power Marketing Activity Shared with Customers
Electric Utilities:							
Black Hills Power	SD	Global Settlement	8.6%	Global Settlement	4/2010	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%	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%	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%	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%	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%	12/2012	GCA, Energy Efficiency Cost Recovery/ DSM	NA
Nebraska Gas	NE	10.1%	9.1%	48%/52%	9/2010	GCA, Cost of Bad Debt Collected through GCA	NA
Kansas Gas	KS	Global Settlement	Global Settlement	49.3%/50.7%	10/2007	GCA, Weather Normalization Tariff, Gas System Reliability Surcharge, Ad Valorem Tax Surcharge, Cost of Bad Debt Collected through GCA	NA
Iowa Gas	IA	Global Settlement	Global Settlement	Global Settlement	2/2011	GCA, Energy Efficiency Cost Recovery/DSM	NA

We produce and/or distribute energy 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 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 October 2012, the WPSC approved Cheyenne Prairie’s construction financing rider which allows for recovery of construction financing costs from customers during the construction period in lieu of traditional AFUDC. The rider was implemented Nov. 1, 2012 and will allow Cheyenne Light and Black Hills Power to earn and collect a rate of return during the construction period on approximately 60 percent of the total project cost that relates to Wyoming customers, while also saving customers money over the long-term. This will increase gross margin by approximately $5.5 million and $7.8 million in 2013 and 2014, respectively.

- 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 was eliminated and the sharing mechanism was modified to 85 percent to the customer.

- In South Dakota, beginning April 1, 2010, 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, as of April 1, 2010, the ECA was modified in the rate case settlement to contain 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 beginning June 1, 2010 a similar Fuel and Purchased Power Cost Adjustment was instituted.

- In South Dakota, we have an approved annual Environmental Improvement Cost Recovery Adjustment tariff that went into effect June 1, 2011 and 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. The revenue requirement is based on an equity return of 10.8 percent, a capital structure of 57 percent equity and 43 percent debt, and a return on rate base which is adjusted annually.

- In Colorado, we have an ECA for semi-annual increases or decreases in purchased power and fuel costs and a TCA for transmission costs. The ECA provides for the direct recovery of increased purchased power and fuel costs or the issuance of credits for decreases in purchased power, environmental generation and fuel costs. The TCA is an annual rider to the customer’s bill which allows the utility to earn an authorized return on new transmission investment and recovery of operations and maintenance costs related to transmission. Effective Jan. 1, 2012, the CPUC approved adjustments to the ECA. These adjustments allow for the recovery of transmission expenses paid to other providers, symmetrical interest, and the sharing of off-system sales margins, less certain operating costs, where the customer receives 75 percent through 2013. This sharing percentage increases to 90 percent to the customer in 2014 and thereafter.

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. Some of the mechanisms we have in place are:

- 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.

Pending Rates

The following summarizes certain state and federal rate cases, riders and surcharges with activity occurring in 2012 (dollars in millions):

	Type of Service	Date Requested	Revenue Amount Requested
Iowa Gas [1]	Gas	12/2012	$0.9
Black Hills Power [2]	Electric	12/2012	$13.7
Black Hills Power [3]	Electric	12/2012	$9.2

(1) Iowa Gas filed a request for a Capital Infrastructure Automatic Adjustment Mechanism with the IUB in December 2012. If approved, the adjustment could result in a revenue increase of $0.9 million in 2013 which reflects a request for recovery of costs since our prior rate case in 2010. Also if approved, an adjustment request will be required to be filed annually thereafter and subsequent filings will vary in size based on eligible infrastructure replacements and the timing of future general rate case filings. The filing is currently under review by the IUB.

(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. Black Hills Power has requested an effective date of April 1, 2013. A decision is anticipated during the third quarter of 2013. If the SDPUC has not reached a decision within 180 days, interim rates will go into effect 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 would be similar to the one approved by the WPSC 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, subject to refund. The rider will allow 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. If approved, this will increase gross margin by approximately $3.6 million and $5.6 million in 2013 and 2014, respectively. We anticipate a final ruling by the SDPUC on this rider during the third quarter of 2013.

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, 2012, we were subject to the following renewable energy portfolio standards or objectives:

- Colorado. Colorado has adopted a renewable energy standard that requires 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 law limits the net annual incremental retail rate impact from these renewable resource acquisitions (as compared to non-renewable resources) to 2 percent and 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, and our current strategy is to incorporate renewable energy as required to comply with the standards going forward however, the 2 percent limitation may prohibit us from reaching the percentages set forth in the standards.

- Montana. Montana established a renewable portfolio standard that requires Black Hills Power to obtain a percentage of its retail electric sales in Montana from eligible renewable resources according to the following schedule: (i) 10 percent for compliance through 2014; and (ii) 15 percent for compliance year 2015 and thereafter. Utilities can meet this standard by entering into long-term purchase contracts for electricity bundled with renewable-energy credits, by purchasing the renewable-energy credits separately, or by a combination of both. The law includes cost caps that limit the additional cost utilities must pay for renewable energy and allows cost recovery from customers for contracts pre-approved by the MTPSC. We are currently in compliance with applicable standards, and our current strategy is to incorporate renewable energy as required to comply with the standards.

- 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. Absent a specific renewable energy mandate in South Dakota, our current strategy is to prudently incorporate renewable energy into our resource supply, seeking to minimize associated rate increases for our utility customers.

- Wyoming. Wyoming is exploring the implementation of renewable energy portfolio standards but has not currently adopted standards.

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 ratemaking 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 gave FERC authority 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)
2013	$ 3.3
2014	2.1
2015	0.8
Total	$ 6.2

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 was scheduled to propose updated regulations for wastewater discharge from power generators by Dec. 14, 2012, with a scheduled implementation date of May 2014. However, in December 2012, the proposed rule deadline was extended to April 19, 2013. These rules may have a significant impact on our coal-fired units. Additionally, the EPA regulates surface water oil pollution through its oil pollution prevention regulations. All of our facilities under this program have their required 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 program as part of the federal acid rain program. Each allowance gives the owner the right to emit one ton of SO_2, and certain facilities are allocated allowances based on their historical operating data. At the end of each year, each emitting unit must have enough allowances to cover its emissions for the year just ended. Allowances may be traded so affected units that expect to emit more SO_2 than their allocated allowances may purchase allowances in 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 and Wyodak plants. Without purchasing additional allowances, we currently hold sufficient allowances to satisfy Title IV at all such plants through 2042. 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. Wygen III is allowed to operate under its 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 2013. The application was 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. In anticipation of this rule and our evaluation of costs to retrofit these plants, we suspended operations at the Osage plant in October 2010 and as a result of this rule, we suspended operations at the Ben French facility on Aug. 31, 2012 with plans to 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. This facility suspended operations Dec. 31, 2012.

On February 16, 2012, the EPA published in the Federal Register the National Emission Standards for Hazardous Air Pollutants from Coal and Oil Fired Electric Utility Steam Generating Units (MATS), with an effective date of April 16, 2012. This rule imposes requirements for mercury, acid gases, metals and other pollutants. Affected units will have three years from the rule effective date to be in compliance, with a pathway defined to apply for a one year extension due to certain 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. Wygen II has been utilized for internal study and review of mercury emission control technology and has mercury monitors in place. In 2009, we added mercury monitors to our Neil Simpson II plant. The Wygen III plant, which commenced operations in 2010, also has mercury monitors. Neil Simpson II, Wygen II, Wygen III and the Wyodak plant are expected to be in compliance by the compliance deadline, without incurring significant costs.

On June 23, 2010, the EPA published in the Federal Register 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 of a new major source as defined by EPA regulations. Existing permitted facilities will see monitoring and reporting requirements incorporated into their operating permits upon renewal. New projects or major modifications to existing projects will result in a Best Available Control Technology review that could result in more stringent emission control practices and technologies. As Wyoming state law prohibits regulation of GHG, the EPA will review and develop requirements for that portion of a new source construction permit or for a major modification of an existing source. This additional process will increase the time and expense for the permitting process. In addition, unlike a Wyoming issued permit, an appeal of an EPA issued GHG air permit to construct requires an automatic stay to the project, meaning that construction cannot commence until the appeal is resolved. This aspect adds considerable risk to new construction projects as well as to major modifications to existing projects. Wyoming has been working to modify this statute and implement GHG regulations. It is anticipated that EPA will approve Wyoming’s GHG program by the spring of 2014.

On April 13, 2012, the EPA proposed Electric Utility New Source Performance Standards for GHG. These standards will apply to Cheyenne Prairie. They are scheduled to be final in the first half of 2013 and, as proposed, would not have a significant impact on this project. However, until we can evaluate the final version, we cannot be certain of this assumption.

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 2013 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 must comply with the EPA’s Stationary Reciprocating Internal Combustion Engine Hazardous Air Pollutant regulations. Evaluations have been completed and emission control equipment is being installed to meet that deadline.

The EPA is expected to propose a more stringent ozone ambient air standard in 2013. 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. On Dec. 14, 2012 EPA signed revisions to the Particulate Matter 2.5 annual ambient air quality standard, lowering the annual limit from 15 to 12 ug/m^3. EPA's website indicates that all counties where we currently have power generation facilities are expected to be able to comply with the new standard. This action is expected to result in more restrictive particulate matter emission limitations on any new construction and major modifications to our existing units.

In 2011, the State of Wyoming issued a letter requiring Neil Simpson II to include startup and shutdown SO_2 & NO_x emissions when evaluating compliance with permitted emission limits. This represented a significant change from requirements in the original 1993 air permit. Some minor engineered design changes were made to enable improved scrubber performance during startup and those changes have been successful in enabling the unit to meet the new requirements. The unit was previously fitted with state of the art low NO_x burners that enable compliance with this new requirement. 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. It is our expectation Ben French, Osage and Neil Simpson I will be permanently retired on or prior to March 21, 2014; however, if not retired, it is highly probable these plants along with Neil Simpson II, will 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 of the intents 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. This Act had a significant impact on our W.N. Clark facility and on Dec. 15, 2010, the CPUC issued an order approving closure of the W.N. Clark plant by Dec. 31, 2013. On Jan. 7, 2011, the State Air Quality Control Commission adopted the CPUC order into the Colorado State Implementation Plan and in the Dec. 31, 2012 Federal Register, EPA Region VIII gave full approval to that plan, establishing the closure of W.N. Clark as a federally approved state regulation and as such is now federally enforceable.

A number of our power plants have been subject to new state and EPA regulations issued in the last couple of 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 planned retirements for the following plants:

Plant	Company	Megawatts	Type of Plant	Date Suspended	Planned 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	to be determined	71
Pueblo Unit #6	Colorado Electric	20.0	Gas	Dec. 31, 2012	to be determined	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.

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 is intending to finalize the first GHG emission standards sometime in the first half of 2013, which will be applicable 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. 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 2013 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 2012, 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. 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 future 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 filed with the State of Wyoming on Nov. 3, 2010 and approved on April 13, 2012. Site closure work is underway with post closure monitoring to continue for 30 years. If Osage should ever re-start, ash disposal will be at our WRDC coal mine.

As of Aug. 31, 2012, we suspended operations at Ben French which is scheduled to close on or before March 21, 2014. We have also announced plans to close Neil Simpson I on or before March 21, 2014.

Our W.N. Clark plant which suspended operations on Dec. 31, 2012 and is scheduled to be retired by Dec. 31, 2013, sends 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, CO, we have 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 disposed of such waste responsible for remedial treatment. On June 21, 2010, the EPA published in the Federal Register the proposed coal combustion residuals regulations. The regulations are complex and contain various options for ash management that the EPA will be selecting 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 2013. However, 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 $1.1 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) and the successor would be 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, however there is a potential for additional minimal remediation work at Plattsmouth. If required, it is expected to be completed by mid-2013. Both Nebraska sites will be required to monitor groundwater quality for a minimum two year period.

As of Dec. 31, 2012, we estimate a range of approximately $2.9 million to $6.3 million to remediate these MGP sites in both Nebraska and Iowa.

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

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

For more than 15 years, 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, our Energy Marketing segment, which resulted in this segment being classified as discontinued operations. For comparative purposes, all prior periods presented have been restated to reflect the reclassification of this segment as discontinued operations.

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, 2012, we held varying interests in independent power plants operating in Wyoming and Colorado with a total net ownership of 309 MW.

Portfolio Management

We sell capacity and energy 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, 2012, 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.

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 3-year PPA that expires in August 2014. We are exploring various alternatives for the Gillette CT following expiration of its contract with Cheyenne Light, including contracting or selling the unit to another party. We sell excess power from our generating capacity into the wholesale power markets when it is available and economical.

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. 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 between 2013 and 2019. The purchase price in the contract related to the option is $2.6 million per megawatt reduced annually by an amount of annual depreciation assuming a facility life of 35 years. 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 facility 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, Colorado Electric has the ability to utilize our generating plants to sell energy in the wholesale power markets when it is available and economical.

Operating Agreement. 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 Facility. Our EWGs have been 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 2042, 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. Also, as the EPA regulates surface water oil pollution prevention through its oil pollution prevention regulations, each of our facilities regulated under this program have the requisite 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 Facility, 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 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 4.2 million tons of coal in 2012.

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 haul trucks and conveyors to transport the coal to the mine-mouth generating facility. 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 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. We expect a lower overburden ratio for the next several years.

Mining rights to the coal are based on four federal leases and one state lease. The federal leases expire between Sept. 30, 2015 - March 31, 2021 and the state lease expires on Aug. 1, 2013. 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, 2012, we estimated our recoverable coal reserves to be approximately 232.3 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 46 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:

- our electric utilities, Black Hills Power and Cheyenne Light. During 2012, Black Hills Power suspended operations at the 25 megawatt Ben French plant effective on Aug. 31, 2012 and announced the retirement of the Ben French plant and the 21.8 megawatt Neil Simpson I plant effective March 21, 2014 to which we sell approximately 120,000 and 130,000 tons of coal per year, respectively;

- 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 600,000 tons of coal each year. This contract expires at the end of June 2038; and
- certain regional industrial customers served by truck to which we sell approximately 165,000 tons of coal each year. These contracts are short-term and have a 1-3 year time range.

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 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 costs 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 Wyodak 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.

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 related 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 South Dakota and 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. The public comment period ended in November 2010, and a final rule is expected in 2013. 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 $20.3 million for reclamation costs as of Dec. 31, 2012. 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 primarily in the Rocky Mountain region.

As of Dec. 31, 2012, 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 (including 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 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, 2012, we had total reserves of approximately 81 Bcfe, of which natural gas comprised 69 percent and crude oil comprised 31 percent. The majority of our reserves are located in select crude oil and natural gas producing basins in the Rocky Mountain region. Approximately 36 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; 35 percent are located in the Powder River Basin of Wyoming, primarily in the Finn-Shurley Field of Weston and Niobrara counties; and 15 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 21 to the Consolidated Financial Statements in this Annual Report on Form 10-K.

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

CG&A is a Texas Registered Engineering Firm. Our primary contact at CG&A is Mr. Zane Meekins. Mr. Meekins has been practicing consulting petroleum engineering since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas and has over 24 years of practical experience in petroleum engineering and over 22 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 32 years of exploration and production industry experience as a geologist and financial analyst. He has over 22 years of experience working closely with internal and third party qualified reserve estimators in major and mid-sized oil and gas companies. He 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, 2012, 2011 and 2010:

Proved Reserves		Dec. 31, 2012				
	Total	Piceance	San Juan	Williston [(a)]	Powder River	Other
Developed -						
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 (MMcfe)	77,192	11,855	28,231	3,754	27,481	5,871
Undeveloped -						
Natural Gas (MMcf)	1,901	335	457	279	186	644
Oil (Mbbl)	265	—	—	187	78	—
Total Undeveloped (MMcfe)	3,491	335	457	1,401	654	644
Total MMcfe	80,683	12,190	28,688	5,155	28,135	6,515

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

Proved Reserves		Dec. 31, 2011				
	Total	Piceance	San Juan	Williston	Powder River	Other
Developed -						
Natural Gas (MMcf)	71,867	15,598	36,463	1,954	8,926	8,926
Oil (Mbbl)	4,830	—	12	1,247	3,549	22
Total Developed (MMcfe)	100,847	15,598	36,535	9,436	30,220	9,058
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

Proved Reserves		Dec. 31, 2010				
	Total	Piceance	San Juan	Williston	Powder River	Other
Developed -						
Natural Gas (MMcf)	67,656	11,475	36,281	679	10,180	9,041
Oil (Mbbl)	4,434	—	11	508	3,891	24
Total Developed (MMcfe)	94,260	11,475	36,347	3,727	33,526	9,185
Undeveloped -						
Natural Gas (MMcf)	27,800	21,777	620	1,820	—	3,583
Oil (Mbbl)	1,506	—	—	1,506	—	—
Total Undeveloped (MMcfe)	36,836	21,777	620	10,856	—	3,583
Total MMcfe	131,096	33,252	36,967	14,583	33,526	12,768

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, 2012, 2011 and 2010:

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

	December 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 during 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 (sales)	(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 (sales)	—	—	—	—	—	—
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 (sales)	(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

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(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.

Crude Oil	Dec. 31, 2010					
(in Mbbl)	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	5,274	—	7	678	4,552	37
Production	(376)	—	(2)	(84)	(280)	(10)
Additions - acquisitions	(13)	—	—	—	—	(13)
Additions - extensions and discoveries	1,145	—	—	1,099	46	—
Revisions to previous estimates	(90)	—	6	321	(427)	10
Balance at end of year	5,940	—	11	2,014	3,891	24

Natural Gas	Dec. 31, 2010					
(in MMcf)	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	87,660	19,301	42,306	1,005	11,171	13,877
Production	(8,484)	(1,077)	(5,056)	—	(314)	(2,037)
Additions - acquisitions	(377)	—	—	—	—	(377)
Additions - extensions and discoveries	1,710	—	372	1,334	—	4
Revisions to previous estimates	14,947	15,028	(721)	160	(677)	1,157
Balance at end of year	95,456	33,252	36,901	2,499	10,180	12,624

Total MMcfe [a]	Dec. 31, 2010 Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	119,304	19,301	42,348	5,073	38,483	14,099
Production	(10,740)	(1,077)	(5,068)	(504)	(1,994)	(2,097)
Additions - acquisitions	(455)	—	—	—	—	(455)
Additions - extensions and discoveries	8,580	—	372	7,928	276	4
Revisions to previous estimates [b]	14,407	15,028	(685)	2,086	(3,239)	1,217
Balance at end of year	131,096	33,252	36,967	14,583	33,526	12,768

(a) Production for reserve calculations does not include volumes for NGLs.
(b) Revisions to previous estimates for 2010 are primarily due to price changes.

Production Volumes

Location	Year ended Dec. 31, 2012 Oil (in Bbl)	Natural Gas (Mcfe) [a]	Total (Mcfe)
San Juan	1,423	4,923,589	4,932,127
Piceance	—	1,751,494	1,751,494
Powder River	218,455	837,552	2,148,282
Williston [b]	337,579	427,258	2,452,732
All other properties	2,514	1,244,228	1,259,313
Total Volume	559,971	9,184,121	12,543,948

(a) Includes NGLs.
(b) Reflects sale of the majority of our Williston Basin assets during 2012.

Location	Year ended Dec. 31, 2011 Oil (in Bbl)	Natural Gas (Mcfe) [a]	Total (Mcfe)
San Juan	1,746	5,062,662	5,073,138
Piceance	—	1,111,421	1,111,421
Powder River	264,358	942,573	2,528,721
Williston	181,580	172,949	1,262,429
All other properties	4,139	1,761,788	1,786,622
Total Volume	451,823	9,051,393	11,762,331

(a) Includes NGLs.

Location	Year ended Dec. 31, 2010 Oil (in Bbl)	Natural Gas (Mcfe) [a]	Total (Mcfe)
San Juan	2,403	5,055,635	5,070,053
Piceance	—	1,111,724	1,111,724
Powder River	280,351	842,385	2,524,491
Williston	84,472	—	506,832
All other properties	8,419	2,036,755	2,087,269
Total Volume	375,645	9,046,499	11,300,369

(a) Includes NGLs.

Other Information

	As of Dec. 31, 2012	As of Dec. 31, 2011
Proved developed reserves as a percentage of total proved reserves on an MMcfe basis	98 %	76 %
Proved undeveloped reserves as a percentage of total proved reserves on an MMcfe basis [(a)]	2 %	24 %
Present value of estimated future net revenues, before tax, discounted at 10 percent (in thousands)	$151,255	$255,087

(a) The decrease to proved undeveloped reserves is primarily due to commodity price changes. See Note 21 in the accompanying Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for further details.

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

	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

	Dec. 31, 2010					
	Total	Piceance	San Juan	Williston	Powder River	Other
Gas per Mcf	$3.45	$3.21	$3.50	$3.57	$3.62	$3.79
Oil per Bbl	$70.82	$—	$66.36	$69.32	$71.62	$68.52

Drilling Activity

In 2012, we participated in drilling 52 gross (4 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,	2012		2011		2010	
Net Development Wells	Productive	Dry	Productive	Dry	Productive	Dry
Piceance	—	—	—	—	—	—
San Juan	—	—	1.00	—	5.60	—
Williston	1.80	—	1.73	—	0.67	—
Powder River	0.74	0.19	—	—	2.66	—
Other	—	—	3.59	—	—	—
Total net development wells	2.54	0.19	6.32	—	8.93	—

Year ended Dec. 31,	2012		2011		2010	
Net Exploratory Wells	Productive	Dry	Productive	Dry	Productive	Dry
Piceance	0.86	—	0.99	—	—	—
San Juan	—	—	0.80	—	—	—
Williston	—	—	—	—	—	—
Powder River	—	—	—	—	—	—
Other	—	—	0.25	1.70	—	—
Total net exploratory wells	0.86	—	2.04	1.70	—	—

As of Dec. 31, 2012, we were participating in the drilling of 16 gross (0.50 net) wells, which had been commenced but not yet completed.

Recompletion Activity

Recompletion activities for the years ended Dec. 31, 2012, 2011 and 2010 were insignificant to our overall oil and gas operations.

Productive Wells

The following table summarizes our gross and net productive wells at December 31, 2012, 2011 and 2010:

		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

	Dec. 31, 2010					
	Total	Piceance	San Juan	Williston	Powder River	Other
Gross Productive:						
Crude Oil	463	1	2	38	418	4
Natural Gas	828	88	225	—	7	508
Total	1,291	89	227	38	425	512
Net Productive:						
Crude Oil	312.09	—	1.91	2.46	307.23	0.49
Natural Gas	355.90	66.23	214.82	—	0.73	74.12
Total	667.99	66.23	216.73	2.46	307.96	74.61

Acreage

The following table summarizes our undeveloped, developed and total acreage by location as of Dec. 31, 2012:

	Undeveloped		Developed		Total	
	Gross	Net [a]	Gross	Net	Gross	Net
Piceance	69,562	47,588	37,326	33,226	106,888	80,814
San Juan	40,677	39,273	25,213	23,024	65,890	62,297
Williston [b]	3,670	[b] 524	12,860	1,853	16,530	2,377
Powder River	130,871	72,436	31,612	16,425	162,483	88,861
Bear Paw Uplift (MT)	355,103	96,913	106,650	19,796	461,753	116,709
Other	23,281	11,902	27,524	4,798	50,805	16,700
Total	623,164	268,636	241,185	99,122	864,349	367,758

(a) Approximately 13.3 percent (129,316 gross and 35,724 net acres), 7.3 percent (71,758 gross and 19,716 net acres) and 15.9 percent (81,944 gross and 42,796 net acres) of our undeveloped acreage could expire in 2013, 2014 and 2015, 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 during 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 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 we estimate to be mid-2013. 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, state air quality permits and underground injection control disposal permits), chemical storage and use and the remediation of petroleum-product contamination. 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 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. 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 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. Also in 2012, the U.S. Department of the Interior proposed rules regulating the use of hydraulic fracturing. Action on these proposed rules is expected in 2013. 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. Those include emission standards for reciprocating internal combustion engines, 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.

Our policy is to meet or exceed all applicable local, state, tribal and federal regulatory requirements when drilling, casing, and cementing oil and 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.

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 have qualified companies monitoring 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 published an amendment to its GHG reporting requirements in the November 2010 Federal Register, 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

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, 67,000 square foot office building where our corporate headquarters is located, an office building consisting of approximately 36,000 square feet, and a warehouse building and shop with approximately 30,410 square feet.
- In Pueblo, Colo., we own approximately 22,600 square feet for a service center and approximately 25,700 square feet for a warehouse.
- In Cheyenne, Wyo., we own a business office with approximately 13,400 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 and warehouse space totaling over 196,200 square feet utilized by our Gas Utilities.
- In South Dakota, Wyoming, Colorado and Montana we own various office, service center and warehouse space totaling approximately 56,000 square feet utilized by our Electric Utilities.
- In our service territories, we also own other offices and warehouses.

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 47,400 square feet of office space in Denver, Colo., of which 10,100 square feet is subleased to a third party;
- Approximately 111,000 square feet of various office, service center and warehouse space leased by the Gas Utilities;
- Approximately 3,600 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. Similarly, the assets of Black Hills Wyoming are pledged to their lenders under a mortgage and security agreements for real and personal property.

Employees

At December 31, 2012, we had 1,925 full-time employees. Approximately 33 percent of our employees are represented by a collective bargaining agreement. We have not experienced any labor stoppages in recent years. At Dec. 31, 2012, 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	363
Utilities	1,415
Non-regulated Energy	147
Total	1,925

At Dec. 31, 2012, certain of our Utilities Group employees were covered by the following collective bargaining agreements:

Utility	Union Affiliation

	Number of Employees		Expiration Date of Collective Bargaining Agreement
Black Hills Power	148	IBEW Local 1250	March 31, 2017
Cheyenne Light	50	IBEW Local 111	June 30, 2016
Colorado Electric	129	IBEW Local 667	April 15, 2015
Iowa Gas	134	IBEW Local 204	July 31, 2015
Kansas Gas	20	Communications Workers of America, AFL-CIO Local 6407	Dec. 31, 2014
Nebraska Gas	147	IBEW Local 244	March 13, 2014
Total	628		

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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 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; and
- Competition within our industry and with producers of competing energy sources.

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 Groups' 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;
- 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 33 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;
- 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 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 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, 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 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 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. Combined with lower demand from the economic downturn, this new and abundant supply source has created record volumes of natural gas in storage, and reduced domestic natural gas prices. In fact, the ratio of crude oil to natural gas prices is at an all-time high, far in excess of the six to one heating value equivalent ratio. This trend is likely to continue for the foreseeable future given the expected further development of domestic shale gas reserves.

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 on our financial results.

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 can increasingly impose significant civil penalties to enforce compliance requirements relative to our business. In addition, FERC has 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 did occur, 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.

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 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 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 $353.4 million of goodwill on our consolidated balance sheet as of December 31, 2012. 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 and interest rates, regulatory, industry or market conditions, changes in business operations, changes in competition or changes in technologies. Any changes in key assumptions, or actual performance compared with key assumptions, about our business and its future prospects could affect the fair value of one or more business segments, which may result in an impairment charge.

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

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

Coal Mining

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

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

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

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

Oil and Gas

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

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

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

Hydraulic fracturing is an essential and common practice in the oil and gas industry used extensively for decades to stimulate production of natural gas and/or oil from dense subsurface rock formations. We routinely apply hydraulic fracturing techniques on our crude oil and natural gas properties. Hydraulic fracturing involves using mostly water, sand, and a small amount of certain chemicals to fracture the hydrocarbon-bearing rock formation to enhance flow of hydrocarbons into the well-bore. The process is typically regulated by state crude oil and natural gas commissions; however, the EPA does assert federal regulatory authority over certain hydraulic fracturing activities when diesel comprises part of the fracturing fluid. In addition several agencies of the federal government including the EPA and the BLM are conducting studies of the fracturing stimulation process which may result in additional regulations. In 2012 the BLM has proposed regulations governing the use of hydraulic fracturing. 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 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 Baa3 (Positive outlook) by Moody's; BBB- (Positive outlook) by S&P; and BBB- (Stable outlook) by Fitch. Reduction of our credit ratings could impair our ability to refinance or repay our existing debt and to complete new financings on acceptable 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, given that we are a holding company and that 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.

The continued recessionary environment and any 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, wildfire-related liability, 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 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 currently stated in a Notice of Proposed Adjustment received from the IRS in January 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 $20 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.

Our ability to successfully resolve the purchase price adjustments in question from the sale of Enserco.

On Feb. 29, 2012, we sold the outstanding stock of Enserco, our Energy Marketing segment. Pursuant to the provisions of the Stock Purchase Agreement, disputes regarding post-closing purchase price adjustments are subject to arbitration before a nationally-recognized accounting firm and all other disputes are subject to the indemnification procedures in the agreement. The buyer originally demanded an amount totaling $7.2 million characterizing all claims in such demand as purchase price adjustments. We contested certain claims in the buyer's demand, including whether certain claims were properly characterized as purchase price adjustments, but reached a partial settlement and paid the buyer the sum of $1.4 million. The parties were unable to reach a negotiated agreement regarding the balance of the claims.

In December 2012, we agreed to arbitrate the claims that we believe are properly characterized as purchase price adjustments, but objected to the arbitration of the claims that we believe are not properly characterized as purchase price adjustments. After joint discussions of the parties with the arbitrator, in January 2013 the arbitrator advised the parties that it would not arbitrate the claims to which we objected. On Feb. 7, 2013, the buyer filed a petition in the United States District Court for the District of Colorado applying for an order compelling arbitration on all of the disputed claims. We will respond to this litigation, requesting the court to deny the buyer's application.

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 have been completed and confirm the significant impact on our Neil Simpson I, Osage and Ben French facilities. We anticipate these units will be retired on or before March 21, 2014 compliance deadline.

On Dec. 16, 2011, with updates on Dec. 21, 2012, the EPA signed the National Emission Standards for Hazardous Air Pollutants from Coal and Oil Fired Electric Utility Steam Generating Units (MATS), which became effective on April 16, 2012. Affected units have three years from the rule effective date to be in compliance, 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 with the need to install mercury sorbent injection systems and the need to meet additional monitoring and testing.

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. Existing permitted facilities will see monitoring reporting requirements incorporated into their operating permits upon renewal. New projects or major modifications to existing projects will result in a Best Available Control Technology review that could result in more stringent emissions control practices and technologies. The EPA's GHG New Source Performance Standard for new steam electric generating units is expected to be final in the first half of 2013 and as proposed, effectively prohibits new coal fired units until carbon capture and sequestration becomes technically and economically feasible. In 2013, we expect to see a proposed rule from the EPA, to regulate GHG emissions from existing steam electric generating units. This rule could have a significant impact on our coal generating fleet.

In 2010, the State of Colorado enacted House Bill 1365, the Colorado Clean Air, Clean Jobs Act, a coordinated utility plan to reduce air emissions from coal fired power plants and promoting the use of natural gas and other lower emitting resources. This act has a significant impact on our W.N. Clark facility and in October 2010, Colorado Electric filed testimony with the CPUC that recommended retirement of the W.N. Clark facility to comply with House Bill 1365. In December 2010, the CPUC issued an order approving the closure of the W.N. Clark generation facility by Dec. 31, 2013, and granted a presumption of need for replacement of the plant. On July 30, 2012, Colorado Electric filed its electric resource plan with the CPUC seeking to develop and own replacement capacity for the retirement of the coal-fired W.N. Clark power plant. The CPUC dismissed the initial filing without prejudice. It directed Colorado Electric to refile the resource plan and address alternatives for not just the replacement capacity for its coal-fired W.N. Clark power plant, but also for the retirement of the aging natural gas-fired steam turbines at Pueblo Units 5 and 6. On review, the CPUC confirmed Colorado Electric's right to own the replacement capacity for the W.N. Clark power plant and extended the date to refile the resource plan to May 1, 2013.

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

Information regarding our legal proceedings is incorporated herein by reference to the “Legal Proceedings” sub-caption within Item 8, Note 19, “Commitments and Contingencies”, of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

ITEM 4. 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.

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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, 2012, we had 4,517 common shareholders of record and approximately 29,000 beneficial owners, representing all 50 states, the District of Columbia and 8 foreign countries.

We have paid a regular quarterly cash dividend each year since the incorporation of our predecessor company in 1941 and expect to continue paying a regular quarterly dividend for the foreseeable future. At its Jan. 31, 2013 meeting, our Board of Directors declared a quarterly dividend of $0.38 per share, equivalent to an annual dividend of $1.52 per share, marking 2013 as the 43rd 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, 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

Year ended Dec. 31, 2011	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$0.365	$0.365	$0.365	$0.365
Common stock prices				
High	$33.64	$34.85	$32.22	$34.47
Low	$29.76	$28.12	$25.83	$29.10

UNREGISTERED SECURITIES ISSUED

There were no unregistered securities sold during 2012.

ISSUER PURCHASES OF EQUITY SECURITIES

The following table contains information about our acquisitions of equity securities for the three months ended December 31, 2012:

Period	Total Number of Shares Purchased *	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
Oct. 1, 2012 – Oct. 31, 2012	—	N/A	—	—
Nov. 1, 2012 – Nov. 30, 2012	138	$35.38	—	—

Dec. 1, 2012 –Dec. 31, 2012	—	N/A	—	—
Total	138	$35.38	—	—

* Shares were acquired from certain officers and key employees under the share withholding provisions of the Omnibus Incentive Plan for payment of taxes associated with the vesting of restricted stock and the exercise of stock options.

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ITEM 6. SELECTED FINANCIAL DATA

Years Ended Dec. 31, (dollars in thousands, except per share amounts)	2012	(1)	2011	(1)	2010	(1)	2009	(1)	2008	(1)
Total Assets	$3,729,471		$4,127,083		$3,711,509		$3,317,698		$3,379,889	
Property, Plant and Equipment										
Total property, plant and equipment	$3,930,772		$3,724,016		$3,353,509		$2,973,398		$2,703,117	
Accumulated depreciation and depletion	$(1,188,023)		$(934,441)		$(861,775)		$(812,961)		$(681,387)	
Capital Expenditures	$347,980		$431,707		$496,990		$347,819		$1,304,330	(2)
Capitalization										
Current maturities of long-term debt	$103,973		$2,473		$5,181		$35,245		$2,078	
Notes payable	277,000		345,000		249,000		164,500		703,800	
Long-term debt, net of current maturities	938,877		1,280,409		1,186,050		1,015,912		501,252	
Common stock equity	1,232,509		1,209,336		1,100,270		1,084,837		1,050,536	
Total capitalization	$2,552,359		$2,837,218		$2,540,501		$2,300,494		$2,257,666	
Capitalization Ratios										
Short-term debt, including current maturities	14.9 %		12.2 %		10.0 %		8.7 %		31.3 %	
Long-term debt, net of current maturities	36.8 %		45.1 %		46.7 %		44.2 %		22.2 %	
Common stock equity	48.3 %		42.7 %		43.3 %		47.1 %		46.5 %	
Total	100.0 %		100.0 %		100.0 %		100.0 %		100.0 %	
Total Operating Revenues	$1,173,884		$1,272,188		$1,219,691		$1,198,712		$946,480	
Net Income Available for Common Stock										
Utilities	$79,588		$81,860		$74,563		$57,071		$43,904	
Non-regulated Energy	24,725	(4)	866		10,189		1,581	(5)	(42,384)	(6)
Corporate expenses and intersegment eliminations	(15,808)	(3)	(42,361)	(3)	(21,611)	(3)	18,617	(3)	(76,668)	(3)
Income (loss) from continuing operations	88,505		40,365		63,141		77,269		(75,148)	
Income (loss) from discontinued operations, net of tax (7)	(6,977)		9,365		5,544		4,286		180,358	
Net loss attributable to non-controlling interest	—		—		—		—		(130)	

Net income available for common stock	$81,528	$49,730	$68,685	$81,555	$105,080

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SELECTED FINANCIAL DATA continued

Years Ended Dec. 31, (dollars in thousands, except per share amounts)	2012 (1)	2011 (1)	2010 (1)	2009 (1)	2008 (1)
Dividends Paid on Common Stock	$65,262	$59,202	$56,467	$55,151	$53,663
Common Stock Data[8] (in thousands)					
Shares outstanding, average	43,820	39,864	38,916	38,614	38,193
Shares outstanding, average diluted	44,073	40,081	39,091	38,684	38,193
Shares outstanding, end of year	44,206	43,925	39,269	38,969	38,636
Earnings (Loss) Per Share of Common Stock (in dollars) [8]					
Basic earnings (loss) per average share -					
Continuing operations	$2.02	$1.01	$1.62	$2.00	$(1.97)
Discontinued operations	(0.16)	0.24	0.14	0.11	4.72
Total	$1.86	$1.25	$1.76	$2.11	$2.75
Diluted earnings (loss) per average share -					
Continuing operations	$2.01	$1.01	$1.62	$2.00	$(1.95)
Discontinued operations	(0.16)	0.23	0.14	0.11	4.72
Total	$1.85	$1.24	$1.76	$2.11	$2.77
Dividends Declared per Share	$1.48	$1.46	$1.44	$1.42	$1.40
Book Value Per Share, End of Year	$27.84	$27.55	$28.02	$27.84	$27.19
Return on Average Common Stock Equity (year-end)	6.7 %	4.3 %	6.3 %	7.6 %	10.4 %

SELECTED FINANCIAL DATA continued					
Years ended Dec. 31,	2012	2011	2010	2009	2008
Operating Statistics:					
Generating capacity (MW):					
Electric Utilities (owned generation)	859	865	687	630	630
Electric Utilities (purchased capacity)	150	450	440	430	420
Power Generation (owned generation)	309	309	120	120	141
Total generating capacity	1,318	1,624	1,247	1,180	1,191
Electric Utilities:					
Megawatt-hours sold:(1)					
Retail electric	4,598,080	4,590,800	4,532,191	4,403,459	3,532,402
Contracted wholesale	340,036	349,520	468,782	645,297	665,795
Wholesale off-system	1,652,949	1,788,005	1,749,524	1,692,191	1,551,273
Total Megawatt-hours sold	6,591,065	6,728,325	6,750,497	6,740,947	5,749,470
Gas Utilities:(1) (9)					
Gas sold (Dth)	47,358,505	55,764,154	55,265,630	56,671,438	23,053,599
Transport volumes (Dth)	60,480,822	59,216,132	59,879,450	55,104,284	26,805,075
Oil and gas production sold (MMcfe)	12,544	11,762	11,300	12,463	13,534
Oil and gas reserves (MMcfe) (4)	80,683	133,242	131,096	119,304	185,542
Tons of coal sold (thousands of tons) (10)	4,246	5,692	5,931	5,955	6,017
Coal reserves (thousands of tons)	232,265	256,170	261,860	268,000	274,000

(1) All years have been reclassified to include our Energy Marketing segment in Discontinued Operations. 2008 includes electric and gas utilities acquired on July 14, 2008.

(2) Includes $938.4 million for the Aquila acquisition.

(3) 2011, 2010 and 2008 include a $27.3 million, a $9.9 million and a $61.4 million, non-cash after-tax unrealized mark-to-market loss, respectively, related to certain interest rate swaps; while 2012 and 2009 include a $1.2 million and a $36.2 million non-cash after-tax unrealized mark-to-market gain, respectively, related to certain interest rate swaps.

(4) 2012 includes a non-cash after-tax ceiling test impairment loss of $17.3 million offset by an after-tax gain on sale of $18.9 million of our Williston Basin assets (see Notes 12 and 22 of the Notes to the Consolidated Financial Statements of this Annual Report on Form 10-K.)

(5) Includes a $27.8 million non-cash after-tax ceiling test impairment charge to our crude oil and natural gas properties taken in 2009 and a $16.9 million after-tax gain on sale of 23.5 percent ownership interest in Wygen I.

(6) Includes a $59.0 million non-cash after-tax ceiling test impairment charge to our crude oil and natural gas properties taken in 2008.

(7) Discontinued operations include the operations of the Energy Marketing segment in 2012, 2011, 2010, 2009 and 2008, and the assets sold in the IPP Transaction for 2009 and 2008.

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

(9) Excludes Cheyenne Light.

(10) 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 17 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

* On Feb. 29, 2012, we sold Enserco, our Energy Marketing segment, which resulted in this segment being classified as discontinued operations.

Our Utilities Group consists of our Electric and Gas utilities segments. Our Electric Utilities segment generates, transmits and distributes electricity to approximately 202,000 customers in South Dakota, Wyoming, Colorado and Montana and provides natural gas distribution services to approximately 35,000 customers of Cheyenne Light in Wyoming. Our Gas Utilities segment serves approximately 532,000 natural gas customers in Colorado, Iowa, Kansas and Nebraska. Our Non-regulated Energy Group engages in the production of natural gas, crude oil and coal, and the production of electric power through ownership of a portfolio of generating plants, the output energy and capacity of which is sold primarily under mid- and long-term wholesale contracts.

Industry Overview

Recovery from the 2008 global economic crisis remained unpredictable in 2012 because of ongoing sovereign debt problems, mostly centered in the European Union. Slow economic growth continued through 2012 reducing energy demand. Energy commodity prices, which were near historic highs in mid-2008, experienced dramatic declines in early 2009. While crude oil prices recovered notably from 2009 through 2011, natural gas prices have remained low. Domestic crude oil prices continued to be influenced by global factors, including foreign economic conditions (especially in China and Asia), the policies of OPEC and other large foreign oil producers, and political tensions and conflict in many regions.

The proliferation of domestic natural gas shale plays in recent years has provided the domestic market an abundant new supply of natural gas. Combined with lower demand from the economic downturn, this new and abundant supply source has created record volumes of natural gas in storage, and reduced domestic natural gas prices. In fact, the ratio of crude oil to natural gas prices is abnormally high, far in excess of the six to one heating value equivalent ratio. This trend is likely to continue for the foreseeable future given the expected further development of domestic shale gas reserves.

In the United States, electricity generated from coal is approximately 40 percent, down from approximately 50 percent a decade ago. According to the U.S. Energy Information Administration, coal consumption in the United States was estimated to decline approximately 10 percent in 2012 compared to 2011, offset by a growing demand for coal exports. Although coal prices for the Western market continued to experience volatility in 2012 with multiple micro and macro influences impacting prices, coal still remains the leading fuel and the cheapest source of energy for U.S. electricity generation. Powder River Basin (8,800 Btu per pound) spot prices started the year at $10.00/ton, then decreased to $8.25/ton in the summer, but ultimately settled back to $10.00/ton in late 2012.

Like other industries located in the United States, the energy industry is faced with numerous uncertainties, both short and long-term. Many utilities have large capital spending needs over the next few years to replace aging infrastructure, add new assets such as transmission lines and renewable energy resources, and upgrade or replace power generation facilities due to increasingly stringent state and federal emissions regulations. Utility companies generally are less impacted by economic downturns, but the severe recession and prolonged recovery affected demand for energy and the ability of customers to pay their utility bills, particularly in certain parts of the country. Although the recovery in the United States continues to be unpredictable, for credit-worthy companies, equity and debt financings were successfully undertaken over the past few years.

The state utility regulatory climate remained relatively constructive among government, industry and consumer representatives. In the seven-state region encompassing our utility operations, regulators were willing to establish rates based on multi-year considerations, including fuel and other reasonable cost adjustments, justifiable capital expenditures for maintenance and expansion of energy systems, and a response to environmental concerns through demand management and energy efficiency programs. Challenges remain, however, in obtaining satisfactory rate recovery for utility investments due to the general state of the economy and concern by regulators in various states that utility rate increases may cause further harm to local economies. In short, over the past year state regulatory commissions and staffs have become more stringent and conservative related to authorized returns and other regulatory mechanisms related to cost recovery.

Recent federal administrative and legislative actions have set the stage for an emphasis on increased regulation and government oversight of the energy industry. The energy marketplace and the Company continue to respond to the increased oversight and enforcement activity of FERC, and increased environmental and emissions reviews and mandates. The SEC was active issuing several disclosure requirements in 2012 relating to the Dodd-Frank Act which apply to the energy industry. The EPA passed rules in 2011 that will either require expensive upgrades or the closure of many older coal burning power plants. State legislatures also remained active on environmental issues, with a majority of states now having adopted some form of renewable energy standard, including some in which we operate. In addition, several states have passed greenhouse gas emissions legislation, which places limits on the emissions of CO_2 and other GHGs. These known and potential future administrative and legislative actions could have significant macroeconomic consequences, which may impact us, as the associated cost increases may cause a dramatic increase in consumer costs for products and services, including rates for electricity and other energy in the mid- to long-term.

The November 2012 election increased the potential for a new wave of environmental regulations as the President has indicated that the administration would do more to reduce carbon emissions. The passage of the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010, extended through 2012 lower tax rates introduced in 2001 and 2003, reduced the estate tax, extended unemployment benefits, reduced the Social Security portion of payroll taxes for employees, and extended bonus depreciation. A benefit to our investors, the bill extended through 2012 the lower capital gains tax rate introduced by the Jobs and Growth Tax Relief Reconciliation Act of 2003. Additionally, the bill extended the 100 percent bonus depreciation for business property acquired after Sept. 8, 2010 and placed into service prior to Jan. 1, 2012. This provision provided positive tax benefits for the Colorado Electric and Black Hills Colorado IPP generation projects completed in 2011. In early 2013, additional tax legislation was passed that further extended 50 percent bonus depreciation, which will benefit customers related to Cheyenne Prairie. The 2013 legislation also increased the tax rate on dividends and capital gains for many taxpayers and utility investors, but not to the extent industry proponents had feared.

Over the last decade, the corporate structure of many energy companies underwent evaluation and change, in large part due to efforts to create additional shareholder value. Since before the economic crisis, a number of companies contemplated or implemented a realignment of business lines, reflecting a shift in long-term strategies. Some divested certain energy properties to focus on core businesses, such as exiting non-regulated power production or energy marketing, in favor of more stable utility operations. Others engaged in mergers and acquisitions with a goal to improve economies of scale and returns to investors. Private equity investors continued to play a role in the changing composition of energy ownership.

Many industry analysts cite the need for expanded energy capacity and delivery systems. They continue to foresee an increase in capital investment across a wide spectrum of energy companies. Many electric and gas utilities must replace aging plant and equipment, and regulators appear willing to provide acceptable rate treatment for additional utility investment, although the current state of the economy makes rate recovery more challenging in the short run. If warranted based on commodity prices, oil and gas producers will continue to explore for new reserves, particularly natural gas, which will be the primary fuel of choice in light of concern regarding GHG emissions and the need to provide backup generation for renewable energy resources. The growing focus on environmental regulation made it increasingly more difficult to obtain drilling permits, particularly on federal and Native American lands. However, current low natural gas prices prompted some companies to curtail projects in order to conserve cash during a period of low cash flow and constrained capital markets.

Fossil fuel combustion continues to be a contentious domestic and international public policy issue, as many nations, including United States allies, advocate reductions in CO_2 and other emissions. Many states now encourage the energy industry to invest in renewable energy resources, such as wind or solar power, or the use of bio-mass as a fuel. In many instances, renewable energy use is mandated by state regulators. Several years ago, the State of California mandated that future imports of power must come from power plants with emission levels no greater than combined-cycle natural gas-fired plants. Recently proposed EPA regulations on GHG emissions are very similar. Such restrictions may alter transmission flow of power in western states, as a large percentage of current power generation in the western grid comes from coal sources.

The power generation industry continues to make improvements in emissions control, both voluntarily and in response to regulatory mandates. Emissions from new coal-fired plants are now a small fraction of those produced by power plants built a generation ago. With similar technological progress, coal can and likely will remain an important, domestically available, and economical national energy resource that is vital to meet growing energy demand. In that regard, the DOE is beginning to take positive steps toward ensuring the future of coal through research funding for "clean coal" technologies and methods of carbon capture and sequestration.

Energy providers, government authorities and private interests continue to address issues concerning electric transmission, power generation capacity, the use of renewable and other diversified sources of energy, crude oil and natural gas pipelines and storage, and other infrastructure requirements. In the short-term, prevailing economic conditions will reduce industrial and retail energy consumption. Despite public and private efforts to promote conservation and efficiency, however, the demand for energy is expected to increase steadily over the long-term. To meet this demand growth, the industry will need to provide capital, resources and innovation to serve customers cost effectively, and to achieve suitable returns on investment.

We believe that we are well-positioned in this industry setting, and able to proceed with our key business objectives. Along with industry counterparts, we are preparing to address the challenges discussed in this overview, such as new environmental regulations and mandates, renewable portfolio standards, CO_2-related taxes or trading practices, credit market conditions, inflation, or other factors that may affect energy demand and supply. In particular, we are sensitive to additional costs that can negatively affect our customers or our profitability. To that end, we intend to work closely with regulators and industry leaders to assure that cost-conscious proposals and solutions are carefully explored in public policy proceedings.

Business Strategy

We are a customer-focused integrated energy company. Our business is comprised of electric and natural gas utilities, power generation assets, and fuel assets which produce coal, crude oil and natural gas. Our focus on customers - whether they are utility customers or non-regulated energy customers - provides opportunities to expand our businesses 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 businesses 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. Despite challenging conditions in the capital markets over the past few years, we have demonstrated our ability to access the debt and equity markets, resulting in sufficient liquidity and solid cash flows. Consequently, our financial foundation is sound and capable of supporting an expansion of operations in both the near and 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. In our natural gas and electric utilities, we intend to significantly grow our asset base to serve projected customer demand and to comply with environmental mandates in our existing utility service territories through expansion of infrastructure and construction of new rate-based power generation facilities. If the opportunity arises, we will pursue acquisitions of additional utility properties, primarily in the Great Plains and Rocky Mountain regions of the country. By maintaining our high customer service and reliability standards in a cost-efficient manner, our goal is to secure appropriate rate recovery to provide solid economic returns on our utility investments.

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 generation, and potential environmental regulations and legislation that may 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.

Given the amount of electricity currently generated in the United States 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 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, including the possible development of additional power plants at our mine site.

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 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, and 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 the 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, as 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 for consumers, regulators and investors. First, 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. Second, regulators participate in a planning process where long-term investments are designed to match long-term energy demand. Third, investors are assured that a long-term, reasonable, stable rate of return may be earned on their investment. A lower risk profile may also improve credit ratings which, in turn, can benefit both consumers and investors by lowering our cost of capital.

Examples of our progress include the January 2008 completion of Wygen II to serve the customers of Cheyenne Light, the April 2010 completion of Wygen III to serve the customers of Black Hills Power, and the January 2012 completion of a 180 megawatt gas-fired power plant to serve the customers of Colorado Electric. Due to existing legislation in Colorado, we plan to retire Colorado Electric's W.N. Clark plant by Dec. 31, 2013 and EPA regulations covering hazardous air pollutants will necessitate the retirement of several of our other older coal-fired power plants, including Black Hills Power's Osage, Ben French and Neil Simpson I plants in March 2014. We are replacing some of these facilities with Cheyenne Prairie's rate-based natural gas-fired power plants.

For customers in states without renewable or CO_2 mandates, such as South Dakota and Wyoming, we have constructed mine-mouth, state-of-the-art, cost-efficient, coal-fired facilities, such as Wygen II and Wygen III. Given the current environmental regulatory climate, it is unlikely we could secure a permit to construct additional coal-fired generation in the next several years, but we are monitoring developments associated with alternative coal-fired generation technologies, including IGCC and carbon capture and sequestration, though both appear cost prohibitive in the near term. These technologies may become cost effective in the future if regulatory or legislative actions place a sufficiently high price on CO_2 emissions or further technological advancements reduce the costs of those technologies. The location of our coal mine and power plant complex in the Powder River Basin of Wyoming provides key strategic advantages for carbon capture and sequestration projects, such as readily available saline aquifers for the injection and sequestration of CO_2, as well as a potential CO_2 market for use in enhanced oil recovery projects. Additionally, the Wyoming legislature has been proactive in passing legislation to address pore space ownership, injection regulations and other legal issues associated with the underground sequestration of CO_2.

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, however, as a regulated utility we are responsible for providing safe, reasonably priced, reliable sources of energy to our customers. As a result, we have developed 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. Examples of our balanced approach include:

- 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, Wyoming for use at Black Hills Power and Cheyenne Light;

- Colorado and Montana have legislative mandates regarding the use of renewable energy. Therefore, we aggressively pursue cost-effective initiatives with the regulators that will allow us to meet our renewable energy requirements. To the extent practical, we intend 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 CPUC approved a 29 megawatt wind turbine project, completed in the fourth quarter of 2012, in which we are permitted to rate base 50 percent ownership as part of our plan to meet Colorado's Renewable Energy Standard. The Busch Ranch site also has significant expansion potential; 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.

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. The 2005 acquisition of Cheyenne Light and the 2008 Aquila Transaction are examples of such expansion efforts. 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 gas distribution systems, which can be easily integrated into our operations. We purchased several small systems in Kansas and Iowa in the past two years.

We have a platform of systems and processes which are scalable, which should simplify the integration of potential future utility acquisitions. Merger and acquisition activity in the utility industry has increased in the last year. We believe that impacts of the current recession may produce opportunities for healthy utility companies to acquire utility assets and operations of other companies on attractive terms and conditions. We expect to consider such opportunities if we believe they would further our long-term strategy and help 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 and believe we will continue to be a primary provider of electricity to wholesale utility customers. We further believe that these entities will continue to need products, such as capacity, in order to reliably serve their customers. By providing these products under long-term contracts, we are able to 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've established with wholesale power customers have developed into other opportunities. MEAN and MDU, both wholesale power customers, are now also joint owners in two of our power plants, Wygen I and Wygen III, respectively.

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 a combination of 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.

With respect to our current power sale agreements, two of our long-term power contracts provide for the sale of capacity and energy to Cheyenne Light from our Gillette CT and Wygen I plants. The Gillette CT contract expires in 2014. The Wygen I contract expires in 2022, and provides an option for Cheyenne Light to purchase and rate base Black Hills Wyoming's portion of Wygen I.

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 realize the necessity of 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 two 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.

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 Credit 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 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.

We completed several key financings during 2012, including renewing our $500 million Revolving Credit Facility and extending a $150 million term loan.

Prospective Information

We expect to generate long-term growth through the expansion of integrated and diverse energy operations. We recognize that 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 2012, we refinanced our Revolving Credit Facility and term loans on favorable terms. Although dependent on market conditions, we are confident in our ability to obtain additional financing to continue our growth plans. We remain focused on managing our operations cautiously 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

Our Electric Utilities benefited from warm summer weather and an increase in rates resulting from rate cases approved for Colorado Electric and Cheyenne Light. The new rates for Colorado Electric were effective Jan. 1, 2012 upon commercial operation of a 180 megawatt gas-fired generation facility that now serves Colorado Electric customers. New rates for Cheyenne Light were effective on July 1, 2012. The addition of the new generation facility for Colorado Electric to our utility rate base and the successful approval of our rate case had a significant positive impact on our 2012 financial results.

Pursuant to prior approved resource plans, the Electric Utilities engaged in the following regulatory requests for construction activities during 2012:

- The WPSC approved the CPCN for Cheyenne Light and Black Hills Power to construct a new jointly owned 132 megawatt generating facility in Cheyenne, Wyo. with an expected commercial operation date in the fourth quarter of 2014. Cheyenne Light and Black Hills Power also 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, and it will increase gross margin in 2013 and 2014 by approximately $5.5 million and $7.8 million, respectively. A request for a similar rider was made to the SDPUC. The SDPUC approved interim rates for that rider, effective April 1, 2013, which will increase gross margin by approximately $3.6 million and $5.6 million in 2013 and 2014, respectively. Interim rates are subject to refund until final approval is received;

- Colorado Electric completed construction of a 29 megawatt wind project as part of our plan to meet Colorado’s Renewable Energy Standards. It was placed into commercial operation on Oct. 16, 2012 and Colorado Electric owns a 50 percent interest in this wind 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 Busch Ranch wind project; and

- On July 30, 2012, Colorado Electric filed its Electric Resource Plan with the CPUC seeking to develop and own replacement capacity for the retirement of the coal-fired W.N. Clark power plant, consistent with a prior CPUC order that had ordered the plant to be retired per the requirements of the Colorado Clean Air – Clean Jobs Act. The CPUC dismissed the initial filing without prejudice and directed Colorado Electric to refile the resource plan and address alternatives for not just the replacement capacity for its coal-fired W.N. Clark power plant, but also for the retirement of the aging natural gas-fired steam turbines, Pueblo Units #5 and #6. On review, the CPUC confirmed Colorado Electric's right to own the replacement energy for the W.N. Clark power plant and extended the date to refile the resource plan to May 1, 2013.

Gas Utilities

Unseasonably warm winter weather adversely impacted 2012 results at our Gas Utilities. Our Gas Utilities are focused on the continued 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 rural gas infrastructure and the distribution systems. We acquired two small gas systems during 2012 with a total of 327 customers.

Non-regulated Energy Group

Power Generation

Our Power Generation segment was awarded the bid to provide 200 megawatts of power to our Colorado Electric subsidiary through a 20-year PPA. Construction for a 200 megawatt combined cycle natural gas-fired power generation facility in Colorado was completed in December 2011 and this facility commenced commercial operation on Jan. 1, 2012. We plan to continue evaluating opportunities to bid on the construction of generation resources, both new and existing, for 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 4.5 million tons for 2013, which is consistent with 2012. 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 was such that we were not recovering 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 should reduce mining costs for the next several years.

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 our off-site sales have been to consumers within a close proximity to our mine. We have recently extended two smaller volume off-site sales contracts served by truck. There are some limitations in regards to transporting our lower-heat content coal; however, we continue to pursue new opportunities to market our coal.

Oil and Gas

During much of 2012, BHEP's mission was to identify future investment opportunities while conserving capital and strictly controlling costs. In September 2012, we sold approximately 85 percent of our Bakken and Three Forks shale assets in the Williston Basin in North Dakota representing 73 gross wells and approximately 28,000 net leasehold acres for approximately $227.9 million. The sale reduced the full-cost pool by $198 million which will reduce our depreciation, depletion and amortization rate in the future. We will continue our efforts into 2013 to develop attractive oil and gas investment opportunities.

Corporate

On Feb. 1, 2012, we entered into a new five year $500 million Revolving Credit Facility at favorable terms, and on Oct. 31, 2012, we redeemed our $225 million senior unsecured 6.5 percent bonds early with the proceeds from the sale of the oil and gas assets. Repayment of this debt will significantly lower our interest expense in 2013.

As of Dec. 31, 2012, we had interest rate swaps with a notional amount of $250 million, which do not currently qualify for "hedge accounting" treatment provided by accounting standards for derivatives and hedges. Accordingly, all mark-to-market adjustments on these swaps are recorded through the income statement. As of Dec. 31, 2012, the mark-to-market value of these swaps was a liability of $88.1 million. In 2012, we recorded an unrealized mark-to-market after-tax gain of $1.2 million on these swaps. Fluctuations in interest rates create volatility in the fair value of these swaps which will likely have an impact on our 2013 earnings as we record the associated unrealized mark-to-market gains or losses within our income statement.

Results of Operations

Executive Summary and Overview

	For the Years Ended Dec. 31,				
	2012	Variance	2011	Variance	2010
	(in thousands)				
Revenue					
Utilities	$1,081,047	$(87,868)	$1,168,915	$48,194	$1,120,721
Non-regulated Energy	216,239	37,867	178,372	16,017	162,355
Inter-company eliminations	(123,402)	(48,303)	(75,099)	(11,714)	(63,385)
	$1,173,884	$(98,304)	$1,272,188	$52,497	$1,219,691
Income (loss) from continuing operations					
Electric Utilities	$51,598	$3,907	$47,691	$239	$47,452
Gas Utilities	27,990	(6,179)	34,169	7,058	27,111
Utilities	79,588	(2,272)	81,860	7,297	74,563
Power Generation	21,328	18,317	3,011	860	2,151
Coal Mining	5,626	6,050	(424)	(8,105)	7,681
Oil and Gas [(a)]	(2,229)	(508)	(1,721)	(2,078)	357
Non-regulated Energy	24,725	23,859	866	(9,323)	10,189
Corporate and Eliminations [(b)(c)]	(15,808)	26,553	(42,361)	(20,750)	(21,611)
Income from continuing operations	88,505	48,140	40,365	(22,776)	63,141
Income (loss) from discontinued operations, net of tax [(d)]	(6,977)	(16,342)	9,365	3,821	5,544
Net income (loss)	$81,528	$31,798	$49,730	$(18,955)	$68,685

(a) Income (loss) from continuing operations in 2012 includes a $17.3 million non-cash after-tax ceiling test impairment loss and an $18.9 million after-tax gain on sale of our Williston Basin assets. See Notes 12 and 22 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

(b) 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 and accordingly have been presented within Corporate of $0.6 million and $2.2 million for 2012 and 2011, respectively. See Note 23 of the Consolidated Financial Statements in this Annual Report on Form 10-K.

(c) Includes a $1.2 million non-cash after-tax mark-to-market gain on certain interest rate swaps in 2012 and a $27.3 million non-cash after-tax mark-to-market loss in 2011 on those same certain interest rate swaps.

(d) Income (loss) from discontinued operations, net of tax includes the activities of Enserco, our Energy Marketing segment. See Note 23 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.

2012 Compared to 2011

Income from continuing operations was $88.5 million, or $2.01 per share, in 2012 compared to $40.4 million, or $1.01 per share, in 2011. The 2012 Income from continuing operations includes an $18.9 million after-tax gain on sale related to the Williston Basin asset sale, a $17.3 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 $27.3 million non-cash after-tax mark-to-market loss on certain interest rate swaps.

Net income was $81.5 million, or $1.85 per share, in 2012 compared to $49.7 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. 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 and Black Hills Power. Cheyenne Light will own 40 megawatts and Black Hills Power will own 55 megawatts of the combined-cycle unit. We have ordered all major equipment for the project and commencement of construction is expected in spring 2013. Commercial operation is expected in the fourth quarter of 2014. Project costs for plant construction and associated transmission are estimated at $222 million, with up to $15 million of construction financing, for a total of $237 million.

- 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, and it will increase gross margin in 2013 and 2014 by approximately $5.5 million and $7.8 million, respectively. 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. We expect a final ruling by the SDPUC on the construction financing rider before the end of the third quarter.

- 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 certain older coal-fired and natural gas-fired facilities. In addition, the companies identified retirement dates for the older coal-fired power plants because of state and federal environmental regulations and cost to retrofit. The affected plants are listed in the table below with their operations suspension date (if applicable) and their ultimate retirement date (if identified).

Plant	Company	Megawatts	Type of Plant	Date Suspended	Planned 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	to be determined	71
Pueblo Unit #6	Colorado Electric	20.0	Gas	Dec. 31, 2012	to be determined	63
	Total MW	152.3				

- On July 30, 2012, Colorado Electric filed its Electric Resource Plan with the CPUC seeking to develop and own replacement capacity for the retirement of the coal-fired W.N. Clark power plant, which must be retired pursuant to the Colorado Clean Air – Clean Jobs Act. The CPUC dismissed the initial filing and directed Colorado Electric to refile its Electric Resource Plan by May 1, 2013 in order to address alternatives for the replacement capacity of W.N. Clark power plant, as well as the retirement of Pueblo #5 and Pueblo #6 and directed Colorado Electric to request a CPCN for any replacement capacity that Colorado Electric seeks to develop and own.

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 $227.9 million. We recognized a gain of $29.1 million on the sale. The portion of the sale amount not recognized as gain reduced the full-cost pool and should significantly decrease the future depreciation, depletion and amortization rate.

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Coal Mining commenced operations under its revised mine plan. Mining operations moved in August 2012, to an area with lower overburden ratios, which should reduce mining costs for the next several years.

- In the second quarter of 2012, our Oil and Gas segment recorded a $26.9 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 $42.0 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 Dec. 31, 2012 from the transaction were approximately $165.0 million, subject to final post-closing adjustments.

2011 Compared to 2010

Income from continuing operations was $40.4 million, or $1.01 per share, in 2011 compared to $63.1 million, or $1.62 per share, in 2010. The 2011 Income from continuing operations includes a $27.3 million after-tax non-cash mark-to-market loss on certain interest rate swaps. The 2010 Income from continuing operations includes a gain on sale of $5.8 million after-tax of a 23 percent ownership interest in the Wygen III plant and assets sold by Nebraska Gas after the annexation of a service area; and a $9.9 million after-tax non-cash mark-to-market loss on certain interest rate swaps.

Net income was $49.7 million, or $1.24 per share, in 2011 compared to $68.7 million, or $1.76 per share, in 2010. Enserco, our Energy Marketing segment, has been reclassified and is included in Income from discontinued operations in 2011 and 2010.

Highlights of our business groups are as follows:

Utilities Group

Our Electric Utilities were positively impacted by approved rate cases and an increase in off-system sales margins. Our Gas Utilities recorded increased margins due to the impact of rate increases. Additional highlights of the Utilities Group include the following:

- Revenues in 2011 were positively impacted by a full year of rate increases that became effective at various dates in 2010 (dollars in millions).

Utility	State	Effective Date	Annual Revenue Increase	
Black Hills Power	SD	4/2010	$	15.2

Black Hills Power	WY	6/2010		3.1
Colorado Electric	CO	8/2010		17.9
Nebraska Gas	NE	3/2010		8.3
Iowa Gas	IA	6/2010		3.4
			$	47.9

- A 180 megawatt gas-fired generation plant constructed to serve Colorado Electric customers started providing energy on Jan. 1, 2012.

- The Wygen III generating facility commenced commercial operations on April 1, 2010. In July 2010, Black Hills Power sold a 23 percent ownership interest in the Wygen III power generation facility to the City of Gillette for $62.0 million. A gain of $6.2 million was recognized on the sale.

- On Oct. 1, 2010, Black Hills Power suspended the operations of its 62 year old, 34.5 megawatt coal-fired Osage Power Plant located in Osage, Wyo. We now have more economical power supply alternatives available to provide for present customer energy demands. The plant's operating permits have been retained so that full operations can be restored if needed until its' planned retirement in March 2014.

- Our Electric Utilities reached agreement with the DOE for smart grid funding through matching grants totaling $20.7 million, made available through the American Recovery and Reinvestment Act of 2009. We have completed 100 percent of the installations related to these meters.

- Due to the annexation of an outlying suburb by the City of Omaha, Neb., we sold assets serving approximately 3,000 customers to Metropolitan Utilities District on March 2, 2010. We received $6.1 million in cash and recognized a $2.7 million gain on the sale in 2010.

- In December 2010, Colorado Electric received a final order from the CPUC regarding its plan to comply with the Colorado Clean Air, Clean Jobs Act. The order approved the retirement of the utility's 40 megawatt W.N. Clark coal-fired generation facility and granted a presumption of need for replacement of the plant.

Non-Regulated Energy Group

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

- A 200 megawatt gas-fired generation plant constructed for Black Hills Colorado IPP to serve a 20-year PPA with Colorado Electric started providing energy on Jan. 1, 2012.

Corporate

Activities of Corporate include the following:

- We recognized a non-cash unrealized mark-to-market loss related to certain interest rate swaps of $42.0 million in 2011 compared to a $15.2 million unrealized loss on these swaps for the same period in 2010.

- In April 2010, we entered into a new three-year $500 million Revolving Credit Facility. The Revolving Credit Facility was used to fund working capital needs and other corporate purposes.

- In July 2010, we completed a public offering of $200 million aggregate principal amount of senior unsecured notes due July 15, 2020. The notes were priced at par and carry an interest rate of 5.875 percent.

- In November 2010, we entered into an equity forward offering for 4,000,000 shares. In December 2010, the underwriters exercised their over-allotment option and purchased 413,519 additional shares. We settled the equity forward instruments in November 2011.

- In December 2010, we entered into a $100 million unsecured one-year term loan. The cost of borrowings under the loan is based on a spread of 1.375 percent over LIBOR.

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In 2010, we recorded a $2.4 million reduction in tax expense reflecting a re-measurement of a tax position in accordance with accounting for uncertain tax positions. Approximately $2.0 million of this benefit was recorded in the Corporate segment. The re-measurement was prompted by a settlement agreement that was reached with the IRS Appeals Division primarily regarding tax depreciation method changes.

Operating Results

A discussion of operating results from our business segments follows.

Utilities Group

Electric Utilities

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

	2012	Variance	2011	Variance	2010
Revenue - electric	$595,542	$18,029	$577,513	$45,090	$532,423
Revenue - Cheyenne Light gas	31,424	(5,394)	36,818	(773)	37,591
Total revenue	626,966	12,635	614,331	44,317	570,014
Fuel and purchased power - electric	257,042	(31,312)	288,354	18,607	269,747
Purchased gas - Cheyenne Light	16,432	(5,566)	21,998	(1,066)	23,064
Total fuel and purchased power	273,474	(36,878)	310,352	17,541	292,811
Gross margin - electric	338,500	49,341	289,159	26,483	262,676
Gross margin - Cheyenne Light gas	14,992	172	14,820	293	14,527
Total gross margin	353,492	49,513	303,979	26,776	277,203
Operations and maintenance	146,527	3,712	142,815	5,942	136,873
Gain on sale of operating asset	—	768	(768)	5,470	(6,238)
Depreciation and amortization	75,244	22,769	52,475	5,199	47,276
Total operating expenses	221,771	27,249	194,522	16,611	177,911
Operating income	131,721	22,264	109,457	10,165	99,292
Interest expense, net	(51,041)	(12,065)	(38,976)	(1,933)	(37,043)
Other income, net	1,182	701	481	(2,734)	3,215
Income tax expense	(30,264)	(6,993)	(23,271)	(5,259)	(18,012)
Income (loss) from continuing operations	$51,598	$3,907	$47,691	$239	$47,452

	2012	2011	2010
Regulated power plant fleet availability:			
Coal-fired plants [(a)]	90.8%	91.3%	93.9%
Other plants	96.9%	96.4%	96.2%
Total availability	93.9%	93.1%	94.8%

(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.

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 a lower 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.

2011 Compared to 2010

Gross margin increased primarily due to a $17.1 million increase related to rate adjustments that include a return on significant capital investments, $1.3 million increase from the impact of a new Environmental Improvement Cost Recovery rider at Black Hills Power that went into effect on June 1, 2011, $3.1 million increase in retail megawatt-hours sold, $6.9 million increase for TCAs for retail and wholesale customers, and $0.3 million increase in off-system sales impacted by recognition of $0.7 million of deferred margins upon settlement of Colorado Electric’s power marketing sharing mechanism with the CPUC.

Operations and maintenance increased primarily due to higher allocation of corporate costs driven by an increased asset base in the Electric Utilities; additional costs associated with Wygen III, which commenced commercial operation on April 1, 2010, and approximately $1.1 million of deferred power marketing costs that were recognized in 2011 upon settlement of an off-system sales sharing mechanism with the CPUC, partially offset by suspension of the Osage plant.

Gain on sale of operating assets in 2011 relates to the sale of assets to a related party. This gain was eliminated from the consolidated results of the Company. The gain on sale of operating assets in 2010 represents the sale of a 23 percent ownership interest in the Wygen III generating facility to the City of Gillette, Wyo.

Depreciation and amortization increased primarily due to a higher asset base including additional depreciation associated with Wygen III, which began commercial operation on April 1, 2010.

Interest expense, net increased due to higher borrowings related to recent capital projects, partially offset by increased AFUDC-borrowed and interest income. AFUDC-borrowed increased $5.1 million at Colorado Electric due to construction of the Pueblo Airport Generating Station, offset by a decrease in AFUDC-borrowed at Black Hills Power of $1.8 million due to the commencement of commercial operations of Wygen III.

Other income, net decreased primarily due to lower AFUDC-equity of $2.0 million, which decreased upon the placement of Wygen III into commercial operations on April 1, 2010.

Income tax expense: The effective tax rate increase in 2011 compared to 2010 reflects a $2.2 million benefit for a repairs deduction taken for tax purposes and the flow-through treatment of such tax benefit resulting from a rate case settlement in 2010.

Gas Utilities

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

	2012	Variance	2011	Variance	2010
Natural gas - regulated	$425,268	$(101,704)	$526,972	$6,281	$520,691
Other - non-regulated	28,813	1,201	27,612	(2,404)	30,016
Total revenue	454,081	(100,503)	554,584	3,877	550,707
Natural gas - regulated	231,262	(85,995)	317,257	711	316,546
Other - non-regulated	14,087	(617)	14,704	(2,467)	17,171
Total cost of sales	245,349	(86,612)	331,961	(1,756)	333,717
Natural gas - regulated	194,006	(15,709)	209,715	5,570	204,145
Other non-regulated	14,726	1,818	12,908	63	12,845
Total gross margin	208,732	(13,891)	222,623	5,633	216,990
Operations and maintenance	117,390	(4,590)	121,980	(3,467)	125,447
Gain on sale of operating assets	—	—	—	2,683	(2,683)
Depreciation and amortization	25,163	856	24,307	(951)	25,258
Total operating expenses	142,553	(3,734)	146,287	(1,735)	148,022
Operating income	66,179	(10,157)	76,336	7,368	68,968
Interest expense, net	(23,981)	1,995	(25,976)	1,479	(27,455)
Other expense (income), net	105	(112)	217	170	47
Income tax expense	(14,313)	2,095	(16,408)	(1,959)	(14,449)
Income from continuing operations	$27,990	$(6,179)	$34,169	$7,058	$27,111

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 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.

2011 Compared to 2010

Gross margin increased primarily due to an increase in rates from rate case settlements.

Operations and maintenance decreased primarily due to decreases in employee benefit costs, workers compensation insurance, lower corporate allocations and litigation-related expenses.

Gain on sale of operating assets was recognized in 2010 on assets sold to the City of Omaha, Neb. following annexation of a portion of our service territory by the city.

Depreciation and amortization decreased primarily due to certain assets that became fully depreciated during 2010, partially offset by capital expenditures during 2011.

Interest expense, net decreased primarily due to lower inter-company debt and allocation of debt service within the assigned capital structure.

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

Income tax expense: The effective tax rate for 2011 decreased compared to the same period in the prior year primarily as a result of a true-up adjustment related to the 2010 tax filing 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):

	2012	Variance	2011	Variance	2010
Revenue	$79,389	$47,717	$31,672	$1,323	$30,349
Operations and maintenance	29,991	13,453	16,538	328	16,210
Depreciation and amortization	4,599	400	4,199	(267)	4,466
Total operating expenses	34,590	13,853	20,737	61	20,676
Operating income	44,799	33,864	10,935	1,262	9,673
Interest expense, net	(14,757)	(7,383)	(7,374)	736	(8,110)
Other income (expense), net	7	(1,087)	1,094	240	854
Income tax expense	(8,721)	(7,077)	(1,644)	(1,378)	(266)
Income from continuing operations	$21,328	$18,317	$3,011	$860	$2,151

	2012	2011	2010
Contracted fleet plant availability:			
Gas-fired plants	99.4%	98.4%	99.9%
Coal-fired plants	99.6%	100.0%	98.5%
Total	99.4%	99.0%	99.1%

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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.

2011 Compared to 2010

Revenue increased primarily due to higher sales from Wygen I, which incurred a forced outage and major overhaul in the prior year.

Operations and maintenance increased primarily due to higher costs associated with the Black Hills Colorado IPP as employees prepared for operations of the facilities. This was partially offset by lower operating costs associated with Wygen I which incurred a forced outage and major overhaul in the prior year.

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

Interest expense, net decreased primarily due to capitalized interest related to the generation construction at Black Hills Colorado IPP and increased inter-company interest income at Black Hills Wyoming.

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

Income tax expense: The effective tax rate for 2011 increased compared to the same period in the prior year primarily due to a true-up for research and development credits in 2010.

Coal Mining

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

	2012	Variance	2011	Variance	2010
Revenue	$57,778	$(9,114)	$66,892	$9,050	$57,842
Operations and maintenance	42,553	(14,064)	56,617	22,589	34,028
Depreciation, depletion and amortization	13,060	(5,610)	18,670	(413)	19,083
Total operating expenses	55,613	(19,674)	75,287	22,176	53,111
Operating income (loss)	2,165	10,560	(8,395)	(13,126)	4,731
Interest income, net	930	(2,958)	3,888	708	3,180
Other income, net	2,616	424	2,192	43	2,149
Income tax benefit (expense)	(85)	(1,976)	1,891	4,270	(2,379)
Income (loss) from continuing operations	$5,626	$6,050	$(424)	$(8,105)	$7,681

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

	2012	2011	2010
Tons of coal sold	4,246 [(a)]	5,692	5,931
Cubic yards of overburden moved	8,329	14,735	15,679
Coal reserves at year-end	232,265	256,170	261,860

(a) Decrease in tons of coal sold is due to the Dec.31, 2011 expiration of an agreement with PacifiCorp.

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 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.

2011 Compared to 2010

Revenue increased primarily due to a 21 percent increase in average price per ton partially offset by a 4 percent decrease in volumes sold as a result of overhauls and unplanned outages at the PacifiCorp operated Wyodak plant. The higher average sales price reflects the impact of price escalators and adjustments in certain of our sales contracts. In 2011, approximately 40 percent of our coal production was sold under contracts that include price adjustments based on actual mining costs. Most of our remaining production is sold under contracts where the sales price may escalate based on published indices. These escalators have not kept up with actual mining cost increases, reducing coal mine operating income and negatively impacting 2011 results. One of these contracts, representing 29 percent of the tons sold during 2011, was terminated at Dec. 31, 2011.

Operations and maintenance increased reflecting longer haul distances and higher overburden stripping costs in the current phase of our mining. Additionally, we experienced higher costs associated with drilling and blasting, equipment maintenance, clay parting removal, fuel, staffing levels for our train load-out facility and weather conditions. As noted above, a portion of our production is sold under contracts that have price escalators based on published indices. These escalators have not kept up with actual mining cost increases, reducing coal mine operating income and negatively impacting 2011 results. One of these contracts, representing 29 percent of the tons sold during 2011, was terminated at Dec. 31, 2011. Previous periods also include the capitalization of certain costs associated with mine infrastructure, including our in-pit conveyor system used to transport coal to mine-mouth generation facilities.

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

Interest income, net increased primarily due to increased lending to affiliates.

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

Income taxes: The effective tax rate decreased primarily due to an increased tax benefit from percentage depletion and a research and development credit.

Oil and Gas

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

	2012	Variance	2011	Variance	2010
Revenue	$79,072	$(736)	$79,808	$5,644	$74,164
Operations and maintenance	43,267	1,887	41,380	2,081	39,299
Gain on sale of assets	(29,129)	(29,129)	—	—	—
Depreciation, depletion and amortization	38,494	2,804	35,690	5,407	30,283
Impairment of long-lived assets	26,868	26,868	—	—	—
Total operating expenses	79,500	2,430	77,070	7,488	69,582
Operating income (loss)	(428)	(3,166)	2,738	(1,844)	4,582
Interest expense, net	(3,935)	1,959	(5,894)	(522)	(5,372)
Other income (expense), net	207	423	(216)	(938)	722
Income tax benefit (expense)	1,927	276	1,651	1,226	425

Income (loss) from continuing operations	$(2,229	) $(508	) $(1,721	) $(2,078	) $357

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

Crude Oil and Natural Gas Production	2012	2011	2010
Bbls of oil sold	559,971	451,823	375,646
Mcf of natural gas sold	8,686,191	8,526,420	8,483,981
Gallons of NGL sold	3,485,514	3,674,814	3,937,584
Mcf equivalent sales	12,543,948	11,762,331	11,300,369

Average Price Received [(a)]	2012	2011	2010
Gas/Mcf	$3.33	$4.29	$4.85
Oil/Bbl	$83.27	$79.74	$75.59
NGL/gallon	$0.77	$0.96	$0.74

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(a) Net of hedge settlement gains/losses

	2012	2011	2010
Depletion expense/Mcfe*	$2.87	$2.76	$2.36

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* The average depletion rate per Mcfe is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented. The increased depletion rate in 2012 is primarily driven by the high cost of wells associated with our drilling activities in the Bakken shale formation. The depletion rate for the nine months prior to the Williston Basin sale was $3.07 per Mcfe and $1.44 per Mcfe for the remaining three months of 2012 subsequent to the sale. The reduction in the full cost pool due to the sale of our Williston Basin assets should significantly decrease the depletion per Mcfe rate in 2013. See Note 22 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:

	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
Total	$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
Total	$1.07	$0.23	$0.70	$2.00

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	2010			
	LOE	Gathering Compression and Processing	Production Taxes	Total
San Juan	$1.30	$0.34	$0.54	$2.18
Piceance	0.68	0.64	(0.09)	1.23
Powder River	1.20	—	1.02	2.22
Williston	0.92	—	1.03	1.95
All other properties	0.92	—	0.25	1.17
Total	$1.13	$0.22	$0.55	$1.90

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:

	2012	2011	2010
Bbls of oil (in thousands)	4,116	6,223	5,940
MMcf of natural gas	55,985	95,904	95,456
Total MMcfe	80,683	133,242	131,096

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 2012 production of approximately 12.0 Bcfe, additions from extensions, discoveries and acquisitions of 5.6 Bcfe and negative revisions to previous estimates of 4.0 Bcfe, primarily due to reserve aging.

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

	2012		2011		2010	
	Oil	Gas	Oil	Gas	Oil	Gas
NYMEX prices	$94.71	$2.76	$96.19	$4.12	$79.43	$4.38
Well-head reserve prices	$85.31	$2.24	$88.49	$3.59	$70.82	$3.45

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 should significantly decrease the future 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.

2011 Compared to 2010

Revenue increased primarily due to a 5 percent increase in the annual average hedged price received for crude oil and a 20 percent increase in crude oil production, partially offset by a 12 percent decrease in the annual average hedged price received for natural gas. The increase in crude oil production is primarily due to production from new wells in our ongoing Bakken drilling program. Natural gas production increased slightly as production from new wells has more than offset natural production declines in existing producing properties, which followed reduced capital deployment during 2010 and 2009.

Operations and maintenance increased primarily as a result of increased production taxes from higher revenue.

Depreciation, depletion and amortization increased primarily due to a higher depletion rate per Mcfe. The increasing depletion rate is primarily driven by the high cost of wells associated with our oil drilling activities in the Bakken shale formation.

Interest expense, net increased primarily due to increased debt used to finance additional capital expenditures and higher interest rates.

Other income, net decreased primarily due to lower earnings from our equity investments.

Income tax (benefit) expense: The effective tax rate in both 2011 and 2010 includes a tax benefit related to percentage depletion. The effect of such benefit on the effective tax rate was more pronounced in 2010. Additionally, 2010 includes a $0.4 million re-measurement of a previously recorded uncertain tax position prompted by a settlement agreement with the IRS Appeals Division.

Corporate

Corporate results represent 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.

2012 Compared to 2011

Corporate results for 2012 included costs related to early retirement of debt and refinancing of debt in the amount of $7.1 million 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 $42.0 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.

2011 Compared to 2010

Corporate results for 2011 included a $42.0 million unrealized mark-to-market loss in 2011 related to certain interest rate swaps compared to a $15.2 million unrealized mark-to-market loss in 2010 on those same interest rate swaps. Additionally, Corporate results included $3.4 million of costs originally allocated to our Energy Marketing segment in 2011 which consistent with accounting for discontinued operations could not be included in discontinued operations compared to $3.5 million in 2010.

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 on Dec. 31, 2012 were approximately $165.0 million, subject to final post-closing adjustments. The proceeds represent $107.5 million received from the buyer and $57.5 million cash retained from Enserco before closing.

Income (loss) from discontinued operations was $(7.0) million and $9.4 million for the twelve months ended Dec. 31, 2012 and 2011, respectively. Results for 2012 include an after-tax loss on sale of $2.5 million including transaction related costs, net of tax benefit of $2.5 million.

Pursuant to the provisions of the Stock Purchase Agreement, disputes regarding post-closing purchase price adjustments are subject to arbitration before a nationally-recognized accounting firm and all other disputes are subject to the indemnification procedures in the agreement. The buyer originally demanded an amount totaling $7.2 million, characterizing all claims in such demand as purchase price adjustments. We contested certain claims in the buyer's demand, including whether certain claims were properly characterized as purchase price adjustments, but reached a partial settlement and paid the buyer the sum of $1.4 million. The parties were unable to reach a negotiated agreement regarding the balance of the claims.

In December 2012, we agreed to arbitrate the claims that we believe are properly characterized as purchase price adjustments, but objected to the arbitration of the claims that we believe are not properly characterized as purchase price adjustments. After joint discussions of the parties with the arbitrator, in January 2013 the arbitrator advised the parties that it would not arbitrate the claims to which we objected. On Feb. 7, 2013, the buyer filed a petition in the United States District Court for the District of Colorado applying for an order compelling arbitration on all of the disputed claims. We will respond to this litigation, requesting the court to deny the buyer's application. The filing of this petition does not alter our characterization or evaluation of the original claim.

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 annual goodwill impairment test as of November 30 each year or upon the occurrence of events or changes in circumstances that indicate that the asset might be impaired. Accounting standards for testing goodwill for impairment require a two-step process be performed to analyze whether or not goodwill has been impaired. Goodwill is tested for impairment at the reporting unit level. Our reporting units have been determined to be at the operating segment 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 $353.4 million in goodwill as of Dec. 31, 2012. The results of our Nov. 30, 2012 annual impairment test indicated that our goodwill was not impaired, as the estimated fair value of all reporting units exceeded their carrying value.

Although an impairment did not exist as of Nov. 30, 2012, we determined that one reporting unit, Colorado Electric with goodwill of $245.6 million, had an estimated fair value that exceeded its carrying value by only 15 percent, which we do not consider a substantial excess. The result of our valuation analysis estimates Colorado Electric's fair value at $825.6 million, compared to a carrying value of $717.9 million as of Nov. 30, 2012. The result of the income approach was sensitive to the 2.0 percent long-term cash flow growth rate applicable to periods beyond our internal five-year business plan financial forecast and the 5.66 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 $33 million or 5 percent as of Nov. 30, 2012.

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 $17.3 million after-tax. Under the SEC-defined product prices at Dec. 31, 2012, no additional write-down was required. Reserves in 2012 and 2011 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 was significant as defined by Rule 4-10 and, accordingly, an $18.9 million after-tax gain on sale was recorded. Total net cash proceeds from the sale were approximately $227.9 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 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.
Any change in the gain recorded would impact the amount of adjustment to our capitalized costs therefore impacting future depletion expense recorded within our 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 3, “Risk Management Activities” and Note 4, “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 (see below), 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.

We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations. We have interest rate swaps with a notional amount of $250 million that are not designated as hedge instruments. Accordingly, mark-to-market changes in value on the swaps are recorded within the income statement. A one basis point move in the interest rate curves over the term of the swaps would have a pre-tax impact of approximately $0.4 million. These swaps have remaining terms of 6 and 16 years and have early termination dates ranging from Dec. 15, 2013 to Dec. 31, 2013, respectively.

Counterparty Credit Risk and Allowance for Doubtful Accounts

As of Dec. 31, 2012, our credit exposure included a $7.6 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. We seek to minimize counterparty credit risk through an evaluation of their financial condition and credit ratings and by imposing collateral requirements under certain circumstances, including the use of master netting agreements.

We continuously monitor collections and payments from our customers and establish an allowance for doubtful accounts based upon our historical experience and any specific customer collection issue that we have identified. The allowances provided are estimated and may be impacted by economic, market and regulatory conditions, which could have an effect on future allowance requirements and significantly impact future results of operations. While most credit losses have historically been within our expectations and established provisions, we can provide no assurance that our actual credit losses will be consistent with our estimates.

Pension and Other Postretirement Benefits

As described in Note 18 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. 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 2013 for our non-contributory funded pension plan is expected to be $15.4 million compared to $13.9 million in 2012. The estimated discount rate used to determine annual benefit cost accruals will be 4.30 percent in 2013; the discount rate used in 2012 was 4.65 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 December 31, 2012 Accumulated Postretirement Benefit Obligation	Impact on 2012 Service and Interest Cost
Increase 1%	$ 2,082	$ 127
Decrease 1%	$ (1,771)	$ (107)

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 this 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, we do not expect that the recently enacted American Taxpayer Relief Act of 2012 will have a material impact on the amounts provided for income taxes including our ability to realize deferred tax assets. Since the date of enactment was Jan. 2, 2013, the ATRA could not be considered when determining deferred tax liabilities and assets as of Dec. 31, 2012, which resulted in the reclassification of a sizable amount of Federal and state deferred tax assets related to net operating loss carryforwards from non-current to current. However, certain provisions of the ATRA, primarily the extension of 50 percent bonus depreciation, are currently expected to result in minimal utilization of such carryforwards in 2013. 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	2012	2011
Cash and cash equivalents	$15,462	$21,628
Restricted cash and equivalents	$7,916	$9,254
Short-term debt, including current maturities of long-term debt	$380,973	$347,473
Long-term debt	$938,877	$1,280,409
Stockholders' equity	$1,232,509	$1,209,336
Ratios		
Long-term debt ratio	43.2%	51.4%
Total debt ratio	51.7%	57.4%

The proceeds from the sale of Enserco and the sale of a majority of our Williston Basin assets were used to pay down debt, improving our credit profile.

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, 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 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 target to hedge approximately 70 percent to 100 percent of our existing natural gas and crude oil production using options, futures and basis swaps for the next two years. 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, 2012, 96.5 percent of our interest rate exposure has been mitigated through either fixed or hedged interest rates.

We have interest rate swaps with a notional amount of $250 million that are not designated as hedge instruments. Accordingly, mark-to-market changes in value on these swaps are recorded within the income statements. We recorded a $1.9 million non-cash pre-tax unrealized mark-to-market gain and $42.0 million non-cash pre-tax unrealized mark-to-market loss on these swaps for the years ended Dec. 31, 2012 and Dec. 31, 2011, respectively. The mark-to-market value on these swaps was a liability of $88.1 million, net of cash collateral, at Dec. 31, 2012. Subsequent mark-to-market adjustments could have a significant impact on our results of operations. A one basis point move in the interest rate curve over the term of the swaps would have a pre-tax impact of approximately $0.3 million. These swaps are for terms of 6 and 16 years and have early termination dates ranging from Dec. 15, 2013 to Dec. 31, 2013, respectively. We anticipate extending these agreements upon their early termination dates and have continued to maintain these swaps in anticipation of our upcoming financing needs. Alternatively, we may choose to cash settle these swaps at fair value prior to the early termination dates, or unless these dates are extended, we will cash settle these swaps for an amount equal to their fair value on the termination dates.

In addition, we have $150 million notional amount floating-to-fixed interest rate swaps with a maximum remaining term of 4 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 $24 million at Dec. 31, 2012.

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

The Tax Relief Unemployment Insurance Reauthorization and Job Creation Act of 2010, enacted into law on Dec. 17, 2010, included provisions allowing for the acceleration of depreciation of certain property for tax purposes. These provisions resulted in approximately $320 million of tax benefits for BHC as indicated in the table below. The tax benefits contributed to the generation of a tax loss carryforward that we believe will defer payment of cash taxes until approximately 2016.

(in millions)	2012	2011	2010
Tax benefit	$56	$218	$46

The ATRA, enacted into law on Jan. 2, 2013, extended 50 percent bonus depreciation generally to qualifying property placed in service during 2013. It is anticipated that the extension of bonus depreciation by the ATRA will result in approximately $65 million of additional tax benefits to BHC. The additional depreciation deductions will serve to reduce taxable income and extend the tax loss carryforwards as indicated above from being fully utilized in 2016 to being fully utilized in 2017 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 REQUIRMENTS

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.

Restricted Cash

Although we have the ability to access cash when necessary, some of our subsidiaries have contractual agreements with covenants that restrict the use of cash. As provisions under these agreements are met, cash is no longer restricted and becomes available for its intended purposes. Our restricted cash positions as of Dec. 31, 2012 totaled $7.9 million.

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	2012	2011
Natural Gas Futures and Basis Swaps Pursuant to Utility Commission Approved Hedging Programs	$ 12,930	$ 19,416
Oil and Gas Derivatives	3,193	—
Interest Rate Swaps Derivatives Not Designated as Hedges	5,960	—
Total Cash Collateral Positions	$ 22,083	$ 19,416

CASH FLOW ACTIVITIES

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

	2012	2011	2010
Cash provided by (used in)			
Operating activities	$ 316,971	$ 223,704	$ 147,752
Investing activities	$ 11,169	$ (447,007)	$ (389,168)
Financing activities	$ (371,446)	$ 249,633	$ 160,953

2012 Compared to 2011

Operating Activities:

Net cash provided by operating activities was $93.3 million higher than in 2011 primarily attributable to:

- Cash earnings (income from continuing operations plus non-cash adjustments) were $46.8 million higher than prior year;

- Net inflows from operating assets and liabilities of continuing operations of $42.2 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 $25.4 million contribution in 2012 to our defined benefit plans compared to $11.1 million in 2011; and

- A 14.2 million increase in net cash inflows from discontinued operations in 2012 compared to 2011.

Investing Activities:

Net cash provided by investing activities was $11.2 million in 2012 compared to net cash used in investing activities of $447.0 million in 2011 for a net inflow of $458.2 million. The change was driven by:

- Cash proceeds from assets sold during 2012, including $227.9 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 $107.5 million from the sale of Enserco; and

- In 2012, we had lower capital expenditures of $91.6 million primarily due to the completion of construction of our

Pueblo generation facility.

Financing Activities:

Cash used in financing activities was $371.4 million in 2012, which was an increase in outflow of $621.1 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 $196.0 million primarily due to our continued construction in Colorado;

- In 2012, we repaid our $225.0 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;

- Cash dividends on common stock of $65.3 million were paid in 2012 compared to $59.2 million paid in 2011; and

- In 2011 we issued common stock for proceeds of $123.0 million primarily from an equity forward transaction.

2011 Compared to 2010

Operating Activities:

Cash provided by operating activities was $223.7 million, $76.0 million more than in 2010. In addition to normal working capital changes, our operating cash flow increase was primarily attributable to:

- Cash earnings (income from continuing operations plus non-cash adjustments) were $31.2 million higher than prior year;

- An $11.1 million contribution in 2011 to our defined benefit plans compared to $30.0 million in 2010;

- Increased inflows from operating assets and liabilities of continuing operations of $20.1 million primarily as a result of:

- Increased cash outflows for materials, supplies and fuel primarily including purchases of natural gas at our Gas Utilities and purchases of additional supplies for generation built to support Colorado Electric customers;

- Increased cash inflows primarily due to adjustments to our GCA at our Gas Utilities in regulatory assets and regulatory liabilities combined with inflows from energy efficiency rebates; and

- Cash inflows from accounts receivable and other current assets primarily the result of a settlement reached with the IRS.

- A 15.8 million increase in net cash inflows from discontinued operations in 2011 compared to 2010.

Investing Activities:

Cash used in investing activities was $447.0 million in 2011, which was $57.8 million more than in 2010. Capital additions were $440.7 million in 2011 compared to $472.3 million in 2010. The cash outflows for property, plant and equipment additions reflect significant additions during 2011 and 2010 for completion of construction of 180 megawatts of natural gas-fired electric generation at Colorado Electric and of 200 megawatts of natural gas-fired electric generation at Black Hills Colorado IPP, new transmission at the Electric Utilities and oil and gas property maintenance capital and development drilling. The 2010 outflows were partially offset by cash proceeds of $62.0 million for the sale of a portion of Wygen III to the City of Gillette and $6.1 million for the sale of operating assets in Nebraska to the City of Omaha.

Financing Activities:

Cash provided by financing activities was $249.6 million in 2011, which was an increase of $88.7 million from 2010. During 2011, we issued additional common stock for $123.0 million primarily from an equity forward transaction, paid $59.2 million in cash dividends on common stock, increased short-term borrowings by approximately $196.0 million primarily due to our continued construction in Colorado and repaid $8.4 million primarily for Black Hills Wyoming project financing debt. In 2010, we issued $200 million unsecured notes, increased short-term borrowings by approximately $84.5 million and repaid $59.9 million primarily for Black Hills Power bonds and Black Hills Wyoming project debt.

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. Our Electric Utilities' capital expenditures consist of building Cheyenne Prairie, improvements to generating stations, transmission and distribution lines. Capital expenditures associated with our Gas Utilities are primarily to improve 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 approximately $222 million to build Cheyenne Prairie. We would ultimately expect to finance this new generation with long-term bonds.

Historical Capital Requirements

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

	2012	2011	2010
Property additions [(a)]:			
Utilities -			
Electric Utilities [(b)]	$167,263	$173,078	$232,466
Gas Utilities	45,711	43,954	51,363
Non-regulated Energy -			
Power Generation [(c)]	5,547	98,927	148,191
Coal Mining	13,420	10,438	17,053
Oil and Gas [(d)]	107,839	89,672	40,345
Corporate	7,376	13,279	7,182
Capital expenditures for continuing operations	347,156	429,348	496,600
Discontinued operations investing activities	824	2,359	390
Total expenditures for property, plant and equipment	347,980	431,707	496,990
Common stock dividends	65,262	59,202	56,467
Maturities/redemptions of long-term debt	240,077	8,382	59,926
Discontinued operations financing activities	—	158	2,037
	$653,319	$499,449	$615,420

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

(b) Includes (1) $25.4 million in 2012 for orders placed relating to Cheyenne Prairie which will commence construction in the spring of 2013 and $25.0 million for construction of our 50 percent ownership in the Busch Ranch Wind Project; (2) $65.8 million and $116.3 million in 2011 and 2010, respectively for construction of the 180 megawatt natural gas-fired generation facility at Colorado Electric, excluding transmission; (3) $31.9 million, $23.1 million and $28.0 million in new transmission projects in 2012, 2011 and 2010, respectively; and (4) $13.1 million for Wygen III construction in 2010. During 2010, we received reimbursement of $59.1 million from the joint owners of the Wygen III facility. We retained ownership of 52 percent of the Wygen III coal-fired plant that went into service in 2010.

(c) Includes $98.2 million and $146.2 million in 2011 and 2010, respectively, for construction of the 200 megawatt natural gas-fired power generation facility at Black Hills Colorado IPP.

(d) Approximately $37.9 million and $26.2 of the capital expenditures in 2012 and 2011, respectively, were for our drilling program in the Bakken shale formation. A majority of those assets were sold Sept. 27, 2012.

Forecasted Capital Requirements

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

	2013	2014	2015
Utilities:			
Electric Utilities[1]	$284,200	$230,500	$127,600
Gas Utilities	59,800	58,000	43,000
Non-regulated Energy:			
Power Generation	3,200	4,800	2,400
Coal Mining	7,100	6,000	5,100
Oil and Gas	98,300	84,300	109,100
Corporate	7,500	6,500	5,700
	$460,100	$390,100	$292,900

(1) Capital expenditures for our Electric Utilities include expenditures associated with building Cheyenne Prairie of $139.3 million and $57.7 million in 2013 and 2014, respectively.

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.

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-, the margins for base rate borrowings, Eurodollar borrowings and letters of credit are 0.5 percent, 1.5 percent and 1.5 percent, respectively. A commitment fee is charged on the unused amount of the Revolving Credit Facility which is 0.25 percent based on current credit ratings.

Our Revolving Credit Facility at Dec. 31, 2012 had the following borrowings, outstanding letters of credit and available capacity (in millions):

Credit Facility	Expiration	Current Capacity	Borrowings at Dec. 31, 2012	Letters of Credit at Dec. 31, 2012	Available Capacity at Dec. 31, 2012
Revolving Credit Facility	February 1, 2017	$500.0	$127.0	$36.3	$336.6

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 over our total capital which includes the balance in the numerator plus our net worth. We were in compliance with these covenants as of Dec. 31, 2012.

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.

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 (1.7 percent at Dec. 31, 2012). 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	2012	2011
Black Hills Utility Holdings	$27,852	$273,063
Black Hills Power	(31,645)	(50,477)
Cheyenne Light	5,277	(15,208)
Total Money Pool borrowings from Parent	$1,484	$207,378

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.

Black Hills Power Pollution Control Bonds

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.

Corporate Term Loans

In June 2012, we extended a one-year $150 million unsecured, single draw, term loan (the “Term Loan”) with CoBank, the Bank of Nova Scotia and U.S. Bank to mature on June 24, 2013. The cost of borrowing under the Term Loan is based on a spread of 1.10 percent, over LIBOR (1.35 percent at Dec. 31, 2012). The covenants are substantially the same as those included in the Revolving Credit Facility with an additional minimum net worth requirement. We were in compliance with these covenants as of Dec. 31, 2012.

We have a $100 million two-year term loan (the “Loan”) with J.P Morgan and Union Bank that matures on Sept. 30, 2013. The cost of the borrowings under the Loan is based on a spread of 1.375 percent over LIBOR (1.63 percent at Dec. 31, 2012). Borrowings under the Loan may be prepaid without penalty. The proceeds were used to reduce borrowings on the Revolving Credit Facility. The covenants are substantially the same as under the Revolving Credit Facility. We were in compliance with these covenants as of December 31, 2012.

$225 Million Senior Unsecured Bonds

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 $238.8 million, including accrued interest and a make-whole provision payment of $7.1 million pre-tax.

$250 Million Senior Unsecured Bonds

On May 15, 2014, our 9 percent, $250 million of senior unsecured bonds mature.

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:

- Extend the $150 million and $100 million term loans;
- Analyze the early refinancing of our $250 million, 9 percent senior unsecured bonds that mature in May 2014; and/or
- Review long-term financing options for the estimated $222 million Cheyenne Prairie capital project.

Cross-Default Provisions

Our Revolving Credit Facility and two corporate term loans contain cross-default provisions that would result in a default if BHC or its 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

Our current three-year outlook does not anticipate the need to access the equity markets unless future acquisitions are announced.

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. 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, 2012, 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 2013, our Board of Directors declared a quarterly dividend of $0.38 per share or an annualized equivalent dividend rate of $1.52 per share. The table below provides our historical three-year dividend payout ratio and dividends paid per share.

	2012	2011	2010
Dividend Payout Ratio	80%	118%	82%
Dividends Per Share	$1.48	$1.46	$1.44

Our three-year annualized dividend growth rate was 1.4 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 of 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 January 1, 2005. As of Dec. 31, 2012, 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 December 31, 2012, the restricted net assets at our Electric and Gas Utilities were approximately $263.1 million.

As required by a covenant of the Black Hills Wyoming project financing, Black Hills Non-regulated Holdings, the parent of Black Hills Electric Generation which is the parent of Black Hills Wyoming, has restricted shareholders' equity of at least $100 million. In addition, Black Hills Wyoming holds $7.9 million of restricted cash associated with the project financing requirements.

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 Black Hills Corporation's Senior Unsecured Debt at Dec. 31, 2012:

Rating Agency	Rating	Outlook	Risk Profile

S&P	BBB-	Positive [(a)]	Excellent [(b)]
Moody's	Baa3	Positive [(a)]	Excellent
Fitch	BBB-	Stable	Strong

(a) In October 2012, both Moody's and S&P upgraded our outlook from Stable to Positive.

(b) In July 2012, S&P published its updated credit review, leaving our senior unsecured credit rating of BBB- and upgraded our risk profile from strong to excellent.

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.

We have an interest rate swap with a notional amount of $50 million, which has collateral requirements based upon our corporate credit ratings. At our current credit ratings, we are required to post collateral for any amount by which the swap's negative mark-to-market fair value exceeds $20 million. If our senior unsecured credit rating drops to BB+ or below by S&P or Ba1 or below by Moody's, we would be required to post collateral for the entire amount of the swap's negative mark-to-market fair value. We had $6.0 million cash collateral posted at Dec. 31, 2012.

The following table represents the credit ratings of Black Hills Power's First Mortgage Bonds at Dec. 31, 2012:

Rating Agency	Rating
S&P	BBB+
Moody's	A3
Fitch	A-

We do not have any trigger events (i.e., an acceleration of repayment of outstanding indebtedness, an increase in interest costs or the posting of additional cash collateral) tied to our stock price and have not executed any transactions that require us to issue equity based on our credit ratings or other trigger events. If our senior unsecured credit rating should drop below investment grade, then pricing under our credit agreements would be affected, increasing annual interest expense by approximately $1.0 million pre-tax based on our Dec. 31, 2012 debt balances.

CONTRACTUAL OBLIGATIONS AND OTHER COMMITMENTS

Contractual Obligations

In addition to our capital expenditure programs, we have contractual obligations and other commitments that will need to be funded in the future. The following information summarizes our cash obligations and commercial commitments at December 31, 2012. Actual future costs of estimated obligations may differ materially from these 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]	$1,042,961	$103,973	$262,986	$78,947	$597,055
Unconditional purchase obligations[c]	811,570	187,301	315,703	149,518	159,048
Operating lease obligations[d]	12,756	2,690	5,986	2,505	1,575
Other long-term obligations[e]	50,548	—	—	—	50,548
Employee benefit plans[f]	235,415	26,256	59,458	45,301	104,400
Liability for unrecognized tax benefits in accordance with accounting guidance for uncertain tax positions [g]	40,683	—	13,717	3,278	23,688
Notes payable	277,000	277,000	—	—	—
Total contractual cash obligations[h]	$2,470,933	$597,220	$657,850	$279,549	$936,314

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

(b) The following amounts are estimated for interest payments on long-term debt over the next five years based on a mid-year retirement date for those debt tranches expiring during the identified period: $62.9 million in 2013, $50.7 million in 2014, $39.2 million in 2015, $37.7 million in 2016, and $36.3 million in 2017. Estimated interest payments on variable rate debt are calculated by utilizing the applicable rates as of December 31, 2012.

(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 2012 and price assumptions using existing prices at December 31, 2012. Our transmission obligations are based on filed tariffs as of December 31, 2012. 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 10 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

(f) Represents estimated employer contributions to employee benefit plans through the year 2022.

(g) Years 1-3 include an estimated reversal of approximately $8.2 million associated with the gain deferred from the tax treatment related to the IPP Transaction and the Aquila Transaction.

(h) Amounts in the table exclude: (1) any obligation that may arise from our derivatives, including interest rate swaps and commodity related contracts that have a negative fair value at December 31, 2012. 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 approximately 14 percent of the procurement contracts as of December 31, 2012.

Off-Balance Sheet Commitments

Guarantees

We have entered into various off-balance sheet commitments in the form of guarantees and letters of credit. We provide various guarantees supporting certain of our subsidiaries under specified agreements or transactions. At December 31, 2012, we had outstanding guarantees as indicated in the table below. Of the $175.3 million, $120.8 million was related to performance obligations under subsidiary contracts and $54.5 million was related to indemnification for reclamation and surety bonds of subsidiaries. For more information on these guarantees, see Note 20 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

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

Nature of Guarantee	Outstanding at December 31, 2012	Year Expiring
Guarantees for payment of obligations arising from commodity-related physical and financial transactions by Black Hills Utility Holdings	$70,000	Ongoing
Guarantee for payment obligations relating to a contract to construct 16 wind turbines at Colorado Electric	33,264	2013
Indemnification for subsidiary reclamation/surety bonds	54,509	Ongoing
Guarantee for payment obligations arising from natural gas transportation, storage and services agreement for Colorado Gas	10,000	2013
Guarantee for performance and payment obligation of Black Hills Utility Holdings for natural gas supply	7,500	2013
	$175,273	

Letters of Credit

Letters of credit reduce the borrowing capacity available on our corporate Revolving Credit Facility. We had $36.3 million in letters of credit issued under our Revolving Credit Facility in place at December 31, 2012.

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, fuel procurement for certain of our gas-fired generation assets and variability in revenue due to changes in gas usage at our regulated Electric Utilities and Gas Utilities segments resulting from commodity price changes; and

- Interest rate risk associated with our variable rate credit facility, project financing floating rate debt and our other long-term debt instruments as described in Notes 8 and 9 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.

Our utility customers are exposed to the effect of volatile 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. 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 accordance with state commission guidelines. Accordingly, the hedging activity is recognized in the Consolidated Statements of Income 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):

	2012		2011	
Net derivative liabilities	$(8,533	)	$(16,676	)
Cash collateral	12,930		19,416	
	$4,397		$2,740	

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, introduce commodity price risk and variability in our cash flows. We employ risk management methods to mitigate this commodity price risk and preserve cash flows, and we have adopted guidelines covering hedging for our natural gas and crude oil production. These guidelines have been approved by our Executive Risk Committee and the Board of Directors, and are routinely reviewed by the Audit Committee of our Board of Directors.

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 100 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.

We have entered into agreements to hedge a portion of our estimated 2013 and 2014 natural gas and crude oil production from the Oil and Gas segment. The hedge agreements in place as of Dec. 31, 2012 are as follows:

Natural Gas

	For the Three Months Ended				
	March 31,	June 30,	Sept. 30,	Dec. 31,	Total Year
2013					
Swaps - MMBtu	1,220,000	1,233,000	1,246,000	1,154,000	4,853,000
Weighted Average Price per MMBtu	$4.01	$3.55	$3.33	$3.50	$3.60
2014					
Swaps - MMBtu	950,000	952,500	730,000	730,000	3,362,500
Weighted Average Price per MMBtu	$3.71	$3.65	$3.98	$3.98	$3.81

Crude Oil

	For the Three Months Ended				
	March 31,	June 30,	Sept. 30,	Dec. 31,	Total Year
2013					
Swaps - Bbls	30,000	21,000	15,000	15,000	81,000
Weighted Average Price per Bbl	$101.62	$108.96	$110.20	$101.75	$105.13
Puts - Bbls	30,000	36,000	39,000	36,000	141,000
Weighted Average Price per Bbl	$76.75	$78.96	$79.81	$80.63	$79.15
Calls - Bbls	30,000	36,000	39,000	36,000	141,000
Weighted Average Price per Bbl	$96.50	$97.17	$97.08	$97.25	$97.02
2014					
Swaps - Bbls	45,000	60,000	30,000	30,000	165,000
Weighted Average Price per Bbl	$94.38	$90.65	$89.70	$89.70	$91.32

Our hedge agreements had a fair value, net of cash collateral, of approximately $0.6 million as of Dec. 31, 2012.

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 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, 2012, we had $150.0 million of notional amount floating-to-fixed interest rate swaps, with a maximum term of 4 years. These swaps have been designated as 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 Consolidated Balance Sheets.

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We also have interest rate swaps with a notional amount of $250.0 million, which were entered into for the purpose of hedging interest rate movements that would impact long-term financings that were originally expected to occur in 2008. Based on credit market conditions that transpired during the fourth quarter of 2008, we determined it was probable that the forecasted long-term debt financings would not occur in the time period originally specified and, as a result, the swaps were no longer effective hedges and the hedge relationships were de-designated. Mark-to-market adjustments on the swaps a