BLACK HILLS CORP /SD/
Form 10-K
February 25, 2011

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, 2010

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. ®

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, 2010 $1,102,103,935

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, 2011
Common stock, $1.00 par value	39,262,118 shares

Documents Incorporated by Reference

Portions of the Registrant's Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2011 Annual Meeting of Stockholders to be held on May 25, 2011, 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:

Acquisition Facility	Our $1.0 billion single-draw, senior unsecured facility from which a $383 million draw was used to provide part of the funding for our Aquila Transaction
AFUDC	Allowance for Funds Used During Construction
Annexation Agreement	Agreement with the City of Pueblo, Colorado under which the City of Pueblo annexed the property on which Colorado Electric and Black Hills Colorado IPP are constructing their generation facilities
AOCI	Accumulated Other Comprehensive Income
Aquila	Aquila, Inc.
Aquila Transaction	Our July 14, 2008 acquisition of five utilities from Aquila
ARO	Asset Retirement Obligations
Basin Electric	Basin Electric Power Cooperative
Bbl	Barrel
Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
BHC	Black Hills Corporation; the Company
BHC Pension Plan	The Pension Plan of Black Hills Corporation
BHCCP	Black Hills Corporation Credit Policy
BHCRPP	Black Hills Corporation Risk Policies and Procedures
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 Corporation Plan	Black Hills Corporation Retirement Savings Plan
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
Btu	British thermal unit
CAMR	Clean Air Mercury Rule
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 Light Plan	Cheyenne Light, Fuel and Power Company Retirement Savings Plan

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City of Gillette	The City of Gillette, Wyoming, affiliate of the JPB. The JPB financed the purchase of 23% of Wygen III power plant for the City of Gillette
CO_2	Carbon Dioxide
Colorado Electric	Black Hills Colorado Electric Utility Company, LP, (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings
Colorado Gas	Black Hills Colorado Gas Utility Company, LP, (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings
CPUC	Colorado Public Utilities Commission
CT	Combustion turbine
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
Dth	Dekatherms
EBITDA	Earnings before interest, taxes, depreciation and amortization
EDF	EDF Trading North America, LLC
Enserco	Enserco Energy Inc., a wholly-owned subsidiary of Black Hills Non-regulated Holdings
Enserco Credit Facility	The $250 million committed stand alone credit facility that supports Enserco's marketing and trading operations, which currently expires May 7, 2012
EPA	U. S. Environmental Protection Agency
Equity forward shares	Public offering of 4,000,000 shares of Black Hills Corporation common stock connected with an Equity Forward Agreement
ERISA	Employee Retirement Income Security Act
EWG	Exempt Wholesale Generator
FASB	Financial Accounting Standards Board
FERC	United States Federal Energy Regulatory Commission
Fitch	Fitch Ratings
Forward Agreement	Equity Forward Agreement with J. P. Morgan connected to a public offering of 4,000,000 million shares of Black Hills Corporation common stock
Forward Agreements	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
FTC	Federal Trade Commission
GAAP	Accounting principles generally accepted in the United States of America
GCA	Gas Cost Adjustment
GHG	Greenhouse gases
GIS	Geographic information system
Global Settlement	Settlement with the 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
GSRS	Gas System Reliability Surcharge
Happy Jack	Happy Jack Wind Farm, LLC, owned by Duke Energy Generation Services
Hastings	Hastings Fund Management Ltd
ICE	Intercontinental Exchange
IGCC	Integrated Gasification Combined Cycle
IIF	

IIF BH Investment LLC, a subsidiary of an investment entity advised by JPMorgan Asset Management

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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 production
IPP Transaction	The July 11, 2008 sale of seven of our IPP plants to affiliates of Hastings and IIF
IRS	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
KCC	Kansas Corporation Commission
kV	Kilovolt
KW	Kilowatt
KWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
MACT	Maximum Achievable Control Technology
MAPP	Mid-Continent Area Power Pool
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
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
Native load	Energy required to serve customers within our service territory
NCREIF	National Council of Real Estate Investment Fiduciaries
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
NOx	Nitrogen Oxide
NOL	Net operating loss
NPA	Nebraska Power Association
NPDES	National Pollutant Discharge Elimination System
NPSC	Nebraska Public Service Commission
NQDC	Non-Qualified Deferred Compensation Plan
NYMEX	New York Mercantile Exchange
OCA	Office of Consumer Advocate
OPEC	Organization of the Petroleum Exporting Countries

PCA	Power Cost Adjustment

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PGA	Purchased Gas Adjustment
PPA	Purchase Power 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
PURPA	Public Utility Regulatory Policies Act of 1978
QF	Qualifying Facility
RCRA	Resource Conservation and Recovery Act
Revolving Credit Facility	Our $500 million credit facility used to fund working capital needs, issuance of letters of credit and other corporate purposes, expiring April 14, 2013.
RMSA	Retiree Medical Savings Account
SCADA	Supervisory Control and Data Acquisition
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.
Valencia	Valencia Power, LLC, a former subsidiary of Black Hills Non-regulated Holdings that was sold as part of our IPP Transaction
VEBA	Voluntary Employee Benefit Association
VIE	Variable Interest Entity
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

ACCOUNTING PRONOUNCEMENTS

ASC	Accounting Standards Codification
ASC 310-10-50	ASC 310-10-50, "Receivables - Disclosures"
ASC 715	ASC 715, "Compensation - Retirement Benefits"
ASC 805	ASC 805, "Business Combinations"
ASC 810	ASC 810, "Consolidations"
ASC 810-10-15	ASC 810-10-15, "Consolidation of Variable Interest Entities"
ASC 815	ASC 815, "Derivatives and Hedging"
ASC 820	ASC 820, "Fair Value Measurements and Disclosures"
ASC 932-10-S99	ASC 932-10-S99, "Extractive Activities - Oil and Gas, SEC Materials"
ASC 940-325-S99	ASC 940-325-S99, "Financial Services - Broker and Dealers, Investments - Other"

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 Annual Report on Form 10-K includes "forward-looking statements" as defined by the SEC. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical facts, included in this Form 10-K that address activities, events or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. These forward-looking statements are based on assumptions that we believe are reasonable based on current expectations and projections about future events and industry conditions and trends affecting our business. Whether actual results and developments will conform to our expectations and predictions is subject to a number of risks and uncertainties that, among other things, could cause actual results to differ materially from those contained in the forward-looking statements, including without limitation, the Risk Factors set forth in Item 1A of this Form 10-K and the other reports we file with the SEC from time to time, and the following:

- Macro- and micro-economic changes in the economy and energy industry, including the impact of (i) consolidations and changes in competition, and (ii) general economic and political conditions, including tax rates or policies and inflation rates;
- The timing, volatility and extent of changes in energy and commodity prices, supply or volume, the cost and availability of transportation of commodities, changes in interest or foreign exchange rates, and the demand for our services, any of which can affect our earnings, our financial liquidity and the underlying value of our assets;
- Our ability to comply, or to make expenditures required to comply, with changes in laws and regulations, particularly those relating to energy markets, taxation, safety and protection of the environment, and our ability to recover those expenditures in customer rates, where applicable;
- Federal and state laws concerning climate change and air emissions, including emission reduction mandates, carbon emissions and renewable energy portfolio standards, which may materially increase our generation and production costs and could render some of our generating units uneconomical to operate and maintain, or which could require closure of one or more of our generating units;
- Changes in business, regulatory compliance and financial reporting practices arising from the enactment of the Energy Policy Act of 2005 and subsequent rules and regulations promulgated thereunder;
- The effect of Dodd-Frank and the regulations to be adopted thereunder on our use of derivative instruments in connection with our energy marketing activities and to hedge our expected production of oil and natural gas and on our use of interest rate derivative instruments;

- Changes in state laws or regulations that could cause us to curtail our independent power production or exploration and production activities;
- Our ability to successfully integrate and profitably operate any future acquisitions;
- Our ability to obtain adequate cost recovery for our utility operations through regulatory proceedings and receive favorable rulings in periodic applications to recover costs for fuel, transportation, transmission and purchased power in our regulated utilities;
- Our ability to receive regulatory approval to recover in rate base our expenditures for new power generation facilities or other utility infrastructure;

- Our ability to recover our borrowing costs, including debt service costs, in our customer rates;
- The extent of our success in connecting natural gas supplies to gathering, processing and pipeline systems;
- Our ability to minimize losses related to defaults on amounts due from customers and counterparties, including counterparties to trading and other commercial transactions;
- The timing and extent of scheduled and unscheduled outages of power generation facilities;
- Our ability to complete the permitting, construction, start-up and operation of power generating facilities in a cost-effective and timely manner;
- Our ability to accurately estimate demand from our customers for natural gas;
- Weather and other natural phenomena;
- Our ability to meet forecasted production volumes for our oil and gas properties, which may be dependent upon issuance by federal, state and tribal governments, or agencies thereof, of drilling, environmental and other permits, and the availability of specialized contractors, work force and equipment, or the possibility of reductions in our drilling program resulting from the current economic climate and commodity prices, which also may prevent us from maintaining production rates and replacing reserves for our oil and gas properties;
- The amount of collateral required to be posted from time to time in our transactions;
- Our ability to effectively use derivative financial instruments to hedge commodity, currency exchange rate and interest rate risks;
- Our ability to provide accurate estimates of proved oil and gas reserves, coal reserves and future production rates and associated costs;
- Price risk due to marketable securities held as investments in employee benefit plans;
- Our ability to successfully maintain our corporate credit rating;
- Our ability to access revolving credit capacity and comply with loan covenants;
- Capital market conditions and market uncertainties related to interest rates, which may affect our ability to raise capital on favorable terms;
- The amount and timing of capital deployment in new investment opportunities or for the repurchase of debt or stock;
- Our ability to continue paying our regular quarterly dividend;
- Our ability to obtain permanent financing for capital expenditures on reasonable terms either through long-term debt or issuance of equity;
- The effect of accounting policies issued periodically by accounting standard-setting bodies;

- The accounting treatment and earnings impact associated with interest rate swaps;
- The possibility that we may be required to take impairment charges to reduce the carrying value of some of our long-lived assets when indicators of impairment emerge;
- The possibility that we may be required to take impairment charges under the SEC's full cost ceiling test for the accumulated costs of our natural gas and oil reserves;
- The outcome of any ongoing or future litigation or similar disputes and the impact of any such outcome or related settlements on our financial condition or results of operations;

- Additional liabilities for environmental conditions, including remediation and reclamation obligations, under environmental laws;
- Our ability to successfully complete labor negotiations with labor unions with whom we have collective bargaining agreements and for which we are currently in, or are soon to be in, contract renewal negotiations; and
- The cost and effect on our business, including insurance, resulting from terrorist actions or responses to such actions or events.

New factors that could cause actual results to differ materially from those described in forward-looking statements emerge from time to time, and it is not possible for us to predict all such factors, or the extent to which any such factor or combination of factors may cause actual results to differ from those contained in any forward-looking statement. We assume no obligation to update publicly any such forward-looking statements, whether as a result of new information, future events or otherwise.

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" and "our"), is a diversified energy company headquartered in Rapid City, South Dakota. Our predecessor company, Black Hills Power and Light Company, was incorporated and began providing electric utility service in 1941. It was formed through the purchase and combination of several existing electric utilities and related assets, some of which had served customers in the Black Hills region since 1883. In 1956, the Company began producing, selling and marketing various forms of energy through its non-regulated business.

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 Oil and Gas, Power Generation, Coal Mining, and Energy Marketing segments, as shown below. At December 31, 2010, we had 2,124 employees, 705 of whom were represented by union locals.

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

Our Electric Utilities segment generates, transmits and distributes electricity to approximately 201,000 customers in South Dakota, Wyoming, Colorado and Montana and includes the operations of Cheyenne Light, a combination electric and gas utility, and its approximately 34,500 gas utility customers in Wyoming. Our Gas Utilities segment serves approximately 527,000 natural gas utility customers in Colorado, Nebraska, Iowa and Kansas. Our Electric Utilities own 687 MWs of generation and 8,038 miles of electric transmission and distribution lines, and our Gas Utilities own 626 miles of intrastate gas transmission pipelines and 19,638 miles of gas distribution mains and service lines. Our Electric and Gas Utilities generated income from continuing operations of $74.6 million for the year ended December 31, 2010 and had total assets of $2.6 billion at December 31, 2010.

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 Coal Mining segment produces coal at our coal mine near Gillette, Wyoming, and our Energy Marketing segment is engaged in marketing of natural gas, crude oil, coal, power, environmental products and related services, in the United States and Canada. Our Power Generation segment produces electric power from our generating plants and sells the electric capacity and energy primarily under long-term contracts. In 2008, we sold seven IPP plants previously reported in our Power Generation segment, which resulted in the operations of these plants being reported as discontinued operations. Our Non-regulated Energy Group generated income from continuing operations of $13.6 million in the year ended December 31, 2010 and had total assets of $1.1 billion at December 31, 2010.

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, particularly Note 17 to the Consolidated Financial Statements in this Annual Report on Form 10-K.

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 201,000 customers in South Dakota, Wyoming, Colorado and Montana. Additionally, Cheyenne Light distributes natural gas to approximately 34,500 natural gas utility customers in Wyoming. Our electric generating facilities and purchased power contracts supply electricity principally to our own distribution systems. Additionally, we sell excess power to other utilities and marketing companies, including affiliates.

We conduct natural gas utility operations on a state-by-state basis through our Colorado Gas, Iowa Gas, Kansas Gas, and Nebraska Gas subsidiaries. Our Gas Utilities distribute and transport natural gas to our customers through our distribution network to approximately 527,000 customers in Colorado, Iowa, Kansas and Nebraska. We also provide related services that include appliance repairs, gas technical services and the sale of temporarily-available, contractual pipeline capacity from our suppliers.

In addition to our regulated operations, we also provide services through our Service Guard product line to approximately 63,000 customers in Colorado, Iowa, Kansas and Nebraska. Service Guard primarily provides appliance repair services through company technicians and third party service providers.

Electric Utilities Segment

Capacity and Demand

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

	System Peak Demand (in MW)					
	2010		2009		2008	
	Summer	Winter	Summer	Winter	Summer	Winter
Black Hills Power	396	377	387	392	409	407
Cheyenne Light	176	164	169	171	166	168
Colorado Electric	384	289	365	296	306 (a)	298 (a)
Total Electric Utilities Peak Demands	956	830	921	859	881	873

(a) For the period July 14, 2008 to December 31, 2008.

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Regulated Power Plants

As of December 31, 2010, 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, WY	52.0 %	57.2	2010
Neil Simpson II	Coal	Gillette, WY	100.0 %	90.0	1995
Wyodak [(2)]	Coal	Gillette, WY	20.0 %	72.4	1978
Osage [(3)]	Coal	Osage, WY	100.0 %	34.5	1948-1952
Ben French	Coal	Rapid City, SD	100.0 %	25.0	1960
Neil Simpson I	Coal	Gillette, WY	100.0 %	21.8	1969
Neil Simpson CT	Gas	Gillette, WY	100.0 %	40.0	2000
Lange CT	Gas	Rapid City, SD	100.0 %	40.0	2002
Ben French Diesel #1-5	Oil	Rapid City, SD	100.0 %	10.0	1965
Ben French CTs #1-4	Gas/Oil	Rapid City, SD	100.0 %	100.0	1977-1979
Cheyenne Light:					
Wygen II	Coal	Gillette, WY	100.0 %	95.0	2008
Colorado Electric [(4)]:					
W.N. Clark #1-2 [(5)]	Coal	Canon City, CO	100.0 %	42.0	1955, 1959
Pueblo #6	Gas	Pueblo, CO	100.0 %	20.0	1949
Pueblo #5	Gas	Pueblo, CO	100.0 %	9.0	1941, 2001
AIP Diesel	Oil	Pueblo, CO	100.0 %	10.0	2001
Diesel #1-5	Oil	Pueblo, CO	100.0 %	10.0	1964
Diesel #1-5	Oil	Rocky Ford, CO	100.0 %	10.0	1964
Total MW Owned Capacity				686.9	

(1) Construction of Wygen III, a 110 MW mine-mouth coal-fired power plant was completed in April 2010. Black Hills Power operates the plant and owns a 52% interest in the facility, MDU owns a 25% interest and the City of Gillette owns a 23% interest. Our WRDC coal mine furnishes all of the coal fuel supply for the plant.
(2) Wyodak is a 362 MW mine-mouth coal-fired plant owned 80% by PacifiCorp and 20% by Black Hills Power. This baseload plant is operated by PacifiCorp and our WRDC coal mine furnishes all of the coal fuel supply for the plant.
(3) Operations at the Osage plant were suspended October 1, 2010 due to the availability of more economical generation alternatives.
(4) The construction of two 90 MW gas-fired power generation facilities is underway to support the customers of Colorado Electric. These facilities are expected to be completed by December 31, 2011.
(5) In December 2010, Colorado Electric received a final order from CPUC which approved the retirement of its W.N. Clark coal-fired generation facility by December 31, 2013 and granted a presumption of need in the amount of 42 MW for replacement of the plant. Colorado Electric will file a Certificate of Public Convenience and Necessity to provide justification for an additional 50 MW of generating capacity to allow the construction of a third 92 MW GE LMS100 natural gas-fired generator at the Pueblo Airport Generation Station where two 90 MW facilities are currently under construction.

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 MWh (dollars per MWh):

Fuel Source	2010	2009	2008[1]
Coal	$12.77	$13.99	$11.41
Gas and Oil	$131.28	$85.52	$88.60
Total Average Fuel Cost	$13.57	$15.22	$13.18
Purchased Power[2]	$30.23	$28.93	$38.06

(1) 2008 includes Colorado Electric from July 14, 2008 through December 31, 2008.
(2) Includes Happy Jack commencing in October 2008, and Silver Sage commencing in October 2009.

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	2010	2009	2008
Coal-fired	42 %	39 %	44 %
Gas and Oil	—	1	1
Total Generated	42	40	45
Purchased	58	60	55
Total	100 %	100 %	100 %

Purchased Power. Various agreements have been executed 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 in 2023, which provides for the purchase of 50 MW of coal-fired baseload power;
- Black Hills Power's reserve capacity integration agreement with PacifiCorp expiring in 2012, which makes available 100 MW of reserve capacity in connection with the utilization of the Ben French CT units;
- Colorado Electric's PPA with PSCo expiring at the end of 2011, whereby Colorado Electric purchases a majority of its power. The contract provides for 300 MW of capacity and energy in 2011;
- Colorado Electric's 20-year PPA with Black Hills Colorado IPP, beginning on January 1, 2012 and expiring in 2031, which will provide 200 MW of power to Colorado Electric from Black Hills Colorado IPP's combined-cycle turbines, which are currently under construction;
- Cheyenne Light's PPA with Black Hills Wyoming expiring in August 2011 whereby Black Hills Wyoming provides 40 MW of energy and capacity from its Gillette CT.

- Cheyenne Light's PPA with Black Hills Wyoming expiring December 31, 2022 whereby Black Hills Wyoming provides 60 MW of unit-contingent capacity and energy from its Wygen I facility. The PPA includes an option for Cheyenne Light to purchase Black Hills Wyoming's ownership interest in the Wygen I facility between 2013 and 2019. The purchase price related to the option is $2.55 million per MW which is equivalent to the estimated initial per MW price of new construction of the Wygen III facility. This 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 in 2028, which provides up to 29.4 MW of wind energy from the Happy Jack Wind Farm to Cheyenne Light. Under a separate intercompany agreement, Cheyenne Light sells 50% of the facility's output to Black Hills Power;

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

- Cheyenne Light's 20-year PPA with Duke Energy, expiring in 2029, provides 30 MW of wind energy from the Silver Sage wind farm to Cheyenne Light. Under a separate intercompany agreement, Cheyenne Light sells 20 MW of energy from Silver Sage to Black Hills Power.

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

- In conjunction with MDU's April 2009 purchase of a 25% ownership interest in Wygen III, an agreement to supply 74 MW of capacity and energy through 2016 was modified. The sales to MDU have been integrated into Black Hills Power's control area and are considered part of our firm native load. MWs from the Wygen III unit are deemed to supply a portion of the required 74 MW. During periods of reduced production at Wygen III, or during periods when Wygen III is off-line, MDU will be provided with 25 MW from our other generation facilities or from system purchases with reimbursement of costs by MDU;

- Black Hills Power's agreement with the City of Gillette to dispatch the City of Gillette's 23% of Wygen III's net generating capacity for the life of the plant. Upon the City of Gillette's July 2010 purchase of a 23% ownership interest in Wygen III, a seven year PPA with the City of Gillette that went into effect in April 2010, was terminated. The City of Gillette's 23 MW of Wygen III capacity has been integrated into Black Hills Power's control area and are considered part of our firm native load. During periods of reduced production at Wygen III, or during periods when Wygen III is off-line, we will provide the City of Gillette with its first 23 MW from our 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 their operating component of spinning reserves;

- Black Hills Power's agreement to supply 20 MW of energy and capacity to MEAN under a contract that expires in 2023. This contract is unit-contingent based on the availability of our Neil Simpson II and Wygen III plants, with capacity purchase decreasing to 15 MW in 2018, 12 MW in 2020 and 10 MW in 2022. The unit-contingent capacity amounts from Wygen III and Neil Simpson II are as follows:

2010-2017	20 MW - 10 MW contingent on Wygen III and 10 MW contingent on Neil Simpson II
2018-2019	15 MW - 10 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II
2020-2021	12 MW - 6 MW contingent on Wygen III and 6 MW contingent on Neil Simpson II
2022-2023	10 MW - 5 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II;

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Black Hills Power's five-year PPA with MEAN which commenced in May 2010 whereby MEAN will purchase 5 MW of unit-contingent capacity from Neil Simpson II and 5 MW of unit-contingent capacity from Wygen III; and

- Cheyenne Light's agreement with Basin Electric whereby Cheyenne Light will supply 40 MW of capacity and energy through March 31, 2013 and a separate agreement whereby Cheyenne Light will receive 40 MW of capacity and energy from Basin Electric through March 31, 2013. The agreements become effective on March 14, 2011, and terminate prior agreements under which Cheyenne Light supplies Basin Electric with 80 MW of energy and capacity, and Basin Electric supplies Cheyenne Light with 80 MW of energy and capacity.

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, 2010, our regulated Electric Utilities owned or leased the electric transmission and distribution lines shown below:

Utility	State	Transmission (in Line Miles)	Distribution (in Line Miles)
Black Hills Power	SD, WY	565	2,933
Black Hills Power - Jointly Owned [(1)]	SD, WY	47	—
Cheyenne Light	SD, WY	25	1,176
Colorado Electric	CO	260	3,032

(1) Through Black Hills Power, we own 35% of a DC transmission tie that interconnects the Western and Eastern transmission grids, which are independently-operated transmission grids serving the western United States and eastern United States, respectively. This transmission tie, which is 65% owned by Basin Electric, provides transmission access to both the WECC region in the West and the MAPP region in the East. The transfer capacity of the tie is 200 MW from West to East, and 200 MW from East to West. Black Hills Power's electric system is located in the WECC region. This transmission tie allows us to buy and sell energy in the Eastern grid without having to isolate and physically reconnect load or generation between the two transmission grids, thus enhancing the reliability of our system. It accommodates scheduling transactions in both directions simultaneously, provides additional opportunities to sell excess generation or to make economic purchases to serve our native load and contract obligations, and enables us to take advantage of power price differentials between the two grids.

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

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

Shared Services Agreement. 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 used by an affiliate entity. This agreement commenced during 2010.

Operating Statistics

The following tables summarize sales revenues, quantities and customers for our Electric Utilities. Amounts shown for 2008 include Colorado Electric from our July 14, 2008 acquisition date through December 31, 2008.

Sales Revenues (in thousands)

	2010	2009	2008
Residential:			
Black Hills Power	$53,549	$48,586	$46,854
Cheyenne Light	29,506	29,198	31,394
Colorado Electric	76,596	66,548	32,620
Total Residential	159,651	144,332	110,868
Commercial:			
Black Hills Power	65,997	59,897	58,289
Cheyenne Light	52,765	51,280	51,609
Colorado Electric	66,490	56,002	28,531
Total Commercial	185,252	167,179	138,429
Industrial:			
Black Hills Power	22,621	20,014	21,432
Cheyenne Light	10,542	11,121	9,716
Colorado Electric	28,812	31,067	16,280
Total Industrial	61,975	62,202	47,428
Municipal:			
Black Hills Power	3,029	2,735	2,734
Cheyenne Light	1,293	932	973
Colorado Electric	10,443	4,408	2,289
Total Municipal	14,765	8,075	5,996
Contract Wholesale:			
Black Hills Power	22,996	25,358	26,643
Off-system Wholesale:			
Black Hills Power	36,354	32,212	63,770
Cheyenne Light	9,750	8,565	6,105
Colorado Electric	10,859	14,008	11,194
Total Off-system Wholesale	56,963	54,785	81,069
Other Sales Revenue:			
Black Hills Power	25,217	18,277	12,950
Cheyenne Light	3,230	718	394
Colorado Electric	2,374	4,226	1,346
Total Other Sales Revenue	30,821	23,221	14,690
Total Sales Revenues	$532,423	$485,152	$425,123

Quantities Generated and Purchased (MWh)

	2010	2009	2008
Generated -			
Coal-fired:			
Black Hills Power	1,987,037	1,721,074	1,731,838
Cheyenne Light	734,241	766,943	740,051
Colorado Electric	257,896	252,603	138,424
Total Coal	2,979,174	2,740,620	2,610,313
Gas and Oil-fired:			
Black Hills Power	19,269	46,723	61,801
Cheyenne Light	—	—	—
Colorado Electric	930	2,705	306
Total Gas and Oil	20,199	49,428	62,107
Total Generated:			
Black Hills Power	2,006,306	1,767,797	1,793,639
Cheyenne Light	734,241	766,943	740,051
Colorado Electric	258,826	255,308	138,730
Total Generated	2,999,373	2,790,048	2,672,420
Purchased -			
Black Hills Power	1,440,579	1,686,455	1,703,088
Cheyenne Light	696,756	651,201	590,622
Colorado Electric	1,969,896	1,991,058	1,028,029
Total Purchased	4,107,231	4,328,714	3,321,739
Total Generated and Purchased	7,106,604	7,118,762	5,994,159

Quantity (MWh)			
	2010	2009	2008
Residential:			
Black Hills Power	547,193	529,825	524,413
Cheyenne Light	261,607	255,134	255,345
Colorado Electric	628,553	589,526	284,294
Total Residential	1,437,353	1,374,485	1,064,052
Commercial:			
Black Hills Power	720,119	723,360	699,734
Cheyenne Light	603,323	583,986	586,151
Colorado Electric	726,005	666,563	330,870
Total Commercial	2,049,447	1,973,909	1,616,755
Industrial:			
Black Hills Power	382,562	353,041	414,421
Cheyenne Light	161,082	174,792	144,179
Colorado Electric	347,673	452,584	235,218
Total Industrial	891,317	980,417	793,818
Municipal:			
Black Hills Power	33,908	33,948	34,368
Cheyenne Light	6,477	3,456	3,669
Colorado Electric	113,689	37,244	19,740
Total Municipal	154,074	74,648	57,777
Contract Wholesale:			
Black Hills Power	468,782	645,297	665,795
Off-system Wholesale:			
Black Hills Power	1,163,058	1,009,574	1,074,398
Cheyenne Light	311,524	309,122	246,542
Colorado Electric	274,942	373,495	230,333
Total Off-system Wholesale	1,749,524	1,692,191	1,551,273
Total Quantity Sold:			
Black Hills Power	3,315,622	3,295,045	3,413,129
Cheyenne Light	1,344,013	1,326,490	1,235,886
Colorado Electric	2,090,862	2,119,412	1,100,455
Total Quantity Sold	6,750,497	6,740,947	5,749,470
Losses and Company Use:			
Black Hills Power	131,263	159,207	83,598
Cheyenne Light	86,984	91,654	94,787
Colorado Electric	137,860	126,954	66,304
Total Losses and Company Use	356,107	377,815	244,689
Total Energy	7,106,604	7,118,762	5,994,159

Degree Days

	2010		2009		2008	
	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average
Heating Degree Days:						
Actual -						
Black Hills Power	7,272	1 %	7,753	8 %	7,676	6 %
Cheyenne Light	7,033	(5)%	7,411	— %	7,435	1 %
Colorado Electric	5,518	(1)%	5,546	(1)%	2,204	(5)%
Cooling Degree Days:						
Actual -						
Black Hills Power	532	(11)%	354	(41)%	482	(19)%
Cheyenne Light	345	26 %	203	(26)%	372	36 %
Colorado Electric	1,074	16 %	804	(13)%	500	(12)%

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.

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.

Electric Customers at Year-End

	2010	2009	2008
Residential:			
Black Hills Power	54,811	54,470	53,765
Cheyenne Light	34,913	35,943	35,205
Colorado Electric	81,902	81,622	81,561
Total Residential	171,626	172,035	170,531
Commercial:			
Black Hills Power	12,779	12,261	12,213
Cheyenne Light	4,132	4,932	4,563
Colorado Electric	11,185	11,101	11,155
Total Commercial	28,096	28,294	27,931
Industrial:			
Black Hills Power	40	38	40
Cheyenne Light	2	2	2
Colorado Electric	63	90	93
Total Industrial	105	130	135
Contract Wholesale:			
Black Hills Power	3	3	3
Other Electric Customers:			
Black Hills Power	309	143	3,010
Cheyenne Light	254	13	6
Colorado Electric	510	499	480
Total Other Electric Customers	1,073	655	3,496
Total Customers:			
Black Hills Power	67,942	66,915	69,031
Cheyenne Light	39,301	40,890	39,776
Colorado Electric	93,660	93,312	93,289
Total Customers	200,903	201,117	202,096

Cheyenne Light Natural Gas Distribution

Cheyenne Light's natural gas distribution system serves natural gas customers in Cheyenne and other portions of Laramie County, Wyoming. The following table summarizes certain operating information:

	2010	2009	2008
Sales Revenues (in thousands):			
Residential	$22,562	$21,495	$28,059
Commercial	10,801	9,821	13,751
Industrial	3,425	3,537	5,668
Other Sales Revenues	803	760	818
Total Sales Revenues	$37,591	$35,613	$48,296
Sales Margins (in thousands):			
Residential	$10,004	$10,219	$10,083
Commercial	3,376	3,266	3,177
Industrial	427	509	483
Other Sales Margins	720	760	818
Total Sales Margins	$14,527	$14,754	$14,561
Volumes Sold (Dth):			
Residential	2,636,839	2,516,699	2,582,248
Commercial	1,572,638	1,502,002	1,501,025
Industrial	667,062	722,776	689,945
Total Volumes Sold	4,876,539	4,741,477	4,773,218
Customers	34,461	33,942	33,243

Gas Utilities Segment

At December 31, 2010, 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	122	2,967	871
Nebraska	51	3,406	3,462
Iowa	170	2,753	2,313
Kansas	283	2,578	1,288
Total	626	11,704	7,934

Operating Statistics

The following tables summarize revenues, sales margins, volumes, degree days and customers for our Gas Utilities. Amounts shown for 2008 include Gas Utilities from our July 14, 2008 acquisition date through December 31, 2008.

Revenues (in thousands)	2010	2009	2008
Residential:			
Colorado	$55,211	$62,732	$27,928
Nebraska	120,365	127,120	60,624
Iowa	105,255	113,781	47,338
Kansas	69,859	70,848	31,456
Total Residential	350,690	374,481	167,346
Commercial:			
Colorado	11,880	13,357	6,356
Nebraska	40,720	43,472	20,705
Iowa	46,762	54,587	26,003
Kansas	21,953	22,629	10,092
Total Commercial	121,315	134,045	63,156
Industrial:			
Colorado	1,409	1,348	1,495
Nebraska	3,126	3,425	1,640
Iowa	2,243	2,191	1,581
Kansas	14,312	11,057	14,667
Total Industrial	21,090	18,021	19,383
Other Sales Revenue:			
Colorado	97	100	39
Nebraska	1,960	2,077	907
Iowa	836	1,073	457
Kansas	3,451	3,213	1,600
Total Other Sales Revenue	6,344	6,463	3,003
Total Distribution:			
Colorado	68,597	77,537	35,818
Nebraska	166,171	176,094	83,876
Iowa	155,096	171,632	75,379
Kansas	109,575	107,747	57,815
Total Distribution	499,439	533,010	252,888
Transportation:			
Colorado	784	732	278
Nebraska	11,289	10,569	4,703
Iowa	3,708	3,876	1,609
Kansas	5,471	5,389	2,409
Total Transportation	21,252	20,566	8,999
Total Regulated:			

Colorado	69,381	78,269	36,096
Nebraska	177,460	186,663	88,579
Iowa	158,804	175,508	76,988
Kansas	115,046	113,136	60,224
Total Regulated Revenues	520,691	553,576	261,887
Non-regulated Services	30,016	26,736	15,189
Total Revenues	$550,707	$580,312	$277,076

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Sales Margins (in thousands)	2010	2009	2008
Residential:			
Colorado	$18,153	$17,443	$5,984
Nebraska	49,074	44,638	19,460
Iowa	44,269	42,734	16,335
Kansas	29,591	28,999	12,436
Total Residential	141,087	133,814	54,215
Commercial:			
Colorado	3,215	3,176	1,131
Nebraska	11,965	11,785	4,952
Iowa	11,616	12,749	5,210
Kansas	6,544	6,484	2,693
Total Commercial	33,340	34,194	13,986
Industrial:			
Colorado	360	375	232
Nebraska	379	431	173
Iowa	235	244	105
Kansas	1,878	1,766	1,041
Total Industrial	2,852	2,816	1,551
Other Sales Margins:			
Colorado	97	101	39
Nebraska	1,960	2,077	907
Iowa	836	1,073	457
Kansas	2,722	2,312	1,177
Total Other Sales Margins	5,615	5,563	2,580
Total Distribution:			
Colorado	21,825	21,095	7,386
Nebraska	63,378	58,931	25,492
Iowa	56,956	56,800	22,107
Kansas	40,735	39,561	17,347
Total Distribution	182,894	176,387	72,332
Transportation:			
Colorado	784	732	278
Nebraska	11,289	10,569	4,703
Iowa	3,708	3,876	1,609
Kansas	5,470	5,389	2,409
Total Transportation	21,251	20,566	8,999
Total Regulated:			
Colorado	22,609	21,827	7,664
Nebraska	74,667	69,500	30,195
Iowa	60,664	60,676	23,716

Kansas	46,205	44,950	19,756
Total Regulated Sales Margins	204,145	196,953	81,331
Non-regulated Services	12,845	11,643	3,895
Total Sales Margins	$216,990	$208,596	$85,226

Volumes (in Dth)	2010	2009	2008
Residential:			
Colorado	6,284,559	6,355,275	2,344,549
Nebraska	12,210,574	12,619,682	5,115,805
Iowa	10,556,045	10,976,268	4,126,150
Kansas	6,926,928	6,878,243	2,682,850
Total Residential	35,978,106	36,829,468	14,269,354
Commercial:			
Colorado	1,473,924	1,444,360	563,169
Nebraska	5,009,105	5,189,630	2,133,433
Iowa	6,061,954	6,597,035	2,749,234
Kansas	2,673,805	2,696,870	1,063,356
Total Commercial	15,218,788	15,927,895	6,509,192
Industrial:			
Colorado	259,985	263,134	164,112
Nebraska	544,457	581,892	248,256
Iowa	354,435	333,324	196,841
Kansas	2,718,767	2,524,126	1,586,306
Total Industrial	3,877,644	3,702,476	2,195,515
Other Volumes:			
Colorado	—	—	—
Nebraska	1,341	1,400	320
Iowa	69,306	68,290	18,301
Kansas	120,445	141,909	60,917
Total Other Volumes	191,092	211,599	79,538
Total Distribution:			
Colorado	8,018,468	8,062,769	3,071,830
Nebraska	17,765,477	18,392,604	7,497,814
Iowa	17,041,740	17,974,917	7,090,526
Kansas	12,439,945	12,241,148	5,393,429
Total Distribution	55,265,630	56,671,438	23,053,599
Transportation:			
Colorado	808,859	807,999	347,822
Nebraska	27,327,173	25,311,501	12,930,165
Iowa	17,422,525	14,915,602	6,312,050
Kansas	14,320,893	14,069,182	7,215,038
Total Transportation	59,879,450	55,104,284	26,805,075
Total Volumes:			
Colorado	8,827,327	8,870,768	3,419,652
Nebraska	45,092,650	43,704,105	20,427,979

Iowa	34,464,265	32,890,519	13,402,576
Kansas	26,760,838	26,310,330	12,608,467
Total Volumes	115,145,080	111,775,722	49,858,674

Degree Days

	2010		2009		2008	
	Actual	Variance From 30-Year Average	Actual	Variance From 30-Year Average	Actual *	Variance From 30-Year Average *
Heating Degree Days:						
Colorado	5,803	(9)%	6,299	2%	2,376	(7)%
Nebraska	6,222	(5)%	6,238	5%	2,458	—%
Iowa	6,934	(1)%	7,279	6%	2,909	3%
Kansas	4,918	—%	4,989	—%	1,897	(3)%
Combined	6,101	(3)%	6,285	(11)%	2,471	—%

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* Gas Utilities acquired on July 14, 2008.

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. For service areas that have weather normalization operations, normal degree days are used instead of actual degree days in computing the total number of heating degree days. The combined heating degree days are calculated based on a weighted average of total customers by state.

The following table summarizes the Gas Utilities' customers as of December 31:

Customers	2010	2009	2008
Residential:			
Colorado	66,766	65,586	64,601
Nebraska	176,244	179,873	177,432
Iowa	134,782	133,712	133,442
Kansas	97,844	97,446	96,593
Total Residential	475,636	476,617	472,068
Commercial:			
Colorado	3,620	3,590	3,579
Nebraska	15,221	15,218	15,034
Iowa	15,300	15,403	15,467
Kansas	9,469	9,510	9,463
Total Commercial	43,610	43,721	43,543
Industrial:			
Colorado	208	207	208
Nebraska	149	149	149
Iowa	93	90	84
Kansas	1,394	1,351	1,267
Total Industrial	1,844	1,797	1,708
Transportation:			
Colorado	22	22	21
Nebraska	4,270	4,579	4,758
Iowa	392	389	397
Kansas	1,054	1,077	1,174
Total Transportation	5,738	6,067	6,350
Other:			
Colorado	—	—	—
Nebraska	2	2	2
Iowa	68	71	69
Kansas	8	8	8
Total Other	78	81	79
Total Customers:			
Colorado	70,616	69,405	68,409
Nebraska	195,886	199,821	197,375
Iowa	150,635	149,665	149,459
Kansas	109,769	109,392	108,505
Total Customers	526,906	528,283	523,748

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 in comparison to other investor-owned electric utilities. 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 patterns throughout our service territories, and as a result, a significant amount of natural gas revenues are normally recognized in the heating season consisting of the first and fourth quarters.

Competition

We face competition from other utilities and non-affiliated IPP companies for the right to provide power and capacity for Colorado Electric. However, 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 require competitive bidding for generation supply.

Regulation and Rates

State Regulation

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 our utilities are allowed to charge for their 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 state to secure bonds or other securities.

We distribute natural gas in five states. All of our Gas Utilities, and Cheyenne Light's natural gas distribution, have gas cost adjustments that allow us to pass the prudently-incurred cost of gas through to the customer. In Kansas and Nebraska, we are also allowed to recover the portion of uncollectible accounts related to gas costs through the gas cost adjustments. 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. In Kansas, we also have tariffs that provide for more timely recovery for certain capital expenditures and fluctuations in property taxes. In Nebraska, legislation was passed in 2009 to authorize the NPSC to provide for more timely recovery from our customers for certain capital expenditures between rate cases.

We produce and distribute power in four states. The regulatory provisions for recovering the costs to produce electricity vary by state. In South Dakota, Wyoming, Colorado and Montana, we have cost adjustment mechanisms for our Electric Utilities that serve a purpose similar to the cost adjustment mechanisms in our Gas Utilities. At Cheyenne Light, our pass-through mechanism relating to transmission, fuel and purchased power costs is subject to a $1.0 million threshold: we collect or refund 95% of the increase or decrease that exceeds the $1.0 million threshold, and we absorb the increase or retain the savings for changes above or below the threshold.

Until April 1, 2010 South Dakota had three adjustment mechanisms: transmission, steam plant fuel (coal) and conditional energy cost adjustment. The transmission and steam plant fuel adjustment clauses required an annual adjustment to rates for actual costs, therefore any savings or increased costs were passed on to the South Dakota customers. The conditional energy cost adjustment related to purchased power and natural gas used to generate electricity. These costs were subject to calendar year $2.0 million and $1.0 million thresholds where Black Hills Power absorbed the first $2.0 million of increased costs or retained the first $1.0 million in savings. Beyond these thresholds, costs or savings were passed on to South Dakota customers through annual calendar-year filings.

In South Dakota beginning April 1, 2010, the steam plant fuel and conditional energy cost adjustment were combined into a single cost adjustment called the Fuel and Purchased Power Adjustment clause. The Fuel and Purchased Power Adjustment Clause provides for the direct recovery of increased fuel and purchased power costs incurred to serve South Dakota customers. As of April 1, 2010, the Fuel and Purchased Power Adjustment clause was modified in the rate case settlement to contain a power marketing operating income sharing mechanism in which South Dakota customers will receive a credit equal to 65% of 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 Purchase Power Cost Adjustment was instituted.

In Colorado, we have a cost adjustment for increases or decreases in purchased power and fuel costs and a transmission cost adjustment. The cost adjustment clause provides for the direct recovery of increased purchased power and fuel costs or the issuance of credits for decreases in purchased power and fuel costs. The transmission cost adjustment is a 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.

In Colorado, beginning in November 2010, the CPUC approved the implementation of a Purchased Capacity Cost Adjustment, the purpose of which is to recover the increase in capacity cost related to Colorado Electric's purchase power agreement with PSCo.

The above mechanisms allow the utilities 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. In some instances, such as the transmission cost adjustment in Colorado, the utility has the opportunity to earn its authorized return on new capital investment.

Certain states where we conduct electric utility operations have adopted renewable energy portfolio standards that require or encourage our Electric Utilities to source, by a certain future date, a minimum percentage of the electricity delivered to customers from renewable energy generation facilities. At December 31, 2010, we were subject to the following renewable energy portfolio standards or objectives:

- South Dakota. South Dakota has adopted a renewable portfolio objective that encourages utilities to generate, or cause to be generated, at least 10% 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.

- 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) 5% for compliance years 2008-2009; (ii) 10% for compliance years 2010-2014; and (iii) 15% 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 ratepayers for contracts pre-approved by the MTPSC. We are currently in compliance with applicable standards.

- 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% of retail sales from 2011 to 2014 (ii) 20% of retail sales from 2015 to 2019; and (iii) 30% of retail sales by 2020. Of these amounts, 3% must be generated from renewable resources with one-half of the renewable 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% 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. Our current strategy is to incorporate renewable energy as required to comply with the standards.

Wyoming is also exploring the implementation of renewable energy portfolio 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.

In connection with the Aquila Transaction, the CPUC, NPSC, IUB and KCC approved orders or settlement agreements providing that, among other things, (i) our utilities in those jurisdictions cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40% of their total capitalization; and (ii) 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. In addition to the restrictions described above, each state in which we conduct utility operations imposes restrictions on affiliate transactions, including inter-company loans.

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 utility subsidiaries provide FERC-jurisdictional services subject to FERC's oversight.

Our Electric Utilities and our two of our non-regulated subsidiaries, Black Hills Wyoming and Enserco, 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, enforce 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.

The following summarizes our recent state and federal rate case and surcharge activity (dollars in millions):

	Type of Service	Date Requested	Date Effective	Amount Requested	Amount Approved	Return on Equity	Approved Capital Structure Equity	Approved Capital Structure Debt
Nebraska Gas (1)	Gas	12/2009	9/2010	$12.1	$8.3	10.1%	52.0%	48.0%
Iowa Gas	Gas	6/2008	7/2009	$13.6	$10.8	10.1%	51.4%	48.6%
Iowa Gas (2)	Gas	6/2010	2/2011	$4.7	$3.4	Global Settlement	Global Settlement	Global Settlement
Colorado Gas	Gas	6/2008	4/2009	$2.7	$1.4	10.3%	50.5%	49.5%
Kansas Gas	Gas	5/2009	10/2009	$0.5	$0.5	10.2%	50.7%	49.3%
Black Hills Power (3)	Electric	9/2008	1/2009	$4.5	$3.8	10.8%	57.0%	43.0%
Black Hills Power (4)	Electric	9/2009	4/2010	$32.0	$15.2	Global Settlement	Global Settlement	Global Settlement
Black Hills Power (5)	Electric	10/2009	6/2010	$3.8	$3.1	10.5%	52.0%	48.0%
Colorado Electric (6)	Electric	1/2010	8/2010	$22.9	$17.9	10.5%	52.0%	48.0%

(1) On December 1, 2009, Nebraska Gas filed with the NPSC a $12.1 million rate case requesting a gas revenue increase to recover operating costs and distribution system investments. The proposed increase in revenue was approximately 6.5%. Interim rates, subject to refund for the entire amount of the proposed increase, went into effect on March 1, 2010. On August 18, 2010, NPSC issued a decision approving an annual revenue increase of approximately $8.3 million, based on a return on equity of 10.1% with a capital structure of 52% equity effective September 1, 2010. A plan for refund has been approved by the NPSC. An appeal was filed by the OCA relating to the entire rate case decision. However, the NPSC denied this appeal. Subsequently, the OCA filed an appeal in September 2010 appealing a portion of the Commission's order addressing our affiliate transactions. The appeal is still outstanding.

(2) On June 8, 2010, Iowa Gas filed a request with the IUB for a $4.7 million revenue increase to recover the cost of capital investments made in our gas distribution system and other expense increases incurred since December 2008. Interim rates, subject to refund, equal to a $2.6 million increase in revenues went into effect on June 18, 2010. In August 2010, we reached a settlement with the OCA for a revenue increase of $3.4 million. This settlement agreement was modified and re-filed on January 11, 2011. The modified settlement excludes the integrity investment tracker and the three-year rate moratorium included in the original settlement agreement filed on September 1, 2010, which was not approved by the IUB. Approval from the IUB was received on February 10, 2011.

(3) On February 10, 2009, FERC approved a formulaic approach to the method used to determine the revenue component of Black Hills Power's open access transmission tariff, and increased the utility's annual transmission revenue requirement by approximately $3.8 million. The revenue requirement is based on an equity return of 10.8%, and a capital structure consisting of 57% equity and 43% debt. New annual rates went into effect on January 1, 2009.

(4) On September 30, 2009, Black Hills Power filed a rate case with the SDPUC requesting an electric revenue increase to recover costs associated with Wygen III and other generation, transmission and distribution assets and increased operating expenses incurred during the past four years. In March 2010, the SDPUC approved a $24.1 million increase in interim rates, subject to refund, effective April 1, 2010 for South Dakota customers. On July 7, 2010, the SDPUC approved a final revenue increase of $15.2 million and a base rate increase of $22.0 million with an effective date of April 1, 2010. The approved capital structure and return on equity are confidential. A refund was provided to customers in the third quarter of 2010.

As part of the settlement stipulation, Black Hills Power agreed: (1) to credit customers 65% of off-system sales margins with a minimum credit of $2.0 million per year; (2) that rates will include a South Dakota Surplus Energy Credit of $2.5 million in year one (fiscal year ending March 2011), $2.25 million in fiscal year two, $2.0 million in fiscal year three and zero thereafter; and (3) a moratorium until April 2013 for any base rate increase excluding any extraordinary events as defined in the stipulation agreement; while (4) the SDPUC agreed to adjust the off-system sales portion of the Fuel and Purchased Power Adjustment Clause for the methodology to directly assign renewable resources and firm purchases to the customer load

(5) On October 19, 2009, Black Hills Power filed a rate case with the WPSC requesting a $3.8 million electric revenue increase to recover costs associated with Wygen III and other generation, transmission and distribution assets and increased operating expenses incurred since 1995. On May 4, 2010, Black Hills Power filed a settlement stipulation agreement with the WPSC for a $3.1 million increase in annual revenues. On May 13, 2010, WPSC approved these new rates based on a return on equity of 10.5% with a capital structure of 52% equity and 48% debt. New rates went into effect on June 1, 2010.

(6) On January 6, 2010, Colorado Electric filed a rate case with CPUC requesting a $22.9 million electric revenue increase to recover increased operating expenses associated with electricity supply contracts, as well as recovery for investment in equipment and electricity distribution facilities necessary to maintain and strengthen the reliability of the electric delivery system in Colorado. On August 5, 2010, the CPUC approved a settlement agreement for $17.9 million in annual revenues with a return on equity of 10.5% and a capital structure of 52% equity and 48% debt. New rates were effective August 6, 2010.

Included in the rate case order was a provision that off-system sales margins be shared with customers commencing August 6, 2010. The percentage of margin to be shared with the customers was not resolved at the time of the rate case settlement. The CPUC has therefore required that the off-system sales margins earned beginning August 6, 2010 be deferred on the balance sheet until settlement of the sharing mechanism. Colorado Electric is preparing a proposal for a sharing mechanism to be filed with the CPUC.

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. The ultimate cost could be significantly different from the amounts estimated.

Environmental Expenditure Estimates	Total (in millions)
2011	$ 12.7
2012	3.8
2013	0.6
Total	$ 17.1

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. We are not aware of any proposed regulations that will have a significant impact on our operations. 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. Also, the EPA is scheduled to issue updated regulations for wastewater discharge for electric generating units late in 2011, which could have a significant impact on all of our generating fleet.

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, NOx, mercury particulate matter, and as of June 23, 2010, Greenhouse Gases. 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 that year. 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, 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 2040. 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 II and Wygen III. Those facilities are allowed to operate under their construction permit until the Title V permits are issued by the state. The Title V application for Wygen II was submitted in 2008, with the permit expected early in 2011. The Wygen III Title V application was submitted in January 2011, with the permit expected in late 2011. Both applications were filed in accordance with regulatory requirements.

On April 29, 2010, the EPA published proposed Industrial and Commercial Boiler regulations, which provide for hazardous air pollutant-related emission limits and monitoring requirements for both major and area sources of hazardous air pollutants. The final rule has a court ordered deadline of February 21, 2011 and we will evaluate once final. If issued as proposed, will have a significant impact on our Neil Simpson I, Osage, Ben French and W.N. Clark facilities. The regulation currently has a three year compliance window and will require engineering evaluations to determine economic viability of continued operations of these units. In our current opinion, the regulations as proposed on April 29, 2010 will lead to retirement of these units within three years of the effective date of the final rule.

The EPA is obligated under a court-approved consent decree to sign a proposed electric utility hazardous air pollutant rule (Utility MACT) by March 16, 2011 and sign its notice of final rule making by November 16, 2011. It is anticipated that affected units will have three years from the rule effective date to be in compliance. In 2010, we participated in the EPA's effort to gather data for rule development. Certain requirements of that regulation could have significant impacts on the Neil Simpson II, Wygen II, Wygen III and Wyodak plants.

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. 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 greenhouse gases, 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. It is anticipated this additional process will add several months to the permitting process.

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. This act has a significant impact on our W.N. Clark facility and on October 29, 2010, Colorado Electric filed testimony with the CPUC that included a proposal recommending retirement of the W.N. Clark facility within three years of promulgation of the EPA's proposed Industrial and Commercial Boiler Hazardous Air Pollutant Regulation, or in the absence of such regulation, to retire the units by the end of 2017. On December 15, 2010 the CPUC issued an order approving closure of the W.N. Clark plant by December 31, 2013. On January 7, 2011 the State Air Quality Control Commission adopted the CPUC order into the Colorado State Implementation Plan which, after legislative approval, will be a state regulation and will be submitted to EPA Region VIII for approval.

In June 2011, the EPA is scheduled to issue proposed Electric Utility New Source Performance Standards for greenhouse gases. As the regulations are not yet proposed we cannot ascertain their impacts but we anticipate they will be applicable to Wygen III. In 2011 it is anticipated the EPA will finalize a more stringent ozone ambient air standard. 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 would evaluate Neil Simpson II, Wygen II and Wygen III for further reductions in NO_x emissions.

Mercury regulations

Approximately 60% of our electric generating capacity is coal-fired. The EPA is scheduled to propose the Utility MACT rule by March 16, 2011 which will, among other pollutants, address mercury emissions at Neil Simpson II, Wygen II and Wygen III.

The effects of any new rules regarding mercury reduction cannot be determined at this time and may require us to make significant investments at our power generating facilities. The state air permit for Wygen II and Wygen III provides mercury emission limits and monitoring requirements with which we are in compliance. Wygen II has been utilized for 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. Federal multi-pollutant legislation is also being considered that would require reductions similar to the EPA rules and may add requirements for the reduction of GHG emissions.

Greenhouse Gas Regulations

We utilize a diversified energy portfolio of assets that includes wind sources and a fuel mix of coal and natural gas. Of these fuels, coal-fired power plants are the most significant sources of CO_2 emissions. Although we cannot predict specifically how, if or when, greenhouse gases will be regulated, any federally mandated GHG reductions or limits on CO_2 emissions could have a material impact on our financial position, results of operations, or cash flows. In 2011, we will be reporting 2010 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, greenhouse gas 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 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 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.

In connection with GHG initiatives, many states have enacted, and others are considering, renewable energy portfolio standards that require electric utilities to meet certain thresholds for the production or use of renewable energy. Colorado Electric is subject to renewable energy portfolio standards in Colorado. Black Hills Power is subject to mandatory renewable energy portfolio standards in Montana and voluntary standards in South Dakota. In the near future, we expect similar (if not more challenging) renewable energy portfolio standards to be mandated at the federal level or in other state jurisdictions in which we operate. Federal legislation for renewable energy portfolio standards is also under consideration. We anticipate significant additional costs to comply with any federally or state mandated renewable energy standards, which we would expect to pass on to our customers. However, 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.

Solid Waste Disposal

Various materials used at our facilities are subject to disposal regulations. Under appropriate 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 Wyodak, Neil Simpson I, Ben French, Neil Simpson II, Wygen II and Wygen III plants are deposited in mined areas at the WRDC coal mine. These disposal areas are located below some shallow water aquifers in the mine. In 2009, the State of Wyoming confirmed their 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. We have suspended operations at the Osage power plant as of October 1, 2010. It has an on-site ash impoundment that is near capacity. An application to close the impoundment was filed with the State of Wyoming on November 3, 2010 and any future ash disposal will be at the Wyodak coal mine. Our W.N. Clark plant 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. Agreements are in place that require PacifiCorp and MEAN to be responsible for any such costs related to the solid waste from their ownership interest in the Wyodak plant and Wygen I plant, respectively.

Additional unexpected material costs could also result in the future if any regulator 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 is currently expected to be mid-2011. However, if ash becomes subject to regulations as a hazardous waste, implementation requirements could have a material impact on our financial position or results of operations.

Past Operations

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 2010, we undertook a third party review to obtain an updated estimate of remedial costs. From that review, obligations are estimated at between $3.6 million and $6.8 million. The acquisition also 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.

We have received rate orders that enable us to recover environmental cleanup costs in certain jurisdictions. In other jurisdictions, there is regulatory precedent for recovery of these costs. We are also pursuing 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 natural gas and crude oil primarily in the Rocky Mountain region; produces and sells electric capacity and energy through ownership of a portfolio of generating plants; produces and stores coal; and engages in natural gas, crude oil, coal, power and environmental marketing. The Non-regulated Energy Group consists of four business segments for reporting purposes:

- Oil and Gas;
- Power Generation;
- Coal Mining; and
- Energy Marketing.

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 for sale into commodity markets. As of December 31, 2010, the principal assets of our Oil and Gas segment included: (i) operating interests in oil and natural gas properties, including properties in the San Juan Basin (primarily New Mexico, including holdings within the tribal lands of the Jicarilla Apache and Southern Ute Nations), the Powder River Basin (Wyoming) and the Piceance Basin (primarily in Colorado); (ii) non-operated interests in oil and natural gas properties including wells located in the Williston (Bakken Shale primarily in North Dakota), Wind River (Wyoming), Bearpaw Uplift (Montana), Arkoma (Oklahoma), Anadarko (Texas) and Sacramento (California) basins; and (iii) a 44.7% ownership interest in the Newcastle gas processing plant and associated gathering system located in Weston County, Wyoming. The plant, operated by Western Gas Partners, LP, is adjacent to our producing properties in that area, and BHEP's production accounts for 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 December 31, 2010, we had total reserves of approximately 131 Bcfe, of which natural gas comprised 73% and oil comprised 27% of total reserves. The majority of our reserves are located in select oil and natural gas producing basins in the Rocky Mountain region. Approximately 28% of our reserves are located in the San Juan Basin of northwestern New Mexico, primarily in the East Blanco Field of Rio Arriba County, 26% are located in the Powder River Basin of Wyoming, primarily in the Finn-Shurley Field of Weston and Niobrara counties and 25% are located in the Piceance Basin of western Colorado.

Delivery Commitments

None of our oil and gas production is sold under long-term product delivery commitments.

Summary Oil and Gas Reserve Data

The summary information presented concerning our estimated proved developed and undeveloped oil and gas reserves and the 10% discounted present value of estimated future net revenues is based on reports prepared by CG&A, an independent consulting and engineering firm located in Fort Worth, Texas. Reserves in 2010 and 2009 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. Estimates of economically recoverable reserves and future net revenues are based on a number of variables, which may differ from actual results. Our 2008 reserves were determined based on the previous guidelines utilizing the price on the last day of the reporting period. (Oil (in Mbbl) is multiplied by six to convert to MMcfe). 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.

The Company believes it maintains 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. The Company's 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 the Company's 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. The Company's 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 as well 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 the Company's technical personnel to review field performance and future development plans in order to further verify their validity. Following these reviews the reserve database, including updated cost, price and ownership data, is furnished to CG&A so that they can prepare their independent reserve estimates and final report. Access to the Company's 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 22 years of practical experience in petroleum engineering and over 20 years 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; 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 30 years of Exploration and Production industry experience as a geologist. He has over 20 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.

The following tables set forth summary information concerning our estimated proved developed and undeveloped reserves, by basin, as of December 31, 2010, 2009 and 2008:

Proved Reserves		December 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

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Proved Reserves		December 31, 2009				
	Total	Piceance	San Juan	Williston	Powder River	Other
Developed -						
Natural Gas (MMcf)	74,911	14,247	39,276	237	10,711	10,440
Oil (Mbbl)	4,274	—	7	162	4,068	37
Total Developed (MMcfe)	100,555	14,247	39,318	1,209	35,119	10,662
Undeveloped -						
Natural Gas (MMcf)	12,749	5,054	3,030	768	460	3,437
Oil (Mbbl)	1,000	—	—	516	484	—
Total Undeveloped (MMcfe)	18,749	5,054	3,030	3,864	3,364	3,437
Total MMcfe	119,304	19,301	42,348	5,073	38,483	14,099

Proved Reserves		December 31, 2008				
	Total	Piceance	San Juan	Williston	Powder River	Other
Developed -						
Natural Gas (MMcf)	88,701	18,194	48,168	303	10,303	11,733
Oil (Mbbl)	4,429	—	13	220	4,163	33
Total Developed (MMcfe)	115,275	18,194	48,246	1,623	35,281	11,931
Undeveloped -						
Natural Gas (MMcf)	65,731	36,728	16,090	508	421	11,984
Oil (Mbbl)	756	—	—	303	444	9
Total Undeveloped (MMcfe)	70,267	36,728	16,090	2,326	3,085	12,038
Total MMcfe	185,542	54,922	64,336	3,949	38,366	23,969

The following table summarizes quantities of proved developed and undeveloped reserves by basin, estimated using SEC-defined product prices, as of December 31, 2010, 2009 and 2008:

Oil	December 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	December 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

	December 31, 2010					
Total MMcfe	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	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

Oil	December 31, 2009					
(in Mbbl)	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	5,185	—	13	523	4,607	42
Production	(366)	—	(3)	(32)	(321)	(10)
Additions - acquisitions	—	—	—	—	—	—
Additions - extensions and discoveries	152	—	—	152	—	—
Revisions to previous estimates	303	—	(3)	35	266	5
Balance at end of year	5,274	—	7	678	4,552	37

Natural Gas	December 31, 2009					
(in Mbbl)	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	154,432	54,922	64,258	811	10,724	23,717
Production	(9,710)	(1,263)	(5,571)	—	(297)	(2,579)
Additions - acquisitions	—	—	—	—	—	—
Additions - extensions and discoveries	2,560	—	2,135	222	—	203
Revisions to previous estimates	(59,622)	(34,358)	(18,516)	(28)	744	(7,464)
Balance at end of year	87,660	19,301	42,306	1,005	11,171	13,877

	December 31, 2009					
Total MMcfe	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	185,542	54,922	64,336	3,949	38,366	23,969
Production	(11,906)	(1,263)	(5,589)	(192)	(2,223)	(2,639)
Additions - acquisitions	—	—	—	—	—	—
Additions - extensions and discoveries	3,472	—	2,135	1,134	—	203
Revisions to previous estimates	(57,804)	(34,358)	(18,534)	182	2,340	(7,434)
Balance at end of year	119,304	19,301	42,348	5,073	38,483	14,099

Oil	December 31, 2008					
(in Mbbl)	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	5,807	—	3	243	5,504	57
Production	(387)	—	(5)	(27)	(339)	(16)
Additions - acquisitions	2	—	—	—	—	2
Additions - extensions and discoveries	438	—	—	280	19	139
Revisions to previous estimates	(675)	—	15	27	(577)	(140)
Balance at end of year	5,185	—	13	523	4,607	42

Natural Gas	December 31, 2008					
(in MMcf)	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	172,964	64,887	77,770	386	13,201	16,720
Production	(10,704)	(980)	(6,448)	—	(347)	(2,929)
Additions - acquisitions	3,352	—	—	—	—	3,352
Additions - extensions and discoveries	4,037	218	—	438	135	3,246
Revisions to previous estimates	(15,217)	(9,203)	(7,064)	(13)	(2,265)	3,328
Balance at end of year	154,432	54,922	64,258	811	10,724	23,717

	December 31, 2008					
Total MMcfe	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	207,806	64,887	77,788	1,844	46,225	17,062
Production	(13,026)	(980)	(6,478)	(162)	(2,381)	(3,025)
Additions - acquisitions	3,364	—	—	—	—	3,364
Additions - extensions and discoveries	6,665	218	—	2,118	249	4,080
Revisions to previous estimates	(19,267)	(9,203)	(6,974)	149	(5,727)	2,488
Balance at end of year	185,542	54,922	64,336	3,949	38,366	23,969

Production Volumes

	December 31, 2010		
Location	Oil (in Bbl)	Natural Gas (Mcfe)	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

	December 31, 2009		
Location	Oil (in Bbl)	Natural Gas (Mcfe)	Total (Mcfe)
San Juan	2,547	5,570,741	5,586,023
Piceance	—	1,298,924	1,298,924
Powder River	320,752	818,709	2,743,221
Williston	32,311	—	193,866
All other properties	10,342	2,578,498	2,640,550
Total Volume	365,952	10,266,872	12,462,584

	December 31, 2008		
Location	Oil (in Bbl)	Natural Gas (Mcfe)	Total (Mcfe)
San Juan	5,095	6,447,964	6,478,534
Piceance	—	1,003,062	1,003,062
Powder River	338,797	829,949	2,862,731
Williston	26,754	—	160,524
All other properties	16,781	2,928,428	3,029,114
Total Volume	387,427	11,209,403	13,533,965

	December 31, 2010		December 31, 2009	
Proved developed reserves as a percentage of total proved reserves on an MMcfe basis	72	%	84	%
Proved undeveloped reserves as a percentage of total proved reserves on an MMcfe basis	28	%	16	%
Present value of estimated future net revenues, before tax (in thousands)	$196,554		$134,322	

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

	December 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

	December 31, 2009					
	Total	Piceance	San Juan	Williston	Powder River	Other
Gas per Mcf	$2.52	$1.57	$2.58	$4.84	$2.72	$3.82
Oil per Bbl	$53.59	$—	$52.31	$52.64	$53.77	$49.16

Drilling Activity

The following tables reflect the wells completed through our drilling activities for the last three years. In 2010, we participated in drilling 21 gross (9 net) development and exploratory wells, with a net well success rate of 100%. A development well is a well drilled within a proved area of a reservoir known to be productive. An exploratory well is a well drilled to find and/or produce oil or gas in an unproved area, to find a new reservoir in a previously productive field or to extend a known reservoir. Gross wells represent the total wells we participated in, regardless of our ownership interest, while net wells represent our fractional ownership interests within those wells.

Year ended December 31,	2010		2009		2008	
Net Development wells	Productive	Dry	Productive	Dry	Productive	Dry
Piceance	—	—	—	—	3.62	—
San Juan	5.60	—	3.00	—	6.70	1.00
Williston	0.67	—	0.04	—	0.31	0.14
Powder River	2.66	—	—	—	3.75	—
Other	—	—	4.37	1.04	10.17	2.18
Total net developed wells	8.93	—	7.41	1.04	24.55	3.32

Year ended December 31,	2010		2009		2008	
Net Exploratory wells	Productive	Dry	Productive	Dry	Productive	Dry
Piceance	—	—	0.91	—	—	—
San Juan	—	—	—	—	2.00	—
Williston	—	—	0.03	—	0.76	—
Powder River	—	—	—	0.50	0.75	—
Other	—	—	0.50	0.37	—	—
Total net exploratory wells	—	—	1.44	0.87	3.51	—

As of December 31, 2010, we were participating in the drilling of 6 gross (0.75 net) wells, which had been commenced but not yet completed.

Recompletion Activity

Recompletion activities for the years ended December 31, 2010, 2009 and 2008 were insignificant to our overall oil and gas operations.

Productive Wells

The following table summarizes our gross and net productive wells at December 31, 2010, 2009 and 2008:

	December 31, 2010					
	Total	Piceance	San Juan	Williston	Powder River	Other
Gross Productive:						
Oil	463	1	2	38	418	4
Natural Gas	828	88	225	—	7	508
Total	1,291	89	227	38	425	512
Net Productive:						
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

	December 31, 2009					
	Total	Piceance	San Juan	Williston	Powder River	Other
Gross Productive:						
Oil	454	1	2	29	416	6
Natural Gas	860	86	220	—	20	534
Total	1,314	87	222	29	436	540
Net Productive:						
Oil	314.47	—	1.91	2.51	309.40	0.65
Natural Gas	355.20	65.93	210.21	—	2.50	76.56
Total	669.67	65.93	212.12	2.51	311.90	77.21

	December 31, 2008					
	Total	Piceance	San Juan	Williston	Powder River	Other
Gross Productive:						
Oil	414	1	2	12	395	4
Natural Gas	682	74	158	—	7	443
Total	1,096	75	160	12	402	447
Net Productive:						
Oil	314.65	—	1.91	1.78	310.45	0.51
Natural Gas	287.20	55.00	152.11	—	0.87	79.22
Total	601.85	55.00	154.02	1.78	311.32	79.73

Acreage

The following table summarizes our undeveloped, developed and total acreage by location as of December 31, 2010:

	Undeveloped		Developed		Total	
	Gross	Net *	Gross	Net	Gross	Net
Piceance	40,881	31,347	35,497	31,460	76,378	62,807
San Juan	40,908	39,489	27,232	24,136	68,140	63,625
Williston	26,078	3,875	16,756	1,874	42,834	5,749
Powder River	54,113	38,074	27,389	17,110	81,502	55,184
Bearpaw Uplift (MT)	417,753	73,940	100,364	18,845	518,117	92,785
Other	68,735	45,420	30,200	5,988	98,935	51,408
Total	648,468	232,145	237,438	99,413	885,906	331,558

* Approximately 5.3% (43,135 gross and 12,232 net acres) and 4.3% (46,935 gross and 10,048 net acres) and 14.4% (122,688 gross and 33,473 net acres) of our net undeveloped acreage could expire in 2011, 2012 and 2013, respectively, if production is not established on the leases or further action is not taken to extend the associated lease terms. Decisions on extending leases are based on expected exploration or development potential under the prevailing economic conditions.

Competition. The oil and gas industry is highly competitive. We compete with a substantial number of companies ranging from those that have greater financial resources, personnel, facilities and in some cases technical expertise, to a multitude of smaller, aggressive new start-up companies. Many of these companies explore for, produce and market 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 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.

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 or operate wells, and establish rules regarding the location of wells, the method of drilling and casing wells, the surface use and restoration of properties on which wells are drilled, the timing of when drilling and construction activities can be conducted relative to various wildlife stipulations and the 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 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 oil and natural gas operations and administration of royalties on federal onshore and tribal lands. In addition, the Bureau of Indian Affairs and each Native American tribe promulgate and enforce additional regulations pertaining to oil and natural gas operations and administration of taxes on 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. For example, in 2008 new state regulations were implemented in New Mexico which increased the regulatory requirements associated with drilling pits. Colorado legislation in 2007 changed the structure of the oil and gas commission, which has subsequently developed and approved significant changes to oil and gas regulations which were implemented in 2009. Changes such as these 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. 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 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 treatment as RCRA wastes may in the future be designated as wastes under RCRA or other applicable statutes.

Greenhouse Gas Regulations. The Oil and Gas segment is impacted by regulation in the state of New Mexico where legislation was passed requiring the tracking and reporting of GHG emissions, beginning with calendar year 2008. The EPA published an amendment to its GHG reporting requirements in the November 30, 2010 Federal Register, adding Petroleum and Natural Gas Systems to the mandatory reporting requirements. Data gathering commenced on January 1, 2011, with the final report to the EPA due in 2012. Other states may implement their own such programs in the future.

Power Generation Segment

Our Power Generation segment, which operates through Black Hills Electric Generation and its subsidiaries, acquires, develops and operates our non-regulated power plants. As of December 31, 2010, we held varying interests in independent power plants operating in Wyoming and Idaho with a total net ownership of 120 MW. In January 2011, we sold our ownership interests in the Idaho partnerships which own the Idaho facilities.

During 2008, we sold seven IPP plants with 974 MW of capacity to affiliates of Hastings and IIF for a purchase price of $840 million, subject to customary adjustments. We completed the sale in July 2008 and received net cash proceeds of $756 million, including the effects of estimated working capital adjustments and other costs and net of the required payoff of $67.5 million of project debt. See Notes 1 and 22 to the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

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. We sell additional power into the wholesale power markets from our generating capacity when it is available and economical.

As of December 31, 2010, the power plant ownership interests held by our Power Generation segment included:

Power Plants[1]	Fuel Type	Location	Ownership Interest	Owned Capacity (MW)	Start Date
Gillette CT	Gas	Gillette, Wyoming	100.0%	40.0	2001
Wygen I[2]	Coal	Gillette, Wyoming	76.5%	68.9	2003
Glenns Ferry Cogeneration [3]	Gas	Glenns Ferry, Idaho	50.0%	5.5	1996
Rupert Cogeneration [3]	Gas	Rupert, Idaho	50.0%	5.5	1996

(1) We are currently constructing two 100 MW combined-cycle gas-fired power generation facilities in Colorado. These facilities are expected to be completed by December 31, 2011.

(2) In January 2009, we sold a 23.5% ownership interest in this plant to MEAN. See Note 22 of Notes to our Consolidated Financial Statements for further description of the transaction.

(3) On January 18, 2011, we sold our ownership interest in the partnerships which owns the Glenns Ferry and Rupert Cogeneration facilities.

Gillette CT. The Gillette CT is a simple-cycle, gas-fired combustion turbine located at our Gillette, Wyoming energy complex. The facility's energy and capacity is sold to Cheyenne Light under a 10-year power purchase agreement that expires in August 2011.

Wygen I. The Wygen I generation facility is a mine-mouth, coal-fired power plant with a total nameplate capacity of 90 MW located at our Gillette, Wyoming energy complex. We own 76.5% of the plant. We sell 60 MW of unit contingent capacity and energy from this plant to Cheyenne Light under a PPA that expires on December 31, 2022. The PPA includes an option for Cheyenne Light to purchase Black Hills Wyoming's ownership interest in the Wygen I facility between 2013 and 2019. The purchase price related to the option is $2.55 million per MW which is equivalent to the estimated initial per MW price of new construction of the Wygen III facility. This price is reduced annually by an amount of annual depreciation assuming a facility life of 35 years.

Idaho Cogeneration Facilities. Through partnership investments, at December 31, 2010, we owned a 50% interest in two QFs in Rupert and Glenns Ferry, Idaho. Rupert and Glenns Ferry are both 11 MW combined-cycle, gas-fired power plants. Our investments in the partnerships have been accounted for under the equity method of accounting. On January 18, 2011, we sold our ownership interests in the partnerships which own the Idaho facilities.

Black Hills Colorado IPP. During 2009, we began planning and purchasing equipment for the construction of two 100 MW combined-cycle gas-fired power generation facilities to fulfill a 20-year PPA signed with Colorado Electric. Construction of the facilities commenced in July 2010, and these facilities are expected to be completed by December 31, 2011.

Competition. The independent power industry is replete with strong and capable competitors, some of which may have more extensive operating experience, larger staffs 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. In addition, the deregulation efforts that caused some vertically integrated utilities to separate their generation, transmission, and distribution businesses have slowed considerably since the merchant energy crisis in 2001. Our Power Generation business could face greater competition if utilities are permitted to robustly invest in power generation assets. However, regulatory pressures for utilities to competitively bid generation resources may provide their own upside opportunity for independent power producers in some regions.

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

The Energy Policy Act of 1992. The passage of the Energy Policy Act of 1992 encouraged independent power production by providing certain exemptions from regulation for EWGs. EWGs are exclusively in the business of owning or operating, or both owning and operating, eligible power facilities and selling electric energy at wholesale. EWGs are subject to FERC regulation, including rate regulation. We own two EWGs: Wygen I and Gillette CT. 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 regulated Electric Utilities. Our Gillette CT and Wygen I facilities are subject to Titles IV and V of the Clean Air Act and have the required permits in place. 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 2040, without purchasing additional allowances. The EPA's pending Utility MACT described in the Utilities Group section will apply to Wygen I. The EPA's GHG Tailoring Rule described in the Utilities Group section will apply to the Gillette CT and Wygen I, upon a major modification or upon operating permit renewal.

Clean Water Act. The Clean Water Act impacts our Power Generation business in a manner similar to the impact described above for our regulated Electric Utilities. Each of our facilities 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 factors discussed under this caption for the Utilities Group also apply to our Power Generation segment.

Coal Mining Segment

Our Coal Mining segment operates through our WRDC subsidiary. We mine, process and sell low-sulfur coal at our coal mine near Gillette, Wyoming. The WRDC coal mine, which we acquired in 1956 from Homestake Gold Mining Company, is located in the Powder River Basin. The Powder River Basin contains one of the largest coal reserves in the United States. We produced approximately 5.9 million tons of coal in 2010. In a basin characterized by thick coal seams, our overburden ratio, a comparison of the cubic yards of dirt removed to a ton of coal uncovered, has in recent years trended towards a ratio of approximately 2.3:1, where it is expected to remain for the next several years.

Mining rights to the coal are based on four federal leases and one state lease. We pay federal and state royalties of 12.5% and 9.0%, respectively, of the selling price of all coal. As of December 31, 2010, we had coal reserves of approximately 261.9 million tons, based on internal engineering studies. The reserve life is equal to approximately 40 years at expected production levels.

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

- Our regulated electric utilities, Black Hills Power and Cheyenne Light;
- The 362 MW Wyodak power plant owned 80% by PacifiCorp and 20% by Black Hills Power;

- PacifiCorp for the Dave Johnston power plant located near Casper, Wyoming and served by rail;
- The 110 MW Wygen III power plant owned 52% by Black Hills Power, 25% by MDU and 23% by the City of Gillette;
- Our 90 MW non-regulated mine-mouth power plant, Wygen I owned 76.5% by Black Hills Wyoming and 23.5% by MEAN; and
- Certain regional industrial customers served by truck.

Our Coal Mining segment sells coal to Black Hills Power and Cheyenne Light for all of their requirements under agreements that limit earnings from these affiliate coal sales to a specified return on our coal mine's cost-depreciated investment base. The return is 4% (400 basis points) 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, which was placed into service in 1995. The agreement with Cheyenne Light provides coal for the life of the Wygen II plant, which was placed into service January 1, 2008.

We increased our coal production to supply additional mine-mouth power generating capacity related to the 110 MW Wygen III plant, which began commercial operations in April 2010. Coal supply agreements provide WRDC will supply the coal to Wygen III through June 1, 2060 under an agreement that limits earnings from these affiliate coal sales to a specified return on our coal mines' cost-depreciated investment base. The return is 4% (400 basis points) above A-rated utility bonds, to be applied to our coal mining investment base as determined each year.

The price for unprocessed coal sold to PacifiCorp for its 80% interest in the Wyodak plant is determined by a coal supply agreement which terminates in 2022. The price for coal sold to PacifiCorp for its Dave Johnston plant is determined by a coal supply agreement which terminates in December 2011.

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 our off-site sales have been to consumers within a close proximity to our mine. There are limitations on our ability to economically transport our lower-heat content coal, but we are reviewing new opportunities to market our coal.

Environmental Regulation. The construction and operation of coal mines are subject to extensive 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, and regularly do attend to issues arising due to the proximity of the mine disturbance boundary to the City of Gillette and to related residential and industrial development. The impacts from mining are routinely viewed negatively by the general public and increasing complaints and challenges to the permits may occur as mining operations move closer to the development areas. Specific concerns 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 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 on November 19, 2010, and a final rule is expected in late 2011 or early 2012. 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, implementation requirements could have a material impact on our financial position and results of operations.

Mine Reclamation. 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 April 2011 and an application for renewal has been timely filed. Based on extensive reclamation studies, we have accrued approximately $17.6 million for reclamation costs as of December 31, 2010. If additional requirements or changes to current requirements are imposed in the future, we may experience a material increase in reclamation costs. The mining operation must also meet specific environmental performance standards regulated by the WDEQ through permit commitments and statutes. Failure to achieve these standards could potentially delay the release of the bonds and/or result in increased mitigation costs.

Energy Marketing Segment

Through our subsidiary, Enserco, we engage in natural gas, crude oil, coal, power and environmental marketing and trading in the United States and Canada. Our marketing operations are headquartered in Denver, Colorado, with a satellite sales office in Calgary, Alberta, Canada.

Our energy marketing business seeks to provide services to producers and end-users of natural gas, crude oil, coal, power and environmental products and to capitalize on market volatility by employing certain risk-managed commodity trading strategies. The diversity of the commodities portfolio that we market helps us optimize value for shareholders. The service provider focus of our energy marketing activities largely differentiates us from other energy marketers. Through our producer services group, we assist mostly small- to medium-sized independent producers throughout the Western United States with marketing and transporting their crude oil and natural gas. Through our origination services, we work with utilities, municipalities and industrial users of natural gas to provide customized delivery services, as well as to support their efforts to optimize their transportation and storage positions. Our coal marketing team assists small utility and industrial coal consumers manage their coal procurement and transportation functions. Similarly, our power marketing experts help both buyers and sellers of electricity, as well as assisting customers with the monetization of emissions or other environmental products.

Our natural gas marketing focuses primarily on producer services and wholesale marketing. It includes the purchase, sale, storage and transportation of natural gas, as well as a variety of services including asset optimization, price risk management and customized offerings to producer and end-use clients. Producer services margins are typically fee-based, limited risk, recurrent transactions with long-term customers. Additionally, the producer services division has captured increased opportunities for growth with the recent shale natural gas discoveries. The team's wholesale efforts are focused in the Rocky Mountain, Western and Mid-Continent regions of the United States, the entirety of Canada, and expanding into the eastern United States.

Our crude oil marketing focuses on providing optimization services to both producers and end-use markets in the Rocky Mountain States with an emphasis in the Bakken Shale of North Dakota. With exclusive trucking arrangements and access to all major Rockies pipelines, Enserco extends to its customers the benefit of established relationships with premium markets and transportation options via pipeline, truck and rail. Enserco is continuing to build out its truck unloading stations and currently has six strategically located stations in North Dakota, Wyoming and Colorado as well as crude oil storage in Wyoming. Enserco's crude oil marketing team provides us with a low risk, recurring margin stream.

Enserco began marketing coal in June 2010 with the acquisition of a coal marketing business. Our coal marketing team currently participates in financial and physical coal markets, primarily focused in coal basins west of the Mississippi River. Our presence spans the physical coal supply chain from sourcing, storage and delivery. We leverage extensive experience and partnering arrangements to meet the challenges facing the physical markets. Further, we maintain long-term supply positions from multiple sources in multiple basins, including Wyoming's Powder River and Uinta Basins that allow us to perform beyond the role of a traditional merchant participant and closer to a primary supplier via supply sourcing flexibility and security.

Enserco began power and environmental marketing late in the third quarter of 2010. FERC approval was received for power marketing in December 2010 with an effective date of September 1, 2010. The power marketing focuses on origination and customer business with an emphasis on a diversified portfolio of short, mid- and long-term transactions. The marketing effort primarily involves execution of financial transactions, at liquid trading hubs in day-ahead markets. The geographic scope encompasses the United States.

Environmental marketing focuses on producer services and customized solutions for all aspects of the renewable business. This strategy encompasses short, mid- and longer term origination efforts with end users. Our marketers monetize Renewable Energy Credits, carbon and other emissions as well as optimize renewable assets including solar, wind and biomass. The focus is on opportunities within the United States, both in mandatory and elective markets.

Our average daily marketing physical volumes for the year ended December 31, 2010 were approximately 1.6 million MMBtu of gas, approximately 18,455 Bbls of oil and approximately 33,250 tons of coal.

Our total gross margin recognized for each of the following years was derived from our marketing strategies according to the following (in millions):

	2010		
	Realized Gain (Loss)	Unrealized Gain (Loss)	Total Gain (Loss)
Natural Gas Wholesale trading (storage)	$20.6	$0.2	$20.8
Natural Gas Wholesale trading (transportation)	5.5	(7.9)	(2.4)
Producer services (natural gas)	3.8	(0.5)	3.3
Producer services (crude oil)	8.9	1.6	10.5
Coal marketing *	1.6	2.0	3.6
Power marketing *	(2.5)	(1.4)	(3.9)
Environmental marketing *	—	—	—
	37.9	(6.0)	31.9
Wholesale trading (proprietary and other)	(5.4)	1.5	(3.9)
Total gross margin	$32.5	$(4.5)	$28.0

* Includes coal marketing commencing in June 2010 and power and environmental marketing commencing in the third quarter of 2010.

	2009		
	Realized Gain (Loss)	Unrealized Gain (Loss)	Total Gain (Loss)
Natural Gas Wholesale trading (storage)	$2.2	$(1.7)	$0.5
Natural Gas Wholesale trading (transportation)	10.9	5.5	16.4
Producer services (natural gas)	4.3	0.4	4.7
Producer services (crude oil)	11.3	(8.2)	3.1
	28.7	(4.0)	24.7
Wholesale trading (proprietary and other)	12.7	(24.0)	(11.3)
Total gross margin	$41.4	$(28.0)	$13.4

	2008		
	Realized Gain (Loss)	Unrealized Gain (Loss)	Total Gain (Loss)
Natural Gas Wholesale trading (storage)	$6.6	$4.0	$10.6
Natural Gas Wholesale trading (transportation)	13.7	4.1	17.8
Producer services (natural gas)	6.0	(0.2)	5.8
Producer services (crude oil)	1.0	6.6	7.6
	27.3	14.5	41.8
Wholesale trading (proprietary and other)	(7.7)	25.2	17.5
Total gross margin	$19.6	$39.7	$59.3

The tables below summarize our realized and unrealized gross margins by product and strategy. Producer Services and Other Recurrent are marketing strategies that are typically fee-based, limited risk, recurrent transactions with long-term customers.
Asset based strategies are marketing strategies that involve trading around assets, commonly of the storage and transportation variety. These strategies typically have limited and quantifiable downside and higher upside potential.

	2010					
	Natural Gas	Crude Oil	Coal *	Power *	Environmental *	Total
Realized -						
Producer Services and Other Recurrent	$3.8	$5.7	$1.1	$—	$—	$10.6
Asset Based	23.8	3.2	—	—	—	27.0
Proprietary and Other	(3.0)	—	0.4	(2.5)	—	(5.1)
Total realized	24.6	8.9	1.5	(2.5)	—	32.5
Unrealized -						
Producer Services and Other Recurrent	(0.5)	2.9	1.4	—	—	3.8
Asset Based	(7.7)	(1.3)	—	—	—	(9.0)
Proprietary and Other	1.4	0.1	0.6	(1.4)	—	0.7
Total unrealized	(6.8)	1.7	2.0	(1.4)	—	(4.5)
Total -						
Producer Services and Other Recurrent	3.3	8.6	2.5	—	—	14.4
Asset Based	16.1	1.9	—	—	—	18.0
Proprietary and Other	(1.6)	0.1	1.0	(3.9)	—	(4.4)
Total	$17.8	$10.6	$3.5	$(3.9)	$—	$28.0

* Includes coal marketing commencing in June 2010 and power and environmental marketing commencing in the third quarter of 2010.

	2009		
	Natural Gas	Crude Oil	Total
Realized -			
Producer Services and Other Recurrent	$4.3	$8.4	$12.7
Asset Based	13.2	2.9	16.1
Proprietary and Other	12.6	—	12.6
Total realized	30.1	11.3	41.4
Unrealized -			
Producer Services and Other Recurrent	0.4	(6.8)	(6.4)
Asset Based	3.8	(1.5)	2.3
Proprietary and Other	(23.9)	—	(23.9)
Total unrealized	(19.7)	(8.3)	(28.0)
Total -			
Producer Services and Other Recurrent	4.7	1.6	6.3
Asset Based	17.0	1.4	18.4
Proprietary and Other	(11.3)	—	(11.3)
Total	$10.4	$3.0	$13.4

	2008		
	Natural Gas	Crude Oil	Total
Realized -			
Producer Services and Other Recurrent	$6.0	$3.1	$9.1
Asset Based	20.3	(2.1)	18.2
Proprietary and Other	(7.7)	—	(7.7)
Total realized	18.6	1.0	19.6
Unrealized -			
Producer Services and Other Recurrent	(0.2)	4.4	4.2
Asset Based	8.1	2.2	10.3
Proprietary and Other	25.2	—	25.2
Total unrealized	33.1	6.6	39.7
Total -			
Producer Services and Other Recurrent	5.8	7.5	13.3
Asset Based	28.4	0.1	28.5
Proprietary and Other	17.5	—	17.5
Total	$51.7	$7.6	$59.3

We have various long-term natural gas transportation and storage positions in our marketing portfolio that enhance our potential for long-term earnings growth by providing upside potential and definable downside risk. Of these contractual positions, 62% include a right-of-first-refusal provision that provides us the opportunity to extend or renew favorable positions as their terms expire.

The total volumes of transportation capacity rights we held by region at December 31, 2010 were as follows:

Region	Term Until Expiration Less than 2 Years (2011 and 2012)	2 to 4 Years (2013 - 2016)	Greater than 4 Years (2017 and beyond)	Total Volume
		(Bcf of natural gas)		
Rockies	46.59	47.67	3.49	97.75
West	89.24	9.00	8.63	106.87
MidContinent	7.86	—	—	7.86
Total Capacity	143.69	56.67	12.12	212.48

The firm storage capacity rights we held by region at December 31, 2010 included:

Region	Volume (Bcf)	Term	
MidContinent/Upper Midwest	1.0	1/11-3/17	
MidContinent/Upper Midwest	1.0	1/11-3/12	*
MidContinent/Upper Midwest	1.0	1/11-3/13	*
MidContinent/Upper Midwest	1.0	1/11-3/12	
MidContinent/Upper Midwest	0.3	1/11-3/13	
West/Northwest	1.0	1/11-3/12	

* Indicates right-of-first-refusal to extend the capacity right following the expiration of the current term.

The following table summarizes the gas, oil and coal inventory at our Energy Marketing segment at December 31. In most cases, these commodities are being held in inventory to capture the price differential between the time purchased and a subsequent sales date in the future. In some cases, volumes are held to meet operational requirements. A high percentage of the inventory has been sold forward or hedged forward to lock in a margin upon future withdrawal.

	2010	2009
Gas inventory volumes (MMBtu)	14,922,353	12,177,802
Crude inventory volumes (Bbl)	198,052	69,045
Coal inventory volumes (Ton)	1,529	—

Competition. The energy marketing industry is characterized by numerous large competitors, some of which may have more extensive operating experience, larger staffs or greater financial resources than we possess.

Seasonality. Weather conditions affect the demand for natural gas and can create volatility in natural gas prices. The impact of these conditions typically occurs in the fourth and first quarters of our fiscal year, resulting in higher margin opportunities. Due to these seasonal fluctuations in demand and prices, results of operations on a quarterly basis may not reflect results which may be realized on an annual basis.

Working Capital Practices. The natural gas storage component of the business requires significant working capital investment in the form of inventory. Those investment levels vary as market opportunities change but have historically been higher in the second and third quarters of our fiscal year.

Regulation. Enserco is subject to the jurisdiction of the FERC, FTC and CFTC with respect to its marketing activities. With respect to its import and export of commodities, Enserco is also subject to the jurisdiction of the US Department of Energy, the US Department of Commerce, Canada's National Energy Board, and Alberta's Energy Resources Conservation Board, as well as US and Canadian Customs.

Other Properties

We own an eight-story, 67,000 square foot office building in Rapid City, South Dakota, where our corporate headquarters is located. Also in Rapid City, we own an office building consisting of approximately 36,000 square feet, and a warehouse building and shop with approximately 30,410 square feet. Our Gas Utilities own various office, service center and warehouse space totaling over 170,000 square feet throughout their service territories in Nebraska, Iowa, Colorado and Kansas. In Cheyenne, Wyoming, we own a business office with approximately 13,400 square feet, and a service center and garage with an aggregate of approximately 28,300 square feet. We also own other offices and warehouses located within our service areas.

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

- Approximately 8,800 square feet for an operations and customer call center in Rapid City, South Dakota;
- Approximately 62,160 square feet of office space in Omaha, Nebraska;
- Approximately 37,600 square feet for a customer call center in Lincoln, Nebraska;
- Approximately 47,430 square feet of office space in Denver, Colorado; 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.

We are currently constructing an office building in Papillion, Nebraska totaling approximately 36,000 square feet which is expected to be completed in May 2011.

Employees

At December 31, 2010, we had 2,124 full-time employees. Approximately 33% of the Company's employees are represented by a collective bargaining agreement. Out of a total of six collective bargaining agreements, three of these agreements are either currently in negotiations or planned for renewal negotiations during the first quarter of 2011. We have experienced no labor stoppages in recent years. At December 31, 2010, approximately 22% 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	367
Utilities	1,505
Non-regulated Energy	252
Total	2,124

At December 31, 2010, 705 employees (all within the Utilities Group), were covered by the following collective bargaining agreements:

Utility	Number of Employees	Union Affiliation	Expiration Date of Collective Bargaining Agreement
Black Hills Power	174	IBEW Local 1250	March 31, 2012
Cheyenne Light	56	IBEW Local 111	June 30, 2011
Colorado Electric	147	IBEW Local 667	April 15, 2011
Iowa Gas	139	IBEW Local 204	April 27, 2010
Kansas Gas	24	Communications Workers of America, AFL-CIO Local 6407	December 31, 2011
Nebraska Gas	165	IBEW Local 244	December 31, 2009
Total	705		

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 from those discussed in our forward-looking statements.

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 are, therefore, not recoverable.

Our regulated electric and gas utility operations are subject to cost-of-service regulation and earnings oversight from federal and state utility commissions. This regulatory treatment does not provide any assurance as to achievement of desired earnings levels. Our retail electric and gas utility rates are regulated on a state-by-state basis by the relevant state regulatory authorities based on an analysis of our costs, as reviewed and approved in a regulatory proceeding. The rates that we are allowed to charge may or may not match our related costs and allowed return on invested capital at any given time. While rate regulation is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that the state public utility commissions will judge all of our costs, including our 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 in South Dakota, Wyoming, Colorado, Montana, Nebraska, Iowa and Kansas are permitted to recover certain costs (such as increased fuel and purchased power costs, as applicable) 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 negatively affect our revenues, cash flows and results of operations.

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 taxes associated with the IPP Transaction and the Aquila Transaction. We had previously deferred approximately $185 million in taxes associated with the IPP Transaction and the Aquila Transaction, and in the third quarter of 2010, we reached an agreement with the Appeals Division of the IRS that resulted in a decrease in the amount of such deferral from $185 million to $125 million. The decrease represents the downward adjustment to tax depreciation allowed on certain assets sold, which resulted in a decrease to the gain realized on the sale of those assets and ultimately a decrease in deferred taxes. The remaining $125 million in deferred taxes relating to the IPP Transaction and the Aquila Transaction continues to be subject to IRS review.

We cannot be certain that the IRS will accept our tax positions. If the IRS successfully sought to assert contrary tax positions, we could be required to pay a significant amount of these deferred taxes earlier than currently forecasted. 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.

We could incur additional and substantial write-downs of the carrying value of our natural gas and oil properties, which would adversely impact our earnings.

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 (adjusted for cash flow hedges) 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 oil reserve levels and SEC-defined oil and gas prices, both of which impact the present value of estimated future net revenues. Revisions to estimates of natural gas and 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 non-cash impairment charges in the first quarter of 2009 and fourth quarter of 2008 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 2009 and 2008 impairments. See Note 12 to the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

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.

There are many uncertainties inherent in estimating quantities of proved reserves and their values. The process of estimating 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 oil and natural gas. Actual prices, production, development expenditures, operating expenses and quantities of recoverable 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 oil and natural gas prices after the date of the estimate may result in substantial upward or downward revisions.

Estimates of the quality and quantity of our coal reserves may change materially due to numerous uncertainties inherent in three dimensional structural modeling.

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 and judgment of known data, assumptions used regarding structural limits and mining extents, 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.

Municipal governments may seek to limit or deny franchise privileges.

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 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.

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;
- Our inability to obtain financing on acceptable terms, or at all;
- The possibility that one or more 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;
- Lower than anticipated increases in the demand for utility services in our target markets;
- 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 and our coal-fired generation capacity;
- Fuel prices or fuel supply constraints;
- Pipeline capacity and transmission constraints; and
- Competition.

We can provide no assurance that results from any acquisition will conform to our expectations. There may be additional risks associated with the operation of any newly acquired assets.

Acquisitions are subject to a number of uncertainties, many of which are beyond our control. Factors which may cause our actual results to differ materially from expected results include:

- Delay in, and restrictions imposed as part of, any required governmental or regulatory approvals;
- The loss of management or other key personnel;
- The diversion of our management's attention from other business segments; and
- Integration and operational issues.

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

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;
- Capital and operating costs to comply with increasingly stringent environmental laws and regulations;
- Opposition by members of public or special-interest groups;
- Weather interferences;
- 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 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.

Our 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.

Because prices for some of our products and services and operating costs for our business are volatile, our revenues and expenses may fluctuate.

A substantial portion of our net income in recent years was attributable to sales of contract and off-system wholesale electricity and natural gas into a robust market. 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 oil and gas operations is affected by the prevailing market prices of oil and natural gas. Oil and natural gas prices and markets historically have also been, and are likely to continue to be, volatile. A decrease in 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. Oil and natural gas prices are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty, and a variety of additional factors that are beyond our control. A decline in oil and natural gas price volatility could also affect our revenues and returns from Energy Marketing, which historically tend to increase when markets are volatile.

Our mining operation requires a reliable supply of replacement parts, explosives, fuel, tires and steel-related products. If the cost of any of these increase significantly, or if a source of these supplies or mining equipment was 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 some items generally increased to several months and prices for these items increased significantly.

Our hedging activities that are designed to protect against commodity price and financial market risks may cause fluctuations in reported financial results.

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.

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 on exchanges and 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 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. Dodd-Frank requires the CFTC to promulgate rules to define these terms, however we do not yet know the rules that the CFTC will actually promulgate or whether the rules or exceptions thereto will apply to us.

We use crude oil and natural gas derivative instruments in conjunction with our Energy Marketing activities and to hedge the sales price for a portion of our expected oil and gas production. We also use interest rate derivative instruments to minimize the impact of interest rate fluctuations. Depending on the regulations adopted by the CFTC, we could be required to post additional collateral with our dealer counterparties for our commitments and interest rate derivative transactions. 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 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 and foreign exchange rates by using derivative financial instruments and other hedging mechanisms, and by the activities we conduct in our trading operations. To the extent that we hedge our commodity price and interest rate exposures, we forego 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 and trading 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.

Our Energy Marketing and Utility operations rely on storage and transportation assets owned by third parties to satisfy their obligations.

Our energy marketing operations involve contracts to buy and sell natural gas, crude oil, coal and other commodities, many of which are settled by physical delivery. We depend on pipelines and other storage and transportation facilities owned by third parties to satisfy our delivery obligations under these contracts. Our Gas Utilities also rely on pipeline companies and other owners of gas storage facilities to deliver natural gas to ratepayers 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.

We may be adversely affected if we fail to achieve or maintain compliance with existing or future governmental regulations or requirements, or by the potentially high cost of complying with such requirements or addressing environmental liabilities.

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.

Our energy marketing segment may be subject to increased regulation.

In January 2010, the CFTC proposed regulations aimed at establishing speculative position limits on energy commodities. The proposed regulations would apply to all CFTC-regulated exchanges and would cap the number of contracts a market participant can hold at the NYMEX or Intercontinental Exchange. The position limit would restrict the amount of contracts a market participant can hold at any one time. This proposal is intended to curb excessive speculation in the energy markets and is part of a wider push to overhaul the financial markets. Due to uncertainty as to the final outcome of any rulemaking or legislation, we cannot definitively estimate the effect of increased regulation on our results of operations, cash flows or financial position.

Our financial performance depends on the successful operations of our facilities.

Operating electric generating facilities, 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 Gas Utilities purchase fuel from a number of suppliers. Our results of operations could be negatively impacted by disruptions in the delivery of fuel due to various factors, including but not limited to, transportation delays, labor relations, weather, and environmental regulations which could limit the Gas Utilities' ability to operate their facilities.
- Breakdown or failure of equipment or processes.
- Inability to recruit and retain skilled technical labor.
-

Labor relations. Approximately 33% of our employees are represented by a total of six collective bargaining agreements. We are currently in contract renewal negotiations on two of these agreements. Three separate arbitration proceedings have been initiated by the respective union locals concerning changes we made to our pension plans.

- 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.

We may be vulnerable to cyber attacks and terrorism.

Man-made problems such as computer viruses, terrorism, theft and sabotage, may disrupt our operations and harm our operating results. We operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. Our technology systems may be vulnerable to disability, failures or unauthorized access due to hacking, viruses, acts of war or terrorism and other causes. If our technology systems were to fail or be breached and we were unable to recover in a timely manner, we may 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 results of operations, financial condition and cash flows. In addition, our generation plants, fuel storage facilities, transmission and distribution facilities may be targets of terrorist activities that could disrupt our ability to produce or distribute some portion of our energy products.

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. We recently completed another fossil-fuel generating plant in Wyoming and are constructing others in 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 or 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 April 29, 2010, the EPA published proposed Industrial and Commercial Boiler regulations, which provide for hazardous air pollutant-related emission limits and monitoring requirements for both major and area sources of hazardous air pollutants. The final rule has a court-ordered deadline of February 21, 2011 and we will evaluate once final. If issued as proposed, will have significant impact at our Neil Simpson I, Osage, Ben French and W.N. Clark facilities. The regulation currently has a three year compliance window and will require an engineering evaluation to determine economic viability of continued operations at these units. We currently expect that, the adoption of these regulations will lead to retirement of these units within three years of the effective date of the final rule.
The EPA is obligated under a court-approved consent decree to sign a proposed electric utility hazardous air pollutant rule (Utility MACT rule) by March 16, 2011 and sign its notice of final rulemaking by November 16, 2011. We expect that affected units will have three years from effective date to be in compliance with the new rules. In 2010, we participated in the EPA's efforts to gather data for rule development. Certain requirements of that regulation could have significant impacts on the Neil Simpson II, Wygen I, Wygen II, Wygen III and Wyodak facilities.
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. 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.
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 low emitting resources. This act has a significant impact on our W.N. Clark facility and on October 29, 2010, Colorado Electric filed testimony with the CPUC that recommended retirement of the W.N. Clark facility to comply with House Bill 1365 within three years of promulgation of the EPA's proposed Industrial and Commercial Boiler Hazardous Air Pollutant Regulations, or in the absence of such regulation, to retire the units by the end of 2017. On December 16, 2010, the CPUC issued an order approving the closure of the W.N. Clark generation facility by December 31, 2013, and granted a presumption of need for replacement of the plant. Colorado Electric proposed to construct a third 92 MW General Electric LMS100 natural gas-fired turbine at its Pueblo Airport Generation Station. Colorado Electric will file a Certificate of Public Convenience and Necessity in the first quarter of 2011 that will provide additional justification for the incremental 50 MW generation capacity.

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 regulation on our results of operations, cash flows or financial position. The impact of GHG legislation or regulation upon 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 also be affected by 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 our 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. Governmental authorities may assess penalties on us if it is determined that we have not complied with environmental laws and regulations.

If we fail to comply with environmental laws and regulations, even if caused by factors beyond our control, that failure may result in the assessment of civil or criminal penalties and fines against us. Recent lawsuits by the EPA and various states filed against others within industries in which we operate, including enforcement actions under the EPA's New Source Review rule, highlight the environmental risks faced by generating facilities, in general, and coal-fired generating facilities in particular.

The characteristics of coal may make it difficult for coal users to comply with various environmental standards related to coal combustion or utilization. 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. Stricter 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. Stricter 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 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.

Our energy production, transmission and distribution activities involve numerous risks that may result in accidents and other operating risks and costs.

Inherent in our natural gas 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 affect 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 great.

Increased risks of regulatory penalties could negatively impact our business.

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 Energy Policy Act of 2005 increased FERC's civil penalty authority for violation of FERC statutes, rules and orders. FERC may now impose penalties of $1.0 million per violation, per day. The CFTC, EPA, OSHA and MSHA also impose 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 or our financial results.

Ongoing changes in the United States electric utility industry, including state and federal regulatory changes, a potential increase in the number or geographic scale of our competitors or the imposition of price limitations to address market volatility, could adversely affect our profitability.

The United States electric utility industry is experiencing increasing competitive pressures as a result of:

- Energy Policy Act of 2005 and the repeal of the PUHCA;
- Industry consolidation;
- Consumer demands;
- Transmission constraints;
- Renewable resource supply requirements;
- Resistance to the siting of utility infrastructure or to the granting of right-of-ways;
- Technological advances; and
- Greater availability of natural gas-fired power generation, and other factors.

FERC has implemented and continues to propose regulatory changes to increase access to the nationwide transmission grid by utility and non-utility purchasers and sellers of electricity. Industry deregulation in some states led to the disaggregation of vertically integrated utilities into separate generation, transmission and distribution businesses. Deregulation initiatives in a number of states may encourage further disaggregation. As a result, significant additional competitors could become active in the generation, transmission and distribution segments of our industry, which could adversely affect our financial condition or results of operations.

In addition, the independent system operators who oversee many of the wholesale power markets have in the past imposed, and may in the future continue to impose, price limitations and other mechanisms to address some of the volatility in these markets. These price limitations and other mechanisms may adversely affect the profitability of generating facilities that sell energy into the wholesale power markets. Given the extreme volatility and lack of meaningful long-term price history in some of these markets, and the imposition of price limitations by independent system operators, we may not be able to operate profitably in all wholesale power markets.

The recent global financial crisis made the credit markets less accessible and created a shortage of available credit. Should a similar financial crisis occur in the future, we may be unable to obtain the financing needed to refinance debt, fund planned capital expenditures or otherwise execute our operating strategy.

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

In addition, 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.

The global financial crisis has affected our counterparty credit risk.

As a consequence of the global financial crisis, the creditworthiness of many of our contractual counterparties (particularly financial institutions) has deteriorated.

We have established guidelines, controls and limits to manage and mitigate credit risk. For our energy marketing, production and generation activities, we seek to mitigate our credit risk by conducting a majority of our business with investment grade companies, setting tenor and credit limits commensurate with counterparty financial strength, obtaining netting agreements and securing our credit exposure with less creditworthy counterparties through parent company guarantees, prepayments, letters of credit and other security agreements. Although we aggressively monitor and evaluate changes in our counterparties' credit quality and adjust the credit limits based upon such changes, our credit guidelines, controls and limits may not fully protect us from increasing counterparty credit risk. To the extent the economic conditions causes our credit exposure to contractual counterparties to increase materially, such increased exposure could have a material adverse effect on our results of operations, cash flows and financial condition.

National and regional economic conditions may cause increased late payments and uncollectible accounts, which would reduce earnings and cash flows.

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 (including marketing counterparties). If late payments and uncollectible accounts increase, earnings and cash flows from our continuing operations may be reduced.

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" (stable outlook) by Moody's; "BBB-" (stable outlook) by S&P; and "BBB" (stable outlook) by Fitch. Reduction of our credit ratings could impair our ability to refinance or repay our existing debt and to complete new financings on 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.

We rely on cash distributions from our subsidiaries to make and maintain dividends and debt payments. Our subsidiaries may not be able or permitted to make dividend payments or loan funds to us.

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.

Our utility operations are regulated by state utility commissions in Colorado, Iowa, Kansas, Nebraska, Wyoming, South Dakota and Montana. In connection with the Aquila Transaction, the settlement agreements or acquisition orders approved by the CPUC, IUB, KCC and NPSC provide that, among other things, (i) our utilities in those jurisdictions cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40% of their total capitalization; and (ii) neither Black Hills Utility Holdings nor any of its utility subsidiaries can extend credit to us except in the ordinary course of business and upon reasonable terms consistent with market terms. In addition to the restrictions described above, each state in which we conduct utility operations imposes restrictions on affiliate transactions, including intercompany loans. If our utility subsidiaries are unable to pay dividends or advance funds to us as a result of these conditions, or if the ability of our utility subsidiaries to make dividends or advance funds to us is further restricted, it could materially and adversely affect our ability to meet our financial obligations or pay dividends to our shareholders.

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 in Item 7 of this Annual Report on Form 10-K for further information regarding these restrictions and their impact on our liquidity.

Increasing costs associated with our defined benefit retirement plans may adversely affect our results of operations, financial position or liquidity.

We have multiple defined benefit pension and non-pension postretirement plans that cover certain employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements 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.

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 became effective during our open enrollment period (November 1, 2010) while other provisions of the 2010 Acts will be effective in future years. Although the constitutional validity of the 2010 Acts is the subject of numerous lawsuits now pending in the federal courts, the outcome of which is uncertain, the 2010 Acts could require, among other things, changes to our current employee benefit plans and in our administrative and accounting processes. 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, and as the results of pending litigation become final.

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.

We have recorded a substantial amount of goodwill associated with the Aquila Transaction. 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 $354.8 million of goodwill on our consolidated balance sheet as of December 31, 2010. 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 these businesses, we may be forced to record a non-cash impairment charge, which would reduce our reported assets and net income. 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, 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.

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 (UNDER PROPOSED RULES)

Information concerning mine safety violations or other regulatory matters required by Sections 1503(a) of Dodd-Frank is included in Exhibit 99.1 of this Annual Report.

PART II

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

Our common stock is traded on the New York Stock Exchange under the symbol BKH. As of December 31, 2010, we had 4,667 common shareholders of record and approximately 24,000 beneficial owners, representing all 50 states, the District of Columbia and 6 foreign countries.

We have paid a regular quarterly cash dividend each year since the incorporation of our predecessor company in 1941 and expect to continue paying a regular quarterly dividend for the foreseeable future. At its January 27, 2011 meeting, our Board of Directors declared a quarterly dividend of $0.365 per share, equivalent to an annual dividend of $1.46 per share, marking 2011 as the 41st consecutive annual dividend increase for the Company.

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

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

Year ended December 31, 2010

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$0.36	$0.36	$0.36	$0.36
Common stock prices				
High	$30.83	$34.49	$33.31	$33.42
Low	$25.65	$27.34	$27.79	$29.32

Year ended December 31, 2009

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$0.355	$0.355	$0.355	$0.355
Common stock prices				
High	$27.84	$23.45	$26.90	$27.98
Low	$14.63	$17.36	$22.57	$23.16

UNREGISTERED SECURITIES ISSUED DURING 2010

There were no unregistered securities sold during 2010, except as were previously reported in our periodic and current reports to the SEC.

ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total Number of Shares Purchased(1)	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
October 1, 2010 –October 31, 2010	—	$—	—	—
November 1, 2010 –November 30, 2010	761	$32.42	—	—
December 1, 2010 –December 31, 2010	3,222	$30.75	—	—
Total	3,983	$31.07	—	—

(1) 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.

ITEM 6. SELECTED FINANCIAL DATA

Years Ended December 31, (dollars in thousands, except per share amounts)	2010	2009	2008	(1) 2007	2006
Total Assets	$3,711,509	$3,317,698	$3,379,889	$2,469,634	$2,241,798
Property, Plant and Equipment					
Total property, plant and equipment	$3,359,762	$2,975,993	$2,705,492	$1,847,435	$1,661,028
Accumulated depreciation and depletion	(864,329)	(815,263)	(683,332)	(509,187)	(462,557)
Capital Expenditures	$496,990	$347,819	$1,304,352	(2) $267,047	$308,450
Capitalization					
Current maturities	$5,181	$35,245	$2,078	$130,326	$4,249
Notes payable	249,000	164,500	703,800	37,000	145,500
Long-term debt, net of current maturities	1,186,050	1,015,912	501,252	503,301	554,411
Common stock equity	1,100,270	1,084,837	1,050,536	969,855	790,041
Total capitalization	$2,540,501	$2,300,494	$2,257,666	$1,640,482	$1,494,201
Capitalization Ratios					
Short-term debt, including current maturities	10.0 %	8.7 %	31.3 %	10.2 %	10.0 %
Long-term debt, net of current maturities	46.7 %	44.2 %	22.2 %	30.7 %	37.1 %
Common stock equity	43.3 %	47.1 %	46.5 %	59.1 %	52.9 %
Total	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %
Total Operating Revenues	$1,307,251	$1,269,578	$1,005,790	$574,838	$542,585
Net Income Available for Common Stock					
Utilities	$74,563	$57,071	$43,904	$31,633	$24,188
Non-regulated Energy	13,616	579	(4) (23,345)	(5) 49,897	37,098
Corporate expenses and intersegment eliminations	(19,494)	(3) 21,106	(3) (72,596)	(3) (5,872)	(5,514)
Income (Loss) from Continuing Operations	68,685	78,756	(52,037)	75,658	55,772
Discontinued operations[6]	—	2,799	157,247	23,491	25,757
Net loss attributable to non-controlling interest	—	—	(130)	(377)	(510)
Net income available for common stock	$68,685	$81,555	$105,080	$98,772	$81,019
Dividends Paid on Common Stock	$56,467	$55,151	$53,663	$50,300	$43,960

Common Stock Data[7] (in thousands)					
Shares outstanding, average	38,916	38,614	38,193	37,024	33,179
Shares outstanding, average diluted	39,091	38,684	38,193		