BLACK HILLS CORP /SD/
Form 10-K
February 26, 2010
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, 2009

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	IRS Identification Number 46-0458824

625 Ninth Street
Rapid City, South Dakota 57701

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 o No o

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

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

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

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes o No x

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

At June 30, 2009 $883,231,314

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, 2010
Common stock, $1.00 par value	38,961,358 shares

Documents Incorporated by Reference
Portions of the Registrant's Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2010 Annual Meeting of Stockholders to be held on May 25, 2010, 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
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 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.
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 formed to acquire and own the utility properties acquired in the Aquila Transaction, all which are now doing business as Black Hills Energy
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
Btu	British thermal unit
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CFTC	Commodity Futures Trading Commission
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
CO2	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

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Dth	Dekatherms
EBITDA	Earnings before interest, taxes, depreciation and amortization
Enserco	Enserco Energy Inc., a wholly-owned subsidiary of Black Hills Non-regulated Holdings
Enserco Facility	The $300 million committed stand alone credit facility that supports Enserco's marketing and trading operations, which currently expires May 7, 2010
EPA	U. S. Environmental Protection Agency
ERISA	Employee Retirement Income Security Act
EWG	Exempt Wholesale Generator
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
GAAP	Accounting principles generally accepted in the United States of America
GCA	Gas Cost Adjustment
GHG	Greenhouse gases
Great Plains	Great Plains Energy Incorporated
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
Indeck	Indeck Capital, Inc.
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
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
KW	Kilowatt
KWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Las Vegas II	Las Vegas II gas-fired power plant
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 public 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.
MTPSC	Montana Public Service Commission

MW	Megawatts
MWh	Megawatt-hours
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
PCA	Power Cost Adjustment
PGA	Purchase Gas Adjustment
PPA	Purchase Power Agreement
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
RMSA	Retiree Medical Savings Account
RTO	Regional Transmission Organization
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
SO2	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 Corporation, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings

ACCOUNTING PRONOUNCEMENTS

ASC	Accounting Standards Codification
ASC 105	ASC 105, "FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles - a replacement of FASB Standard No. 162"
ASC 260	ASC 260, "Earnings Per Share"
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 825	ASC 825, "Financial Instruments"
ASC 855	ASC 855, "Subsequent Events"
ASC 932-10-S99	ASC 932-10-S99, "Extractive Activities – Oil and Gas, SEC Materials"

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.

Our Chief Executive Officer and Chief Financial Officer have filed with the SEC, as exhibits to our Annual Report on Form 10-K, the certifications required by Section 302 of the Sarbanes Oxley Act regarding the quality of our public disclosure. Our Chief Executive Officer certified to the New York Stock Exchange following our 2009 annual shareholder meeting that he was not aware of violations by us of the New York Stock Exchange corporate governance listing standards.

Each of the foregoing documents is available in print to any of our shareholders upon request by writing to Black Hills Corporation, Attention: Investor Relations, 625 Ninth Street, Rapid City, South Dakota 57701.

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. 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. Forward-looking statements involve risks and uncertainties, and certain important factors can cause actual results to differ materially from those anticipated. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potentials," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurances that such indicated results will be realized. 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 following:

- Our ability to successfully integrate and profitably operate any recent and future acquisitions;
- Macro- and micro-economic changes in the economy and energy industry, including the impact of (i) consolidations and changes in competition, (ii) changing conditions in the capital and credit markets, which affect our ability to raise capital on favorable terms, and (iii) general economic and political conditions, including tax rates or policies and inflation rates;
- 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 obtain permanent financing for capital expenditures on reasonable terms either through long-term debt or issuance of equity;

- 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;
- Price risk due to marketable securities held as investments in employee benefit plans;
- The effect of accounting policies issued periodically by accounting standard-setting bodies;
- The accounting treatment and earnings impact associated with interest rate swaps;
- 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, may materially increase our generation and production costs and could render some of our generating units uneconomical to operate and maintain;
- 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;
- Additional liabilities for environmental conditions, including remediation and reclamation obligations, under environmental laws;
- 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, 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;
- The cost and effects on our business, including insurance, resulting from terrorist actions or responses to such actions or events;
- 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 in rate base for new power generation facilities;
- Our ability to recover our borrowing costs, including debt service costs, in our customer rates;
- The timing and extent of scheduled and unscheduled outages of power generation facilities;
- 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;
- 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 successfully complete labor negotiations with four of the six unions currently or soon to be in contract renewal negotiations;

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- Our ability to accurately estimate demand from our customers for natural gas;
- Weather and other natural phenomena;
- Changes in state laws or regulations that could cause us to curtail our independent power production or exploration and production activities;
- Our ability to meet production targets 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;
- 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 extent of our success in connecting natural gas supplies to gathering, processing and pipeline systems;
- Our ability to provide accurate estimates of proved oil and gas reserves, coal reserves and future production rates and associated costs; 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 (the "Company," "we," "us," "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, 2009, we had 2,171 employees, 749 of which 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 regulated Electric Utilities segment generates, transmits and distributes electricity to approximately 201,100 customers in South Dakota, Wyoming, Colorado and Montana and includes the operations of Cheyenne Light, a combination electric and gas utility, and its approximately 33,900 gas utility customers in Wyoming. Our regulated Gas Utilities segment serves approximately 528,300 natural gas utility customers in Colorado, Nebraska, Iowa and Kansas. Our regulated Electric Utilities own 630 MWs of generation and 8,182 miles of electric transmission and distribution lines, and our regulated Gas Utilities own 626 miles of intrastate gas transmission pipelines and 19,638 miles of gas distribution mains and service lines. Our regulated Electric and regulated Gas Utilities generated earnings from continuing operations of $57.1 million in the year ended December 31, 2009 and had total assets of $2.3 billion at December 31, 2009.

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 markets natural gas, crude oil and related services, primarily in the Unites 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 earnings from continuing operations of $0.6 million in the year ended December 31, 2009 and had total assets of $1.0 billion at December 31, 2009.

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 regulated 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 regulated Electric Utilities generate, transmit and distribute electricity to approximately 201,100 customers in South Dakota, Wyoming, Colorado and Montana. Additionally, they also distribute natural gas to approximately 33,900 natural gas utility customers served by Cheyenne Light 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 regulated Gas Utilities distribute and transport natural gas to our customers through our distribution network to approximately 528,300 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.

Since our three regulated electric utilities and our four regulated natural gas utilities have similar economic characteristics, we aggregate our electric utility operations into the regulated Electric Utilities segment and our gas utility operations into the regulated Gas Utilities segment.

Electric Utilities Segment

Capacity and Demand

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

By Entity

System Peak Demand (in MW)

	2009		2008		2007	
	Summer	Winter	Summer	Winter	Summer	Winter
Black Hills Power	387	392	409	407	430	361
Cheyenne Light	169	171	166	168	163	152
Colorado Electric	365	296	306 (a)	298 (a)	-	-
Total Electric Utilities	921	859	881	873	593	513

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

Regulated Power Plants

As of December 31, 2009, our regulated Electric Utilities' ownership interests in electric generation plants were as follows:

Unit	Fuel Type	Location	Ownership Interest %	Gross Capacity (MW)	Year Installed
Black Hills Power(1):					
Neil Simpson II	Coal	Gillette, WY	100	90.0	1995
Wyodak(2)	Coal	Gillette, WY	20	72.4	1978
Osage	Coal	Osage, WY	100	34.5	1948-1952
Ben French	Coal	Rapid City, SD	100	25.0	1960
Neil Simpson I	Coal	Gillette, WY	100	21.8	1969
Neil Simpson CT	Gas	Gillette, WY	100	40.0	2000
Lange CT	Gas	Rapid City, SD	100	40.0	2002
Ben French Diesel #1-5	Oil	Rapid City, SD	100	10.0	1965
Ben French CTs #1-4	Gas/Oil	Rapid City, SD	100	100.0	1977-1979
Cheyenne Light:					
Wygen II	Coal	Gillette, WY	100	95.0	2008
Colorado Electric(3):					
W.N. Clark #1-2	Coal	Canon City, CO	100	42.0	1955, 1959
Pueblo #6	Gas	Pueblo, CO	100	20.0	1949
Pueblo #5	Gas	Pueblo, CO	100	9.0	1941, 2001
AIP Diesel	Oil	Pueblo, CO	100	10.0	2001
Diesel #1-5	Oil	Pueblo, CO	100	10.0	1964
Diesel #1-5	Oil	Rocky Ford, CO	100	10.0	1964

(1) During 2008, we mobilized for the construction of Wygen III, a 110 MW mine-mouth coal-fired power plant. The plant is scheduled to be completed in April 2010. Black Hills Power will operate the plant and owns a 75% interest in the facility and MDU owns the remaining 25%. Our WRDC coal mine will furnish 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% (or 72.4 MW) by Black Hills Power. The baseload plant is operated by PacifiCorp and our WRDC coal mine furnishes all of the coal fuel supply for the plant.

(3) During 2009, we began the preparation to construct two 90 MW gas-fired power generation facilities to support the customers of Colorado Electric. These facilities are expected to be completed by December 31, 2011.

The following table shows the regulated Electric Utilities' annual average cost of fuel utilized to generate electricity and the average price paid for purchased power (excluding contracted capacity) per MWh during the last three years (dollars per MWh):

Fuel Source

	2009	2008(1)	2007(2)
Coal	$13.99	$11.41	$8.94
Gas and Oil	$85.52	$88.60	$68.04
Total Average Fuel Cost	$15.22	$13.18	$11.84
Purchased Power(3)	$28.93	$38.06	$29.87

(1) 2008 includes Colorado Electric from July 14, 2008 through December 31, 2008.
(2) Excludes Colorado Electric, which we did not acquire until July 14, 2008.
(3) Includes Colorado Electric acquired on July 14, 2008, Happy Jack commencing in October 2008, and Silver Sage commencing in October 2009.

Power Supply

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

	2009		2008		2007	
Coal-fired	39	%	44	%	42	%
Gas and Oil	1		1		2	
Total Generated	40	%	45	%	44	%
Purchased	60		55		56	
Total	100	%	100	%	100	%

Purchased Power. Various agreements have been executed to support our regulated 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 290 MW of capacity and energy in 2010, increasing to 300 MW in 2011;
- Black Hills Wyoming provides Cheyenne Light with 40 MW of energy and capacity from their Gillette CT and 60 MW of unit-contingent capacity and energy from their Wygen I facility under purchase power agreements. The 10-year PPA for the Gillette CT expires in August 2011. The PPA for the 60 MW of unit-contingent capacity and energy from the Wygen I facility had an extension approved by FERC in September 2009 and expires December 31, 2022. The Wygen I PPA includes an option for Cheyenne Light to purchase Black Hills Wyoming's ownership interest in the Wygen I facility during years one through seven during the term of the agreement. The purchase price related to the option is $2.55 million per MW which is equivalent of 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, provides up to 29.4 MW of renewable energy from the Happy Jack Wind Farm to Cheyenne Light. Under separate intercompany agreements, 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;
- Cheyenne Light's 20-year PPA with Duke Energy's Silver Sage wind farm, expiring in 2029, provides 30 MW of wind energy. Silver Sage commenced commercial operation in October 2009. Under separate intercompany agreements, Cheyenne Light sells 20 MW of energy from Silver Sage to Black Hills Power; and
- Colorado Electric's 20-year PPA with Black Hills Colorado IPP, expiring in 2031, will provide 200 MW of power to Colorado Electric from Black Hills Colorado IPP's combined-cycle turbines beginning on January 1, 2012

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

- Black Hills Power's agreement to supply up to 74 MW of capacity and energy to MDU for the Sheridan, Wyoming electric service territory through 2016. The sales to MDU have been integrated into Black Hills Power's control area and are considered part of our firm native load. This agreement permitted MDU the option to participate in the ownership of the Wygen III plant that is currently being constructed. In April 2009, MDU exercised this option and purchased a 25% ownership interest in Wygen III. In conjunction with the ownership interest transaction, the agreement to supply capacity and energy through 2016 was modified. The agreement now provides that once in commercial operation, the first 25 MW of the required 74 MW will be supplied from MDU's ownership interest in Wygen III. During periods of reduced production at Wygen III, or during periods when Wygen III is offline, MDU will be provided with its 25 MW from our other generation facilities or from system purchases;

- Black Hills Power's agreement with the City of Gillette, Wyoming, to provide the City its first 23 MW of capacity and energy annually. The sales to the City of Gillette have been integrated into Black Hills Power's control area and are considered part of our firm native load. The agreement renews automatically and requires a seven year notice of termination. As of December 31, 2009, neither party to the agreement had given a notice of termination;

- 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; and

- Black Hills Power's five-year PPA with MEAN executed in July 2009, which commences the month following the onset of commercial operations of Wygen III. Under this contract, MEAN will purchase 5 MW of unit-contingent capacity from Neil Simpson II and 5 MW of unit-contingent capacity from Wygen III.

- We have a purchase agreement with Basin Electric for the supply of 80 MW of capacity and energy through 2012 and a separate agreement to receive 80 MW of capacity and energy through 2012. The agreements were entered into with Basin Electric to accommodate delivery of electricity to Cheyenne Light's service territory.

Transmission and Distribution. Through our regulated 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, 2009, 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	1,007	2,403
Black Hills Power - Jointly Owned	SD, WY	47	-
Cheyenne Light	SD, WY	25	1,172
Colorado Electric	CO	509	3,019

Through Black Hills Power, we own 35% of a 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. Black Hills Power's electric system is located in the WECC region, and the total transfer capacity of the tie is 400 MW - 200 MW from West to East, and 200 MW from East to West. 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 the power price differentials between the two grids. Additionally, Black Hills Power's system is capable of directly interconnecting up to 80 MW of generation or load to the Eastern transmission grid.

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 2016, with the right to renew pursuant to the terms of PacifiCorp's transmission tariff.

Operating Statistics

The following tables summarize regulated sales revenues, sales quantities and customers for our regulated Electric Utilities segment. 2008 reported amounts include Colorado Electric from its July 14, 2008 acquisition date through December 31, 2008, whereas 2007 amounts do not include Colorado Electric:

Sales Revenues (in thousands)

	2009	2008	2007
Residential:			
Black Hills Power	$48,586	$46,854	$45,657
Cheyenne Light	29,198	31,394	24,060
Colorado Electric	66,548	32,620	-
Total Residential	144,332	110,868	69,717
Commercial:			
Black Hills Power	59,897	58,289	55,991
Cheyenne Light	51,280	51,609	38,871
Colorado Electric	56,002	28,531	-
Total Commercial	167,179	138,429	94,862
Industrial:			
Black Hills Power	20,014	21,432	21,974
Cheyenne Light	11,121	9,716	7,306
Colorado Electric	31,067	16,280	-
Total Industrial	62,202	47,428	29,280
Municipal:			
Black Hills Power	2,735	2,734	2,697
Cheyenne Light	932	973	797
Colorado Electric	4,408	2,289	-
Total Municipal	8,075	5,996	3,494
Contract Wholesale:			
Black Hills Power	25,358	26,643	25,240
Off-system Wholesale:			
Black Hills Power	32,212	63,770	35,210
Cheyenne Light	8,565	6,105	-
Colorado Electric	14,008	11,194	-
Total Off-system Wholesale	54,785	81,069	35,210
Other Sales Revenue:			
Black Hills Power	18,277	12,950	12,932
Cheyenne Light	718	394	208
Colorado Electric	4,226	1,346	-
Total Other Sales Revenue	23,221	14,690	13,140
Total Sales Revenues	$485,152	$425,123	$270,943

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Quantities Generated and Purchased (MWh)

	2009	2008	2007
Generated -			
Coal-fired:			
Black Hills Power	1,721,074	1,731,838	1,758,280
Cheyenne Light(1)	766,943	740,051	-
Colorado Electric	252,603	138,424	-
Total Coal	2,740,620	2,610,313	1,758,280
Gas and Oil-fired:			
Black Hills Power	46,723	61,801	90,618
Cheyenne Light	-	-	-
Colorado Electric	2,705	306	-
Total Gas and Oil	49,428	62,107	90,618
Total Generated:			
Black Hills Power	1,767,797	1,793,639	1,848,898
Cheyenne Light	766,943	740,051	-
Colorado Electric	255,308	138,730	-
Total Generated	2,790,048	2,672,420	1,848,898
Purchased:			
Black Hills Power	1,686,455	1,703,088	1,279,005
Cheyenne Light	651,201	590,622	1,047,782
Colorado Electric	1,991,058	1,028,029	-
Total Purchased	4,328,714	3,321,739	2,326,787
Total Generated and Purchased	7,118,762	5,994,159	4,175,685

(1) Represents the Wygen II plant that began providing electricity to Cheyenne Light customers on January 1, 2008.

Quantity Sold (MWh)

	2009	2008	2007
Residential:			
Black Hills Power	529,825	524,413	518,148
Cheyenne Light	255,134	255,345	251,313
Colorado Electric	589,526	284,294	-
Total Residential	1,374,485	1,064,052	769,461
Commercial:			
Black Hills Power	723,360	699,734	690,702
Cheyenne Light	583,986	586,151	561,963
Colorado Electric	666,563	330,870	-
Total Commercial	1,973,909	1,616,755	1,252,665
Industrial:			
Black Hills Power	353,041	414,421	434,627
Cheyenne Light	174,792	144,179	141,353
Colorado Electric	452,584	235,218	-
Total Industrial	980,417	793,818	575,980
Municipal:			
Black Hills Power	33,948	34,368	34,661
Cheyenne Light	3,456	3,669	3,658
Colorado Electric	37,244	19,740	-
Total Municipal	74,648	57,777	38,319
Contract Wholesale:			
Black Hills Power	645,297	665,795	652,931
Off-system Wholesale:			
Black Hills Power	1,009,574	1,074,398	678,581
Cheyenne Light	309,122	246,542	-
Colorado Electric	373,495	230,333	-
Total Off-system Wholesale	1,692,191	1,551,273	678,581
Total Quantity Sold:			
Black Hills Power	3,295,045	3,413,129	3,009,650
Cheyenne Light	1,326,490	1,235,886	958,287
Colorado Electric	2,119,412	1,100,455	-
Total Quantity Sold	6,740,947	5,749,470	3,967,937
Losses and Company Use:			
Black Hills Power	159,207	83,598	118,253
Cheyenne Light	91,654	94,787	89,495
Colorado Electric	126,954	66,304	-
Total Losses and Company Use	377,815	244,689	207,748
Total Energy	7,118,762	5,994,159	4,175,685

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Degree Days

	2009		2008		2007	
Heating Degree Days:	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average
Actual -						
Black Hills Power	7,753	8 %	7,676	6 %	6,627	(7)%
Cheyenne Light	7,411	-	7,435	1 %	6,964	(6)%
Colorado Electric	5,546	(1)%	2,204	(5)%	-	-
Cooling Degree Days:						
Actual -						
Black Hills Power	354	(41)%	482	(19)%	1,033	74 %
Cheyenne Light	203	(26)%	372	36 %	536	96 %
Colorado Electric	804	(13)%	500	(12)%	-	-

Electric Customers at Year-End

	2009	2008	2007
Residential:			
Black Hills Power	54,470	53,765	53,057
Cheyenne Light	35,943	35,205	35,175
Colorado Electric	81,622	81,561	-
Total Residential	172,035	170,531	88,232
Commercial:			
Black Hills Power	12,261	12,213	12,073
Cheyenne Light	4,932	4,563	4,381
Colorado Electric	11,101	11,155	-
Total Commercial	28,294	27,931	16,454
Industrial:			
Black Hills Power	38	40	41
Cheyenne Light	2	2	2
Colorado Electric	90	93	-
Total Industrial	130	135	43
Contract Wholesale:			
Black Hills Power	3	3	3
Other Electric Customers:			
Black Hills Power	143	3,010	3,012
Cheyenne Light	13	6	6
Colorado Electric	499	480	-
Total Other Electric Customers	655	3,496	3,018
Total Customers:			

Black Hills Power	66,915	69,031	68,186
Cheyenne Light	40,890	39,776	39,564
Colorado Electric	93,312	93,289	-
Total Customers	201,117	202,096	107,750

Cheyenne Light Natural Gas Distribution

Cheyenne Light's natural gas distribution system serves approximately 33,900 natural gas customers in Cheyenne and other portions of Laramie County, Wyoming. Our peak capacity was approximately 38,700 Dth during the year ending December 31, 2009. The following table summarizes certain operating information:

	2009	2008	2007
Sales Revenues (in thousands):			
Residential	$21,495	$28,059	$18,985
Commercial	9,821	13,751	9,437
Industrial	3,537	5,668	3,340
Other Sales Revenues	760	818	706
Total Sales Revenues	$35,613	$48,296	$32,468
Sales Margins (in thousands):			
Residential	$10,219	$10,083	$6,408
Commercial	3,266	3,177	2,268
Industrial	509	483	436
Other Sales Margins	760	818	707
Total Sales Margins	$14,754	$14,561	$9,819
Volumes Sold (Dth):			
Residential	2,516,699	2,582,248	2,380,945
Commercial	1,502,002	1,501,025	1,382,150
Industrial	722,776	689,945	664,807
Total Volumes Sold	4,741,477	4,773,218	4,427,902

Gas Utilities Segment

At December 31, 2009, our Gas Utilities owned 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

The following table summarizes the regulated Gas Utilities' sales revenues for December 31, 2009 and 2008 (in thousands):

Sales Revenues	2009	2008(1)
Residential:		
Colorado	$62,732	$27,928
Nebraska	127,120	60,624
Iowa	113,781	47,338
Kansas	70,848	31,456
Total Residential	374,481	167,346
Commercial:		
Colorado	13,357	6,356
Nebraska	43,472	20,705
Iowa	54,587	26,003
Kansas	22,629	10,092
Total Commercial	134,045	63,156
Industrial:		
Colorado	1,348	1,495
Nebraska	3,425	1,640
Iowa	2,191	1,581
Kansas	11,057	14,667
Total Industrial	18,021	19,383
Transportation:		
Colorado	732	278
Nebraska	10,569	4,703
Iowa	3,876	1,609
Kansas	5,389	2,409
Total Transportation	20,566	8,999
Other Sales Revenue:		
Colorado	100	39
Nebraska	2,077	907
Iowa	1,073	457
Kansas	3,213	1,600
Total Other Sales Revenue	6,463	3,003
Total Regulated:		
Colorado	78,269	36,096
Nebraska	186,663	88,579
Iowa	175,508	76,988
Kansas	113,136	60,224
Total Regulated	553,576	261,887
Non-regulated Services	26,736	15,189

Total Sales Revenues	$580,312	$277,076

(1) 2008 reported amounts include the regulated Gas Utilities for the period July 14, 2008 to December 31, 2008.

The following table summarizes the regulated Gas Utilities' sales margins for December 31, 2009 and 2008 (in thousands):

Sales Margins	2009	2008(1)
Residential:		
Colorado	$17,443	$5,984
Nebraska	44,638	19,460
Iowa	42,734	16,335
Kansas	28,999	12,436
Total Residential	133,814	54,215
Commercial:		
Colorado	3,176	1,131
Nebraska	11,785	4,952
Iowa	12,749	5,210
Kansas	6,484	2,693
Total Commercial	34,194	13,986
Industrial:		
Colorado	375	232
Nebraska	431	173
Iowa	244	105
Kansas	1,766	1,041
Total Industrial	2,816	1,551
Transportation:		
Colorado	732	278
Nebraska	10,569	4,703
Iowa	3,876	1,609
Kansas	5,389	2,409
Total Transportation	20,566	8,999
Other Sales Margins:		
Colorado	101	39
Nebraska	2,077	907
Iowa	1,073	457
Kansas	2,312	1,177
Total Other Sales Margins	5,563	2,580
Total Regulated:		
Colorado	21,827	7,664
Nebraska	69,500	30,195
Iowa	60,676	23,716
Kansas	44,950	19,756
Total Regulated	196,953	81,331
Non-regulated Services	11,643	3,895

Total Sales Margins	$208,596	$85,226

(1) 2008 reported amounts include the regulated Gas Utilities for the period July 14, 2008 to December 31, 2008.

The following table summarizes the regulated Gas Utilities' volumes for December 31, 2009 and 2008 (in Dth):

Volumes	2009	2008(1)
Residential:		
Colorado	6,355,275	2,344,549
Nebraska	12,619,682	5,115,805
Iowa	10,976,268	4,126,150
Kansas	6,878,243	2,682,850
Total Residential	36,829,468	14,269,354
Commercial:		
Colorado	1,444,360	563,169
Nebraska	5,189,630	2,133,433
Iowa	6,597,035	2,749,234
Kansas	2,696,870	1,063,356
Total Commercial	15,927,895	6,509,192
Industrial:		
Colorado	263,134	164,112
Nebraska	581,892	248,256
Iowa	333,324	196,841
Kansas	2,524,126	1,586,306
Total Industrial	3,702,476	2,195,515
Transportation:		
Colorado	807,999	347,822
Nebraska	25,311,501	12,930,165
Iowa	14,915,602	6,312,050
Kansas	14,069,182	7,215,038
Total Transportation	55,104,284	26,805,075
Other Volumes:		
Colorado	-	-
Nebraska	1,400	320
Iowa	68,290	18,301
Kansas	141,909	60,917
Total Other Volumes	211,599	79,538
Total Volumes:		
Colorado	8,870,768	3,419,652
Nebraska	43,704,105	20,427,979
Iowa	32,890,519	13,402,576
Kansas	26,310,330	12,608,467
Total Volumes	111,775,722	49,858,674

(1) 2008 reported amounts include the regulated Gas Utilities for the period July 14, 2008 to December 31, 2008.

Degree Days

Heating Degree Days:	2009 Actual	2009 Variance From 30-Year Average	2008 Actual	2008 Variance From 30-Year Average
Colorado	6,299	2 %	2,376	(7)%
Nebraska	6,238	5 %	2,458	-
Iowa	7,279	6 %	2,909	3 %
Kansas	4,989	-	1,897	(3)%

The following table summarizes the quantities of natural gas in storage at our regulated Gas Utilities at December 31, (in MMBtu):

	2009	2008
Natural gas in storage	6,866,550	7,317,931

The following table summarizes the regulated Gas Utilities' customers as of December 31, 2009 and 2008:

Customers	December 31, 2009	December 31, 2008
Residential:		
Colorado	65,586	64,601
Nebraska	179,873	177,432
Iowa	133,712	133,442
Kansas	97,446	96,593
Total Residential	476,617	472,068
Commercial:		
Colorado	3,590	3,579
Nebraska	15,218	15,034
Iowa	15,403	15,467
Kansas	9,510	9,463
Total Commercial	43,721	43,543
Industrial:		
Colorado	207	208
Nebraska	149	149
Iowa	90	84
Kansas	1,351	1,267
Total Industrial	1,797	1,708
Transportation:		
Colorado	22	21
Nebraska	4,579	4,758
Iowa	389	397
Kansas	1,077	1,174
Total Transportation	6,067	6,350
Other:		
Colorado	-	-
Nebraska	2	2
Iowa	71	69
Kansas	8	8
Total Other	81	79
Total Customers		
Colorado	69,405	68,409
Nebraska	199,821	197,375
Iowa	149,665	149,459
Kansas	109,392	108,505
Total Customers	528,283	523,748

Business Characteristics

Seasonal Variations of Business

Our regulated Electric Utilities and regulated 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 utilities. Conversely, 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 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 they were only implemented in 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. Accordingly, we face competition from other utilities and IPP companies for the right to provide baseload generation for Colorado Electric.

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. 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 regulated Gas Utilities, including Cheyenne Light, 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 regulated Electric Utilities that serve a purpose similar to the cost adjustment mechanisms in our regulated 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.

In South Dakota, we have three adjustment mechanisms: transmission, steam plant fuel (coal) and conditional energy cost adjustment. The transmission and steam plant fuel adjustment clauses requires an annual adjustment to rates for actual costs, therefore any savings or increased costs are passed on to the South Dakota customers. The conditional energy cost adjustment relates to purchased power and natural gas used to generate electricity. These costs are subject to calendar year \$2.0 million and \$1.0 million thresholds where Black Hills Power absorbs the first \$2.0 million of increased costs or retains the first \$1.0 million in savings. Beyond these thresholds, costs or savings are passed on to South Dakota customers through annual calendar-year filings.

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.

The above mechanisms allow the utilities to collect, or refund, the difference between the costs of commodities imbedded in our base rates and the actual costs of the commodities 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 regulated 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, 2009, 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. The Colorado legislature 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) at least 10% of its retail sales by 2010; (ii) 15% of retail sales by 2015; and (iii) 20% of retail sales by 2020. Of these amounts, 4% must be generated from solar renewable resources with one-half of the solar 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. We currently expect to be in compliance with the 2010 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 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.

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.

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. In that regard, our public utility subsidiaries provide FERC-jurisdictional services subject to FERC's oversight.

Our regulated Electric Utilities and our non-regulated subsidiary, Black Hills Wyoming, are authorized by FERC to make wholesale sales of electric capacity and energy at market-based rates under tariffs on file with FERC. As a condition of their market-based rate authority, each files Electric Quarterly Reports with FERC. Black Hills Power owns and operates FERC-jurisdictional interstate transmission facilities and provides open access transmission service under tariffs on file with FERC. Our regulated 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 holding company systems. As a 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	11/2006	9/2007	$ 16.3	$ 9.2	10.4%	51.0%	49.0%
Nebraska Gas (2)	Gas	12/2009	Pending	$ 12.1	Pending	Pending	Pending	Pending
Iowa Gas (3)	Gas	6/2008	7/2009	$ 13.6	$ 10.8	10.1%	51.4%	48.6%
Colorado Gas (4)	Gas	6/2008	4/2009	$ 2.7	$ 1.4	10.3%	50.5%	49.5%
Kansas Gas (5)	Gas	5/2009	10/2009	$ 0.5	$ 0.5	10.2%	50.7%	49.3%
Black Hills Power (6)	Electric	9/2008	1/2009	$ 4.5	$ 3.8	10.8%	57.0%	43.0%
Black Hills Power (7)	Electric	9/2009	Pending	$ 32.0	Pending	Pending	Pending	Pending
Black Hills Power (8)	Electric	10/2009	Pending	$ 3.8	Pending	Pending	Pending	Pending
Colorado Electric (9)	Electric	1/2010	Pending	$ 22.9	Pending	Pending	Pending	Pending

(1) In November 2006, Nebraska Gas filed for a $16.3 million rate increase. Interim rates were implemented in February 2007 and, in July 2007, the NPSC granted a $9.2 million increase in annual revenues based on an equity return of 10.4% on a capital structure of 51% equity and 49% debt. Nebraska Gas appealed the decision, and the district court affirmed the NPSC order in February 2008. Because Nebraska Gas collected interim rates subject to refund, it was required to refund to customers the difference between the higher interim rates and the final rates plus interest (approximately $5.6 million). The NPA appealed one aspect of our refund plan worth approximately $0.8 million. On April 15, 2009, the District Court affirmed the NPSC refund plan order, and thereby rejected NPA's appeal.

(2) On December 1, 2009, Nebraska Gas filed with the NPSC for a $12.1 million rate increase. The increase is to recover the cost of capital investments made and increased operating costs since the prior rate case in 2006. The proposed increase in revenue is about 6.5% and Nebraska Gas anticipates that interim rates subject to refund will be effective March 1, 2010. The proposed increase is subject to approval of the NPSC.

(3) On June 3, 2009, Iowa Gas received approval from the IUB to implement new natural gas service rates for its Iowa residential, commercial and industrial customers. The rates went into effect on July 27, 2009. The approved rates allow Iowa Gas to recover capital investments made in its natural gas distribution system and offset increasing operating costs due to inflation since the last rate increase in March 2006. The new rates represent approximately $10.8 million in additional revenue. The increase is based on a return on equity of 10.1%, with a capital structure of 51.4% equity and 48.6% debt.

(4) In June 2008, Colorado Gas filed for a $2.7 million rate increase. The increase was based on a proposed equity return of 11.5% on a capital structure of 50% equity and 50% debt. Interim rates were not available for collection in Colorado. On September 19, 2008, Colorado Gas filed the second phase of its rate request. On January 29, 2009, a settlement agreement was filed with the CPUC and a settlement was approved with new rates effective on April 1, 2009. The new rates included an increase in annual revenues of $1.4 million, based on a 10.25% return on equity with a capital structure of 50.48% equity and 49.52% debt.

(5) Kansas Gas has requested a GSRS in the amount of $0.5 million annually. The KCC issued an order on September 14, 2009, approving the request for $0.5 million and allowing Kansas Gas to continue collecting the $0.3 million previously authorized. The new rates had an effective date of October 1, 2009.

(6) 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. The new rates had an effective date of January 1, 2009.

(7) 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. Black Hills Power is seeking a $32.0 million, or approximately 26.6%, increase in annual utility revenues and anticipates that the new rates will be effective for our South Dakota customers on or around April 1, 2010. In the event a final order is not received by April 1, 2010, we have the ability to implement interim rates. The proposed rate increase is subject to approval by the SDPUC.

(8) On October 19, 2009, Black Hills Power filed a rate case with the WPSC requesting an electric revenue increase to recover costs associated with Wygen III and other generation, transmission and distribution assets and increased operating expenses incurred since 1995. Black Hills Power is seeking a $3.8 million, or approximately 38.95%, increase in annual utility revenues and anticipates that the new rates will be effective for our Wyoming customers on or around July 1, 2010, although recovery could be delayed until August 2010 as part of the regulatory process. The proposed rate increase is subject to approval by the WPSC.

(9) On January 6, 2010, Colorado Electric filed a rate case with CPUC requesting an electric revenue increase to recover increased operating expenses associated with electricity supply contracts, investment in equipment and electricity distribution facilities necessary to maintain and strengthen the reliability of the electric delivery system in Colorado. Colorado Electric is seeking a $22.9 million, or approximately 12.8%, increase in annual revenues with an anticipated effective date of mid-2010. The proposed increase is subject to CPUC approval.

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; (iii) the protection of plant and animal species and minimization of noise emissions; and, (iv) safety and health standards, practices and procedures that apply to the workplace and to the operation of our facilities.

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 Expenditures	Total (in millions)
2010	$ 15.4
2011	10.8
2012	2.5
Total	$ 28.7

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 permits. All of our facilities that are required to have NPDES permits have those permits in place and are in compliance with discharge limitations. 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.

Air Emissions

Our generation facilities are subject to federal, state and local laws and regulations relating to the protection of air quality. These laws and regulations cover, among other pollutants, carbon monoxide, SO_2, NO_x, mercury and particulate matter. In addition, CO_2 is included as a potential emission that may be subject to regulation in the future. 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 and Wyodak plants. Without purchasing additional allowances, we currently hold sufficient allowances to satisfy Title IV at all such plants through 2039. 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 our generating stations obtain operating permits. All of our existing facilities have received Title V permits, with the exception of Wygen II. As a new plant, this facility is allowed to operate under its construction permit until the Title V permit is issued by the state. The Title V application was submitted in 2008, with the permit expected in early 2010.

Multi-pollutant regulations

Approximately 60% of our electric generating capacity is coal-fired. In 2005, the EPA issued CAMR regulations with respect to SO_2, NO_x, and mercury emissions from certain power plants that burn fossil fuels. These rules implemented emission limits, monitoring and cap and trade requirements.

In February 2008, the United States Court of Appeals for the D.C. Circuit overturned the CAMR regulations; however, under this ruling, the EPA must either properly remove mercury from regulation under the hazardous air pollutant provisions of the Clean Air Act or develop standards requiring maximum achievable control technology for mercury emissions. Moreover, although this ruling impacts federal CAMR requirements, it does not necessarily impact state mercury legislation and rules. 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 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.

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.

Global Climate Change

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 CO2 emissions. We believe it is possible that greenhouse gases may be regulated in the near future. Although we cannot predict specifically how greenhouse gases will be regulated, any federally mandated GHG reductions or limits on CO2 emissions could have a material impact on our financial position or results of operations. In addition to federal legislative activity, climate regulations have been proposed in various states and 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.

In connection with climate change 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 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 and Wygen II 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. Investigations concluded that the wastes are relatively insoluble and will not measurably affect the post-mining ground water quality. The Osage power plant has an on-site ash impoundment that is near capacity and will be gradually transferring future ash disposal to 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 to be responsible for any such costs related to the solid waste from its 80% ownership interest in the Wyodak plant.

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. The EPA is currently developing ash disposal regulations, with a draft document expected in early 2010. Multiple regulatory options are being considered, one of which is regulating ash as a hazardous waste. If this option should become part of the final rule, 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 (MGP) sites. From our review of data provided by Aquila and subsequent discussions with contractors, we estimate that investigative and remedial action costs will be in the range of $1.4 million to $3.7 million. The acquisition also provided for a $1.0 million insurance recovery, which will be used to help offset the remediation costs of these sites. The remediation cost estimate could change materially due to results of further investigations, actions of environmental agencies or 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 diversified portfolio of generating plants; produces coal and markets and stores natural gas and crude oil. 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, 2009, the principal assets of our Oil and Gas segment included (i) operating interests in oil and natural gas properties, including 628 gross and 580 net wells in the San Juan Basin of New Mexico and Colorado (including significant holdings within the tribal lands of the Jicarilla Apache and Southern Ute Nations), the Powder River and Big Horn Basins of Wyoming, the Piceance Basin of Colorado, and the Nebraska section of the Denver Julesburg Basin; (ii) non-operated interests in oil and natural gas properties including 686 gross and 90 net wells located in California, Colorado, Louisiana, Montana, North Dakota, Oklahoma, Texas and Wyoming; 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, 2009, we had total reserves of approximately 119 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 33% of our reserves are located in the San Juan Basin of northwestern New Mexico, primarily in the East Blanco Field of Rio Arriba County, 31% are located in the Powder River Basin of Wyoming, primarily in the Finn-Shurley Field of Weston and Niobrara counties and 16% are located in the Piceance Basin of western Colorado.

Summary Oil and Gas Reserve Data

The following tables set forth summary information concerning our estimated proved developed and undeveloped oil and gas reserves and the 10% discounted present value of estimated future net revenues as of December 31, 2009 and 2008. The information presented is based on reports prepared by Cawley, Gillespie & Associates, Inc., an independent consulting and engineering firm located in Fort Worth, Texas. Reserves in 2009 were determined consistent with revised 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. Reserves in 2008 were determined consistent with SEC requirements in place at the time which utilized year-end product prices, 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. Additional information on our oil and gas reserves, related financial data and the revised SEC requirements can be found in Note 21 to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Proved Developed Reserves:	December 31, 2009			December 31, 2008		
	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)*	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)*
Wyoming	4,071	15,944	40,370	4,167	14,486	39,488
New Mexico	7	35,976	36,018	13	43,799	43,877
Colorado	1	17,547	17,553	1	22,563	22,569
Montana	12	1,575	1,647	26	2,231	2,387
Oklahoma	4	2,681	2,705	5	4,080	4,110
North Dakota	176	237	1,293	216	298	1,594
Other states	3	951	969	1	1,244	1,250
Total Proved Developed Reserves	4,274	74,911	100,555	4,429	88,701	115,275

*Oil Bbls are multiplied by six to convert to Mcfe.

Proved Undeveloped Reserves:	December 31, 2009			December 31, 2008		
	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)
Wyoming	484	2,304	5,208	444	5,327	7,991
New Mexico	-	3,030	3,030	-	13,352	13,352
Colorado	-	5,054	5,054	-	39,466	39,466
Montana	-	1,593	1,593	-	4,474	4,474
Oklahoma	-	-	-	9	2,604	2,658
North Dakota	516	768	3,864	303	508	2,326
Total Proved Undeveloped Reserves	1,000	12,749	18,749	756	65,731	70,267

Total Proved Reserves:	December 31, 2009			December 31, 2008		
	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)
Wyoming	4,555	18,248	45,578	4,611	19,813	47,479
New Mexico	7	39,006	39,048	13	57,151	57,229
Colorado	1	22,601	22,607	1	62,029	62,035
Montana	12	3,168	3,240	26	6,705	6,861
Oklahoma	4	2,681	2,705	14	6,684	6,768
North Dakota	692	1,005	5,157	519	806	3,920
Other states	3	951	969	1	1,244	1,250
Total Proved Reserves	5,274	87,660	119,304	5,185	154,432	185,542

	December 31, 2009	December 31, 2008
Proved developed reserves as a percentage of total proved reserves on an MMcfe basis	84 %	62 %
Proved undeveloped reserves as a percentage of total proved reserves on an MMcfe basis	16 %	38 %
Present value of estimated future net revenues, before tax (in thousands)	$134,322	$195,960

The following table reflects average wellhead pricing used in the determination of the reserves and the present value of estimated future net revenues, before tax:

	December 31, 2009	December 31, 2008
Gas per Mcf	$2.52	$4.44
Oil per Bbl	$53.59	$32.74

Drilling Activity

The following tables reflect the wells completed through our drilling activities for the last three years. In 2009, we participated in drilling 45 gross (10.76 net) development and exploratory wells, with a net well success rate of approximately 82%. 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,	2009		2008		2007	
Net Development wells	Productive	Dry	Productive	Dry	Productive	Dry
Wyoming	0.02	-	3.88	-	3.67	-
New Mexico	3.00	-	6.70	1.00	17.30	-
Montana	4.35	1.04	5.82	-	8.98	0.45
North Dakota	0.04	-	0.31	0.14	-	2.00
Other states	-	-	7.84	2.18	2.35	-
Total net developed wells	7.41	1.04	24.55	3.32	32.30	2.45

Year ended December 31,	2009		2008		2007	
Net Exploratory wells	Productive	Dry	Productive	Dry	Productive	Dry
Wyoming	-	0.50	0.75	-	0.61	-
New Mexico	-	-	2.00	-	1.60	-
Montana	0.50	0.37	-	-	0.27	0.25
North Dakota	0.03	-	0.76	-	0.37	-
Other states	0.91	-	-	-	-	-
Total net exploratory wells	1.44	0.87	3.51	-	2.85	0.25

As of December 31, 2009, we were participating in the drilling of 2 gross (0.3 net) wells, which had been commenced but not yet completed.

Recompletion Activity

Recompletion activities for the year ended December 31, 2009 and 2008 were not material to the overall operations of this segment.

Productive Wells

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

	Gross Wells			Net Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Wyoming	416	194	610	309.40	9.25	318.65
New Mexico	2	211	213	1.91	204.97	206.88
Colorado	1	95	96	-	71.16	71.16
Montana	3	240	243	0.48	49.96	50.44
North Dakota	29	-	29	2.51	-	2.51
Oklahoma	1	81	82	0.03	11.87	11.90
Other states	2	39	41	0.14	7.97	8.11
Total	454	860	1,314	314.47	355.18	669.65

Acreage

The following table summarizes our undeveloped, developed and total acreage by state as of December 31, 2009 (in thousands):

	Undeveloped		Developed		Total	
	Gross	Net	Gross	Net	Gross	Net
Wyoming	51,439	38,210	26,827	17,413	78,266	55,623
New Mexico	37,988	37,811	25,751	23,598	63,739	61,409
Colorado	45,813	34,945	38,627	32,731	84,440	67,676
Montana	658,486	115,531	105,716	19,658	764,202	135,189
Oklahoma	11,579	2,171	21,821	3,583	33,400	5,754
North Dakota	29,561	3,940	6,803	1,031	36,364	4,971
Other states	36,083	28,069	60,924	47,514	97,007	75,583
Total	870,949	260,677	286,469	145,528	1,157,418	406,205

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 the 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 Minerals Management Service and the Bureau of Indian Affairs, along with each Native American tribe, promulgate and enforce regulations pertaining to oil and natural gas operations 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. Additional changes of this nature are reasonably expected 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 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.

Global Climate Change. 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. We anticipate other states may implement 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. We hold varying interests in independent power plants operating in Wyoming and Idaho with a total net ownership of 120 MW as of December 31, 2009. We also hold investment interests in power-related funds with a net ownership interest of 3 MW.

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 approximately 93% 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, 2009, 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	Gas	Glenns Ferry, Idaho	50.0	%	5.5	1996
Rupert Cogeneration	Gas	Rupert, Idaho	50.0	%	5.5	1996

(1) During 2009, we began planning the construction of two 100 MW combined-cycle gas-fired power generation facilities. These facilities are expected to be completed by December 31, 2011.

(2) In January 2009, a 23.5% ownership interest in this plant was sold to MEAN.

Gillette CT. The Gillette CT is a simple-cycle, gas-fired combustion turbine located at our Gillette 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.

In January 2009, we completed the sale of a 23.5% undivided ownership interest in Wygen I to MEAN for a price of $51.0 million. The sales price was based on the current replacement cost for the coal-fired plant. In connection with this sale transaction, we entered into agreements with MEAN under which it will make payments for costs associated with administrative services, plant operations and coal supply provided by our Coal Mining subsidiary during the life of the facility. We also terminated a 10-year power purchase agreement under which MEAN was obligated to purchase 20 MW of power annually from Wygen I. We retain responsibility for plant operations following the transaction.

Idaho Cogeneration Facilities. Through partnership investments, we own 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. We account for our investment in the partnerships under the equity method of accounting. Electrical output from the facilities is sold to the Idaho Power Company under 20-year Firm Energy Agreements, which expire in 2016. Steam production is sold to Idaho Fresh-Pak, Inc. under agreements that expire in late 2016. The Rupert facility operated normally through 2009 with no adverse conditions. The steam host at Glenns Ferry suspended operations in late 2007. The Glenns Ferry plant had limited operations in 2009 and did not operate in 2008. The facility maintained revenues through the sale of the contracted gas supplies. The steam host suspension prevented the facility from meeting its QF commitment for 2008 and 2009. An application for a waiver of QF qualifying standards was approved by FERC for both years. Absent a contract with a new steam host, the continued suspension of the current steam host could have an adverse effect on the facility's operation, including its ability to meet QF requirements and the performance requirements under the related energy sales agreement in 2010. The Glenns Ferry facility may not be able to secure a waiver of QF qualifying standards, if needed, at the end of 2010. The Idaho partnerships have reserved their contractual rights with the steam host, as the steam host is jointly and severally liable under the Firm Energy Agreements with Idaho Power.

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. 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 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.

PURPA. The enactment of PURPA in 1978 provided incentives for the development of qualifying cogeneration facilities and small power production facilities that utilized certain alternative or renewable fuels. Prior to the enactment of the Energy Policy Act of 2005, FERC's regulations under PURPA required that electric utilities (i) purchase power generated by QFs at a price based on the purchasing utility's full avoided cost of producing power, (ii) sell back-up, interruptible, maintenance and supplemental power to the QF on a non-discriminatory basis, and (iii) interconnect with any QF in its service territory, and, if required, transmit power if they do not purchase it. Our Glenns Ferry and Rupert facilities are QFs. The enactment of the Energy Policy Act of 2005 did not affect the existing contracts for these facilities because they operate under contracts governed by laws in effect prior to the Energy Policy Act of 2005. In order to secure the benefits of contracts entered into pursuant to PURPA, our QFs must comply with certain operating requirements established by FERC, or secure a waiver of these requirements. If we fail to do so, we could incur contractual liability to the electric utility that purchases power generated by the QF.

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, including Wygen I and Gillette CT. All of 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 SO2 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 plants through 2039, without purchasing additional allowances.

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.

Global Climate Change. 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 6.0 million tons of coal in 2009. 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 historically approximated a 1:1 ratio. In recent years this has trended towards a ratio of approximately 2:1, 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 royalties of 12.5% and 9.0%, respectively, of the selling price on all federal and state coal. As of December 31, 2009, we had coal reserves of approximately 268 million tons, based on internal engineering studies. The reserve life is equal to approximately 41 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;
- Our 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, Wyoming 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.

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 2011.

We expect to increase our coal production to supply additional mine-mouth power generating capacity related to the 110 MW Wygen III plant, which is currently being constructed and is expected to utilize approximately 0.6 million tons of coal per year. The plant is expected to begin commercial operations in April 2010. In April 2009, a coal supply agreement was entered into between WRDC, Black Hills Power and MDU for coal supply to Wygen III through June 1, 2060.

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. Due to the economic limitations of transporting our lower-heat content coal, we do not actively promote the sale of our coal to distant markets.

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.

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 our WRDC coal mine. We have approved mining permits and are in compliance with other permitting programs administered by various regulatory agencies. Based on extensive reclamation studies, we have accrued approximately $15.3 million for reclamation costs as of December 31, 2009. If additional requirements or changes to current requirements are imposed in the future, we may experience a material increase in reclamation costs. 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 mining permit final contour requirements. The EPA is currently developing ash disposal regulations, with a draft document expected in early 2010. Multiple regulatory options are being considered, one of which is regulating ash as a hazardous waste. If this option should become part of the final rule, implementation requirements could have a material impact on our financial position and results of operations.

Energy Marketing Segment

Through our subsidiary, Enserco, we market natural gas and crude oil in specific regions of the United States and Canada. Our marketing operations are headquartered in Denver, Colorado, with a satellite sales office in Calgary, Alberta, Canada. Our gas and oil marketing efforts are concentrated in the Rocky Mountain, Western and Mid-continent regions of the United States and in Canada. The customers of our Energy Marketing segment include natural gas distribution companies, electric utilities, industrial users, oil and gas producers, other energy marketers and retail gas users.

Our average daily marketing physical volumes for the year ended December 31, 2009 were approximately 2.0 million MMBtu of gas and approximately 12,400 Bbls of oil.

Our Energy Marketing operations focus primarily on producer services and wholesale natural gas marketing. The business scope is comprised of the purchase, sale, storage and transportation of natural gas and crude oil, as well as a variety of services including asset optimization, price risk management and customized offerings to producer and end-use clients.

Our marketing business uses the following strategies:

- § Producer Services
  - Natural gas
  - Crude oil
- § Wholesale Trading
  - Transportation
  - Storage
  - Proprietary

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

	2009		
	Realized Gain (Loss)	Unrealized Gain (Loss)	Total Gain (Loss)
Wholesale trading (storage)	$2.2	$(1.7)	$0.5
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
Subtotal	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)
Wholesale trading (storage)	$6.6	$4.0	$10.6
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
Subtotal	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

	2007		
	Realized Gain (Loss)	Unrealized Gain (Loss)	Total Gain (Loss)
Wholesale trading (storage)	$27.0	$(1.0)	$26.0
Wholesale trading (transportation)	23.0	4.2	27.2
Producer services (natural gas)	5.0	(0.4)	4.6
Producer services (crude oil)	5.0	5.9	10.9
Subtotal	60.0	8.7	68.7
Wholesale trading (proprietary and other)	28.9	(3.8)	25.1
Total gross margin	$88.9	$4.9	$93.8

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 strong upside potential and definable downside risk. Of these contractual positions, 74% 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, 2009 were as follows:

	Term Until Expiration			
Region	Less than 2 Years (2010 and 2011)	2 to 4 Years (2012 – 2015)	Greater than 4 Years (2016 and beyond)	Total Volume
	(Bcf of natural gas)			
Rockies	63.5	53.4	25.0	141.9
West	23.4	13.0	10.9	47.3
MidContinent	72.5	1.0	-	73.5
Total Capacity	159.4	67.4	35.9	262.7

The firm storage capacity rights we held by region at December 31, 2009 included:

Region	Volume (Bcf)	Term
MidContinent/Upper Midwest	1.0	01/10 – 03/12
MidContinent/Upper Midwest	1.0	01/10 – 03/17
MidContinent/Upper Midwest	1.0	01/10 – 06/10
MidContinent/Upper Midwest	0.5	01/10 – 03/11
MidContinent/Upper Midwest	1.0	01/10 – 03/12*
MidContinent/Upper Midwest	1.0	01/10 – 03/13*
West/Northwest	1.0	01/10 – 03/11
West/Northwest	0.3	01/10 – 03/13*
West/Northwest	0.5	01/10 – 03/10

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

The following table summarizes the gas and oil inventory in storage at our Energy Marketing segment at December 31. These commodities are being held in inventory to capture the price differential between the time purchased and a subsequent sales date in the future. Much of the inventory has been sold forward or hedged forward to lock in a margin upon future withdrawal.

	2009	2008
Gas inventory volumes (MMBtu)	12,177,802	3,559,397
Crude inventory volumes (Bbl)	69,045	54,053

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 typically occur 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 are typically highest in the second and third quarters of our fiscal year.

Regulation. Various aspects of our marketing activities (including storage and transportation) are regulated by FERC. During 2007, following an internal review of natural gas marketing activities conducted within the Energy Marketing operations, we identified possible instances of noncompliance with regulatory requirements applicable to those activities. We notified the enforcement staff of FERC of our findings and shared information with the purpose of resolving any potential enforcement concerns. On August 24, 2009, FERC entered its Order approving a stipulation and consent agreement between FERC's Office of Enforcement and Enserco Energy Inc., which settled all matters presented to FERC in the 2007 self-report. Pursuant to the Agreement and Order, we agreed to pay a civil penalty of $1.4 million and submit semi-annual monitoring reports to FERC's Office of Enforcement for one year. No further enforcement action was taken or is expected relative to the matters presented to the Office of Enforcement. The settlement of this matter, including the payment of a civil penalty, did not have a material impact on our consolidated results of operations.

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 140,000 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 area.

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

Utilities Group:

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

Non-regulated Energy Group:

- Approximately 47,430 square feet of office space in Denver, Colorado.

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

Employees

At December 31, 2009, we had 2,171 full-time employees. Approximately 35% of the Company's employees are represented by a collective bargaining agreement. Out of a total of six collective bargaining agreements, four of these agreements are either currently in negotiations or planned for renewal negotiations during the first quarter of 2010. We have experienced no labor stoppages in recent years. The following table sets forth the number of employees by business group:

	Number of Employees
Corporate	335
Utilities	1,588
Non-regulated Energy	248
Total	2,171

At December 31, 2009, 749, or 35% of our employees (all within the Utilities Group), were covered by the following collective bargaining agreements:

Subsidiary	Number of Employees	Union Affiliation	Expiration Date of Collective Bargaining Agreement
Black Hills Power	187	IBEW Local 1250	March 31, 2010
Cheyenne Light	58	IBEW Local 111	June 30, 2011
Colorado Electric	159	IBEW Local 667	April 17, 2010
Iowa Gas	140	IBEW Local 204	April 27, 2010
Kansas Gas	24	Communications Workers of America, AFL-CIO Local 6407	December 31, 2011
Nebraska Gas	181	IBEW Local 244	December 31, 2009
Total	749		

At December 31, 2009, approximately 24% of our Utilities Group employees were eligible for regular or early retirement.

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.

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 market conditions then-prevailing, 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 financial crisis 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 prolonged recession may lead to an increase in late payments from retail and commercial 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.

We may not be able to effectively integrate the utility operations acquired from Aquila into our existing businesses and operations, or achieve the anticipated results from the Aquila Transaction.

We expect the Aquila Transaction to produce various benefits. Achieving the anticipated benefits of the acquisition is subject to a number of uncertainties, such as pending and future rate cases, and operational and financial synergies. As a condition of the Aquila Transaction, we agreed to continue employee compensation and benefit levels for all former Aquila employees through December 31, 2009. We began implementing several changes to compensation and benefit programs for all employees in late 2009 to become effective January 1, 2010 as part of unification initiatives deemed necessary to fully integrate these operations. For employees represented by a collective bargaining agreement, these benefit and compensation changes are being implemented in a manner consistent with terms of these agreements. We cannot provide assurance that the businesses we acquired from Aquila will be integrated in an efficient and effective manner or that they will be sufficiently profitable after our integration efforts have been completed.

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. Although we believe the IPP Transaction and the Aquila Transaction have strengthened our financial profile and creditworthiness, we cannot assure that our credit ratings will not be lowered. 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.

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 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 regulated gas and regulated 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 $185 million in taxes associated with the IPP Transaction and the Aquila Transaction. 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 in amounts of $27.8 million and $59.0 million after-tax, respectively. 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. The SEC adopted new reporting and accounting requirements for oil and gas companies that changed the way we test for potential ceiling test impairments (i.e. testing will be based on 12-month average of first day of the month commodity prices rather than a single date spot price as of the test date). The new requirements are effective for periods ending December 31, 2009 and apply to 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. The SEC has implemented revised reporting guidelines for reserves that apply to this Annual Report on Form 10-K for the period ending December 31, 2009. Key revisions include changes to the oil and gas pricing used to estimate reserves, the use of new technology for determining reserves and authorization for optional disclosure of probable and possible reserves.

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.

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.

Successful 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;
- 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 inability and cost of recruiting and retaining 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 weather variations from normal.

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.

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 adverse effects resulting from changes in natural gas and crude oil 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 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 regulated 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.

Our business is subject to substantial governmental regulation and permitting requirements as well as environmental liabilities, including those we assumed in connection with certain acquisitions. We may be adversely affected if we fail to achieve or maintain compliance with existing or future 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 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 regulations.

In January 2010, the Commodity Futures Trading Commission 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 ICE. 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 legislation, we cannot definitively estimate the effect of 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 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 35% of our employees are represented by a total of six collective bargaining agreements. Four of these agreements are either currently in negotiations or planned for renewal negotiations in early 2010.
- 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.

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 climate change and air emissions, including emission reduction mandates and renewable energy portfolio standards, 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, Colorado and Idaho. We are near completion of another fossil-fuel generating plant in Wyoming and preparing to commence construction on others in Colorado. Air emissions of fossil-fuel generating plants are subject to federal, state and tribal regulation. Recent developments under federal and state laws and regulation governing air emissions from fossil-fuel generating plants will likely result in more stringent emission limitations.

On October 22, 2009, the EPA filed a consent decree with environmentalists in the U.S. District Court for the District of Columbia, requiring the agency to propose a rule directed at coal and oil-fired power plants, setting maximum achievable control technology limits for air toxins, including mercury, by March 2011 and issue a final rule by

November 2011. While we expect this rule will be applicable to certain of our coal-fired units, we are unable to ascertain the full impact until the provisions of the proposed rule are known.

On April 2, 2007, the U.S. Supreme Court issued a decision in the case of Massachusetts v. U.S. Environmental Protection Agency, holding that CO2 and other GHG emissions are pollutants subject to regulation under the motor vehicle provisions of the Clean Air Act. The case was remanded to the EPA for further rulemaking to determine whether GHG emissions may reasonably be anticipated to endanger public health or welfare, or alternatively, to explain why GHG emissions should not be regulated. On April 17, 2009, the EPA signed its proposed Endangerment and Cause or Contribute Finding for Greenhouse Gases under Section 202 of the Clean Air Act. Although this proposal does not specifically address stationary sources, such as power generation plants, the general endangerment finding relative to GHG's could support such a proposal by the EPA for stationary sources. On October 30, 2009, the EPA published final rules regarding a mandatory GHG reporting regimen, the purpose of which would be to collect data to inform future policy and regulatory decisions.

In addition, the EPA published in the October 27, 2009 Federal Register a proposed rule that would tailor the major source applicability thresholds for GHG emissions under the Prevention of Significant Deterioration (PSD) and Title V programs of the Clean Air Act and set a PSD significance level for GHG emissions. EPA states this rule is necessary because they expect to soon promulgate regulations under the Clean Air Act to control GHG emissions and as a result, trigger PSD and Title V applicability requirements. This proposed rule would phase in the applicability thresholds for both the PSD and Title V programs for sources of GHG emissions. The first phase, which would last six years, would establish a temporary level for the PSD and Title V applicability thresholds at 25,000 tons per year on a carbon dioxide equivalent basis and would also establish temporary PSD significance levels. All our generating units would exceed this threshold and if the pending rule to control GHG emissions is published and finalized, we would be required upon Title V permit renewal, to evaluate options for reducing GHG emissions, to possibly include a Best Available Control Technology review that could result in more stringent emissions control practices and technologies. In the second phase of this proposed rule, EPA would within five years of the rule being final, review the first phase and promulgate revised applicability and significance level thresholds as appropriate.

Finally, federal legislation is currently under consideration in the U.S. Congress, including H.R. 2454, "the American Clean Energy and Security Act of 2009," which was approved by the U.S. House of Representatives on June 26, 2009. This legislation would affect electric generation and electric and natural gas distribution companies. H.R. 2454 also proposes a national renewable electricity standard, which would implement a phased process ultimately mandating that 20% of electricity sold by retail suppliers be met by energy efficiency improvements and renewable energy resources by 2020.

The climate bill under consideration in the U.S. Senate is S.1733, "the Clean Energy Jobs and American Power Act." S.1733 was passed by the Environment and Public Works Committee November 5, 2009, but is not expected to be brought to the Senate floor in its current form. Other committees with jurisdiction include Finance, Energy and Natural Resources, Commerce, Agriculture, and Foreign Relations. The Senate Energy and Natural Resources Committee passed S.1462, "the American Clean Energy Leadership Act of 2009," on July 16, 2009, which would establish a 15% Renewable Electricity Standard by 2021. If the Senate were to act in 2010, it is likely the climate change and renewable electricity standard portions would be combined into one bill.

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.

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More stringent GHG emissions limitations or other energy efficiency requirements, however, 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.

We own regulated electric utilities that serve customers in South Dakota, Wyoming, Colorado and Montana. To varying degrees, Colorado and Montana have each adopted mandatory renewable portfolio standards that require electric utilities to supply a minimum percentage of the power delivered to customers from renewable resources (e.g., wind, solar, biomass) by a certain date in the future. These renewable energy portfolio standards have increased the power supply costs of our electric operations. If these states increase their renewable energy portfolio standards, or if similar standards are imposed by the other states in which we operate electric utilities, our power supply costs will further increase. Although we will seek to recover these higher costs in rates, any unrecovered costs could have a material negative impact on our results of operations and financial condition.

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, including trading of emission allowances and switching to other fuels. For example, in order to meet the federal Clean Air Act limits for sulfur dioxide emission from power plants, coal users may need to install scrubbers, use sulfur dioxide 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. Recent and new proposals calling for reductions in emissions of carbon dioxide and other greenhouse gases could significantly increase the cost of operating existing coal-fueled power plants and could inhibit construction of new coal-fired power plants. 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.

The Energy Policy Act of 2005 increased FERC's civil penalty authority for violation of FERC statutes, rules and orders. FERC can now impose penalties of $1.0 million per violation, per day, and other regulatory agencies that impose compliance requirements relative to our business also have civil penalty authority. Many rules that were historically subject to voluntary compliance are now mandatory and subject to potential civil penalties for violations. If a serious 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. In addition, a limited number of states have implemented or are considering or currently implementing methods to introduce and promote retail competition. 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.

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, NPSC, IUB and KCC 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 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. In addition, the Pension Protection Act of 2006 changed the minimum funding requirements for defined benefit pension plans beginning in 2008.

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.

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 auditors 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 $353.7 million of goodwill on our consolidated balance sheet as of December 31, 2009. 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. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matter was submitted to a vote of security holders during the fourth quarter of 2009.

ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT

David R. Emery, age 47, was elected Chairman in April 2005 and has been President and Chief Executive Officer and a member of the Board of Directors since January 2004. Prior to that, he was our President and Chief Operating Officer – Retail Business Segment from April 2003 to January 2004 and Vice President – Fuel Resources from January 1997 to April 2003. Mr. Emery has 20 years of experience with the Company.

Garner M. Anderson, age 47, has been Vice President, Treasurer and Chief Risk Officer since October 2006. He served as Vice President and Treasurer since July 2003. Mr. Anderson has 21 years of experience with the Company, including positions as Director – Treasury Services and Risk Manager.

Roxann R. Basham, age 48, has been Vice President – Governance and Corporate Secretary since February 2004. Prior to that, she was our Vice President – Controller from March 2000 to January 2004. Ms. Basham has a total of 26 years of experience with the Company.

Jeffrey B. Berzina, age 37, has been our Vice President – Corporate Controller since June 1, 2009. He served as Vice President – Finance from November 2008 to May 2009; as Assistant Controller from 2004 to 2008; and as Director of Financial Reporting from 2002 to 2004. Mr. Berzina has nine years of experience with the Company. Prior to joining the Company, he had six years of experience in public accounting.

Scott A. Buchholz, age 48, has been our Senior Vice President – Chief Information Officer since the close of the Aquila Transaction in July 2008. Prior to joining the Company, he was Aquila's Vice President of Information Technology from June 2005 until July 2008, Six Sigma Deployment Leader/Black Belt from January 2004 until June 2005, and General Manager, Corporate Information Technology from February 2002 until January 2004. He was employed with Aquila for 28 years.

Anthony S. Cleberg, age 57, has been Executive Vice President and Chief Financial Officer since July 2008. He was an independent investor, developer and consultant with companies in Colorado and Wyoming from 2002 until joining the Company in 2008. Prior to his consulting role, he was the Executive Vice President and Chief Financial Officer of two publicly-traded companies: Washington Group, International, Inc. a large engineering and construction company involved in power plant construction and mining operations, and Champion Enterprises, a builder of factory-built housing. Before his CFO roles, he spent 15 years in various senior financial positions with Honeywell International, Inc. and eight years in public accounting at Deloitte & Touche, LLP. Mr. Cleberg currently sits on the board of directors of CAN Surety.

Linden R. Evans, age 47, has been President and Chief Operating Officer – Utilities since October 2004. Mr. Evans served as the Vice President and General Manager of our former communication subsidiary since December 2003, and served as our Associate Counsel from May 2001 to December 2003. Mr. Evans has eight years of experience with the Company.

Steven J. Helmers, age 53, has been our Senior Vice President, General Counsel since January 2004. He served as our Senior Vice President, General Counsel and Corporate Secretary from January 2001 to January 2004. Mr. Helmers has nine years of experience with the Company.

Richard W. Kinzley, age 44, has been our Vice President, Strategic Planning and Development since September 2008 and Director of Corporate Development from 2000 until September 2008. Mr. Kinzley has 10 years of experience with the Company. Prior to joining the Company, he had nine years of experience in public accounting and two years of experience in industry.

Perry S. Krush, age 50, has been our Vice President – Supply Chain since June 1, 2009. He served as our Vice President – Controller from December 2004 to May 2009. Mr. Krush has 21 years of experience with the Company, including positions as Controller – Retail Operations from 2003 to 2004, Director of Accounting for our subsidiary, now known as Black Hills Non-regulated Holdings, and Accounting Manager – Fuel Resources from 1997 to 2003.

Robert A. Myers, age 52, has been our Senior Vice President – Human Resources since January 2009 and served as our Interim Human Resources Executive since June 2008. He was a partner with Strategic Talent Solutions, a human resources consulting firm, from October 2006 until December 2008, Senior Vice President – Chief Human Resource Officer for Devon Energy from March 2006 until September 2006, and Senior Vice President and Chief Human Resource Officer at Reebok International, Ltd from November 2003 until January 2006. He has over 28 years of service in key human resources leadership roles.

Thomas M. Ohlmacher, age 58, has been the President and Chief Operating Officer of our Non-regulated Energy Group since November 2001. He served as Senior Vice President – Power Supply and Power Marketing from January 2001 to November 2001 and Vice President – Power Supply from 1994 to 2001. Prior to that, he held several positions with our company since 1974. Mr. Ohlmacher has 35 years of experience with the Company.

Kyle D. White, age 50, has been Vice President – Regulatory and Corporate Affairs since January 2001 and Vice President – Marketing and Regulatory Affairs since July 1998. Mr. White has 27 years of experience with the Company.

Lynnette K. Wilson, age 50, has been our Senior Vice President – Communications and Investor Relations since the close of the Aquila acquisition in July 2008. Prior to joining the Company, she was Aquila's Vice President of Communications and Investor Relations from June 2006 until July 2008 and Issues Strategist for the Office of the Chairman and Chief Executive Officer from January 2002 until May 2006. She was employed with Aquila for eleven years.

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, 2009, we had 4,836 common shareholders of record and approximately 14,500 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 28, 2010 meeting, our Board of Directors declared a quarterly dividend of $0.36 per share, equivalent to an annual dividend of $1.44 per share, marking 2010 as the 40th 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, 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

Year ended December 31, 2008

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$0.350	$0.350	$0.350	$0.350
Common stock prices				
High	$43.98	$39.66	$39.23	$31.59
Low	$33.21	$31.70	$30.10	$21.73

UNREGISTERED SECURITIES ISSUED DURING 2009

There were no unregistered securities sold during 2009, 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, 2009 – October 31, 2009	104	$ 25.66	-	-
November 1, 2009 – November 30, 2009	272	$ 23.92	-	-
December 1, 2009 – December 31, 2009	4,341	$ 25.22	-	-
Total	4,717	$ 25.15	-	-

(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

Certain items related to 2007 through 2005 have been restated from prior year presentation to reflect the classification of the 2008 IPP Transaction as discontinued operations and non-controlling interest (see Notes 1 and 22 of the Notes to the Consolidated Financial Statements in Item 8 of this Annual Report on Form 10-K).

Years Ended December 31,	2009	2008	2007	2006	2005
Total Assets (in thousands)	$ 3,317,698	$ 3,379,889	$ 2,469,634	$ 2,241,798	$ 2,120,258
Property, Plant and Equipment (in thousands)					
Total property, plant and equipment	$ 2,975,993	$ 2,705,492	$ 1,847,435	$ 1,661,028	$ 1,351,366
Accumulated depreciation and depletion	(815,263)	(683,332)	(509,187)	(462,557)	(407,039)
Capital Expenditures (in thousands)	$ 347,819	$ 1,304,352	$ 267,047	$ 308,450	$ 208,856
Capitalization (in thousands)					
Current maturities	$ 35,245	$ 2,078	$ 130,326	$ 4,249	$ 4,237
Notes payable	164,500	703,800	37,000	145,500	55,000
Long-term debt, net of current maturities	1,015,912	501,252	503,301	554,411	558,725
Common stock equity	1,084,837	1,050,536	969,855	790,041	738,879
Total capitalization	$ 2,300,494	$ 2,257,666	$ 1,640,482	$ 1,494,201	$ 1,356,841
Capitalization Ratios					
Short-term debt, including current maturities	8.7 %	31.3 %	10.2 %	10.0 %	4.4 %
Long-term debt, net of current maturities	44.2	22.2	30.7	37.1	41.2
Common stock equity	47.1	46.5	59.1	52.9	54.4
Total	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %
Total Operating Revenues (in thousands)	$ 1,269,578	$ 1,005,790	$ 574,838	$ 542,585	$ 496,768
Net Income Available for Common Stock (in thousands)					
Utilities	$ 57,071	$ 43,904	$ 31,633	$ 24,188	$ 20,119
Non-regulated Energy	579 (1)	(23,345) (3)	49,897	37,098	43,444
Corporate expenses and intersegment eliminations	21,106 (2)	(72,596) (4)	(5,872)	(5,514)	(13,491)
Income (Loss) from Continuing Operations	78,756	(52,037)	75,658	55,772	50,072
Discontinued operations(5)	2,799	157,247	23,491	25,757	(16,375)
Net loss attributable to non-controlling interest	-	(130)	(377)	(510)	(277)

Preferred dividends	-	-	-	-	(159)
Net income available for common stock	$ 81,555	$ 105,080	$ 98,772	$ 81,019	$ 33,261
Dividends Paid on Common Stock (in thousands)	$ 55,151	$ 53,663	$ 50,300	$ 43,960	$ 42,053
Common Stock Data(6) (in thousands)					
Shares outstanding, average	38,614	38,193	37,024	33,179	32,765
Shares outstanding, average diluted	38,684	38,193	37,414	33,549	33,288
Shares outstanding, end of year	38,968	38,636	37,796	33,369	33,156
Earnings (Loss) Per Share of Common Stock(6) (in dollars)					
Basic earnings (loss) per average share -					
Continuing operations	$ 2.04	$ (1.37)	$ 2.04	$ 1.68	$ 1.52
Discontinued operations	0.07	4.12	0.63	0.77	(0.50)
Non-controlling interest	-	-	(0.01)	(0.01)	-
Total	$ 2.11	$ 2.75	$ 2.66	$ 2.44	$ 1.02
Diluted earnings (loss) per average share -					
Continuing operations	$ 2.04	$ (1.37)	$ 2.02	$ 1.66	$ 1.50
Discontinued operations	0.07	4.12	0.63	0.77	(0.49)
Non-controlling interest	-	-	(0.01)	(0.01)	(0.01)
Total	$ 2.11	$ 2.75	$ 2.64	$ 2.42	$ 1.00
Dividends Declared per Share	$ 1.42	$ 1.40	$ 1.37	$ 1.32	$ 1.28
Book Value Per Share, End of Year	$ 27.84	$ 27.19	$ 25.66	$ 23.68	$ 22.28

Years ended December 31,	2009	2008	2007	2006	2005
Return on Average Common Stock Equity					
(year-end)	7.6 %	10.4 %	11.2 %	10.6 %	4.5 %
Operating Statistics:					
Generating capacity (MW):					
Utilities (owned generation)	630	630	435	435	435
Utilities (purchased capacity)	430	420	50	50	50
Independent power generation(7)	120	141	983	989	1,000
Total generating capacity	1,180	1,191	1,468	1,474	1,485
Electric Utilities:					
MWh sold:(8)					
Retail electric	4,403,459	3,532,402	2,636,425	2,552,290	2,472,051
Contracted wholesale	645,297	665,795	652,931	647,444	619,369
Wholesale off-system	1,692,191	1,551,273	678,581	942,045	869,161
Total MWh sold	6,740,947	5,749,470	3,967,937	4,141,779	3,960,581
Gas Utilities:(9)					
Gas Dth sold	56,671,438	23,053,599	-	-	-
Transport volumes	55,104,284	26,805,075	-	-	-
Oil and gas production sold (MMcfe)	12,463	13,534	14,627	14,414	13,745
Oil and gas reserves (MMcfe)	119,304	185,542	207,806	199,092	169,583
Tons of coal sold (thousands of tons)	5,955	6,017	5,049	4,717	4,702
Coal reserves (thousands of tons)	268,000	274,000	280,000	285,000	290,000
Average daily marketing volumes:					
Natural gas physical sales (MMBtu)	1,974,300	1,873,400	1,743,500	1,598,200	1,427,400
Crude oil physical sales (Bbls) (10)	12,400	7,880	8,600	8,800	-

(1) Includes a $27.8 million after-tax ceiling test impairment charge to our crude oil and natural gas properties taken in 2009 and a $16.9 million after-tax gain on sale of 23.5% ownership interest in Wygen I.
(2) Includes a $36.2 million after-tax unrealized mark-to-market gain related to interest rate swaps.
(3) Includes a $59.0 million after-tax ceiling test impairment charge to our crude oil and natural gas properties taken in 2008.
(4) Includes a $61.4 million after-tax unrealized mark-to-market loss related to interest rate swaps.
(5) 2008 includes a $139.7 million after-tax gain on the IPP Transaction and 2005 includes long-lived asset impairment charges of approximately $33.9 million after-tax
(6) In February 2007, we issued 4.2 million shares of common stock, which dilutes our earnings per share in subsequent periods.
(7) Includes 825 MW in 2007, 2006 and 2005, which have been reported as "Discontinued operations."
(8) Includes regulated electric and gas utilities acquired on July 14, 2008.
(9) Excludes Cheyenne Light.
(10) Represents crude oil marketing activities in the Rocky Mountain region, which began May 1, 2006.

For additional information on our business segments see - Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Item 7A. Quantitative and Qualitative Disclosures about Market Risk and Note 17 to the Consolidated Financial Statements in this Annual Report on Form 10-K.

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

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

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

Our Utilities Group consists of our regulated Electric and Gas utility segments. Our Electric Utilities segment generates, transmits and distributes electricity to approximately 201,100 customers in South Dakota, Wyoming, Colorado and Montana and includes the operations of Cheyenne Light and its approximately 33,900 gas utility customers in Wyoming. Our Gas Utilities segment serves approximately 528,300 natural gas customers in Colorado, Nebraska, Iowa and Kansas. Our Non-regulated Energy Group engages in the production of coal, natural gas and crude oil primarily in the Rocky Mountain region; the production of electric power through ownership of a portfolio of generating plants and the sale of electric power and capacity primarily under mid- and long-term contracts; and the marketing of natural gas, crude oil and related services.

Industry Overview

The United States energy industry experienced a second consecutive tumultuous year in 2009. Energy commodity prices, which were near historic highs in July 2008, with natural gas trading over $13.00 per Mcf and crude oil selling for nearly $145 per barrel, experienced dramatic declines to less than $2.80 and $35, respectively, by February 2009. The global economic crisis that commenced in late 2008 and continued through 2009 significantly reduced energy demand. In addition, domestic energy prices continued to be influenced by global factors, including foreign economic conditions (especially in China and Asia), the policies of OPEC and other large foreign oil producers, and political tensions and conflict in many regions. Mild weather dominated the United States during much of the year, further reducing demand for fuel used for power generation and heating.

Beginning in late summer 2008, a proliferation of sub-prime lending produced a global credit crisis. Other credit quality concerns also emerged, creating an international-scale financial crisis, plunging the United States economy into its worst recession since the 1930s. The capital markets were impacted dramatically by the crisis during late 2008 and the first several months of 2009, severely inhibiting the ability of companies to raise both debt and equity capital, and significantly increasing the cost of capital. For creditworthy companies, the capital markets improved materially beginning in the second quarter of 2009.

Like other United States industries, the energy industry is faced with numerous uncertainties, both short and long-term. Many utilities have large capital spending needs over the next few years to replace aging infrastructure, and to add new assets such as transmission lines and renewable energy resources. Utility companies generally are less impacted by economic downturns, but the prolonged, severe recession has affected the demand for energy services and the ability of customers to pay their utility bills, particularly in certain parts of the country. The recession has also impacted the ability of companies to obtain the capital necessary for infrastructure expansion.

The state utility regulatory climate in 2009 remained relatively constructive among government, industry and consumer representatives. In the seven-state region encompassing our utility operations, regulators were willing to establish rates based on multi-year considerations, including fuel and other reasonable cost adjustments, justifiable capital expenditures for maintenance and expansion of energy systems, and a response to environmental concerns through demand management and energy efficiency programs. Challenges remain, however, in obtaining satisfactory rate recovery for utility investments due to the general state of the economy and concern by regulators in various states that utility rate increases may cause further harm to local economies.

At the federal level, the November 2008 elections caused a significant change in the domestic political environment, and a dramatic shift in domestic policy. The passage of a major economic stimulus package by Congress early in 2009, and the bailout of several "too large to fail" financial firms and automobile manufacturers, set the stage for an emphasis on increased regulation and government oversight of industry, which continued throughout the year. Despite all of the focus on the economy, environmental issues remained a priority for the President and many in Congress. Federal legislation, mandating the reduction of GHG emissions utilizing a "cap-and-trade" system and increased renewable energy use, passed the House and was introduced in the Senate. Although it did not pass during 2009, the legislation remains a key priority of the President and Congressional leadership. In addition, in late 2009, Congress focused on the passage of major healthcare reform legislation. These potential legislative actions could have significant macroeconomic consequences, as the associated cost increases may cause a dramatic increase in consumer costs for products and services, including rates for electricity and other energy in the mid- to long-term. State legislatures also remained active on environmental issues in 2009, with a majority of states now having adopted some form of renewable energy standard, including some in which we operate. In addition, several states have passed greenhouse gas emissions legislation, which places limits on the emissions of CO2 and other greenhouse gases.

Progress in the domestic energy industry during 2009 included increasing levels of domestic natural gas production activity, particularly related to the various shale "resource plays"; planning and construction of liquefied natural gas port facilities; proposals for additional gas-fired, coal-fired and nuclear power plants; planning for additional electric transmission capacity; and the advancement of renewable energy resources and utilization.

The energy industry continues to adjust to change, although the economic crisis suppressed the recent trend of consolidation in the electric and gas utility sectors. The energy marketplace continues to respond to increased the oversight and enforcement activity of FERC, and increased environmental and emissions reviews and mandates. In recent years, several state regulatory agencies allowed electric utilities to construct and operate power plants in vertically integrated structures after years of discouraging or prohibiting such activity.

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

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

In early 2008, the domestic coal industry benefited from a positive price environment, in large part due to high and volatile natural gas prices. Coal prices have moderated considerably in response to a trend of lower overall natural gas prices. Powder River Basin coal (8800 Btu per pound) was $13.50 per ton in December 2008 and by the end of 2009 it was as low as $6.50 per ton or a decline of 52%. Fossil fuel combustion continues to be a contentious domestic and international public policy issue, as many nations, including United States allies, advocate reductions in CO_2 and other emissions. Many states now encourage the energy industry to invest in renewable energy resources, such as wind or solar power, or the use of bio-mass as a fuel. In many instances, renewable energy use is mandated by state regulators. Several years ago, the State of California mandated that future imports of power must come from power plants with emission levels no greater than combined-cycle natural gas-fired plants. Such restrictions may alter transmission flow of power in western states, as a large percentage of current power generation in the western grid comes from coal sources.

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

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

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

Business Strategy

We are a customer-focused integrated energy company. Our business is comprised of electric and natural gas utility operations, power generation, and fuel assets and services, including production and marketing operations for crude oil, natural gas and coal. Our focus on customers - whether they are utility customers or non-regulated generation, fuel or marketing customers - provides opportunities to expand our businesses by constructing additional rate base assets to serve our utility customers and expand our non-regulated energy holdings to provide additional products and services to our wholesale customers.

The diversity of our energy operations reduces reliance on any single business segment to achieve our strategic objectives. It mitigates our overall corporate risk and enhances our ability to earn stronger returns for shareholders over the long term. Despite challenging conditions in the capital markets over the past year, we have sufficient liquidity and solid cash flows, and expect to have continued access to the capital markets as needed. Consequently, our financial foundation is sound and capable of supporting an expansion of operations in both the near and long term.

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During 2009, we focused on the continued integration of the five utility properties acquired from Aquila in mid-2008 and the achievement of certain operating efficiencies made possible by the acquisition. During the year, we consolidated compensation, performance management, employee benefits, payroll, field resource, and customer information systems and processes. During 2010, we expect to achieve additional operating efficiencies by consolidating accounting and information systems, along with systems and processes for procurement, inventory, outage management, utility engineering, power marketing, resource planning and other areas.

Our long-term strategy focuses on growing both our utility and non-regulated energy businesses, primarily by increasing our customer base and providing superior service to both utility and non-regulated energy customers. In our natural gas and electric utilities, we intend to grow our asset base to serve projected customer demand in our existing utility service territories through expansion of infrastructure and construction of new rate-based power generation facilities. We also plan to pursue acquisitions of additional utility properties, primarily in the Great Plains and Rocky Mountain regions of the country. By maintaining our high customer service and reliability standards in a cost-efficient manner, our goal is to secure appropriate rate recovery to provide solid economic returns on our utility investments.

In our fuel production operations, we will continue to prudently grow and develop our existing inventory of oil and gas reserves, while we strive to maintain strong relationships with mineral owners, landowners and regulatory authorities. Our ability to grow both production and reserves may be hindered in the short-term by low price levels for both crude oil and natural gas resulting from the impact on demand from a weakened economy. In the long-term, however, we believe that demand for both natural gas and crude oil will be strong. Given increased regulatory emphasis on wind and solar power generation, and potential greenhouse gas legislation that may limit construction of new coal-fired power plants, natural gas will be the fuel of choice for power generation. Additional gas-fired peaking resources will also be required to provide back-up supply for renewable technologies.

We will continue efforts to develop additional markets for our coal production, including the development of additional power plants at our mine site. Nearly 50% of all electricity generated in the United States is currently supplied from coal-fired plants. It will take decades and significant expense before this generation can be replaced with alternative technologies. As a result, coal-fired resources will remain a necessary component of the nation's electric supply for the foreseeable future. Potential greenhouse gas legislation may limit construction of new conventional coal-fired power plants, but technologies such as carbon capture and sequestration should provide for the long-term economic use of coal. We are investigating the possible deployment of these technologies at our mine site in Wyoming.

We divested of seven IPP plants in 2008 because we were able to capture significant value for shareholders, but we have not exited the non-regulated power generation business. We have expertise in permitting, constructing and operating power generation facilities. These skills, combined with our understanding of electric resource planning and regulatory procedures, provide a significant opportunity for us to add long-term shareholder value. We intend to grow our non-regulated power generation business by continuing to focus on long-term contractual relationships with other load-serving utilities. This was exemplified with the September 2009 announcement that our non-regulated generation subsidiary was selected as the successful bidder to build 200 MWs of combined-cycle gas fired power generation to provide energy and capacity to our Colorado Electric subsidiary, through a 20-year power purchase agreement.

The expertise of our energy marketing business should provide continued long-term profitability through a risk-managed and disciplined approach to producer services, origination, storage, transportation and proprietary marketing strategies. We will also continue to utilize our marketing expertise to enhance the value of our other energy assets, particularly our fuel and power generation assets.

We operate our lines of business as Utilities and Non-regulated Energy Groups. The Utilities Group consists of regulated electric and natural gas utility assets and services. The Non-regulated Energy Group consists of fuel production, mid-stream assets, power generation facilities and energy marketing.

The following are key elements of our business strategy:

- Complete the integration of the five utility properties acquired in the July 2008 Aquila Transaction, focusing on the achievement of operating efficiencies and cost reductions;
- Provide stable long-term rates for customers and increase earnings by efficiently planning, constructing and operating rate-base power generation facilities needed to serve our electric utilities;
- Proactively integrate alternative and renewable energy into our utility energy supply while mitigating and remaining mindful of customer rate impacts;
- Expand utility operations through selective acquisitions of electric and gas utilities consistent with our regional focus and strategic advantages;
- Build and maintain strong relationships with wholesale power customers of both our utilities and non-regulated power generation businesses;
- Selectively grow our non-regulated power generation business in targeted regional markets by developing assets and selling most of the capacity and energy production through mid- and long-term contracts primarily to load-serving utilities;
- Exploit our fuel cost advantages and our operating and marketing expertise to produce and sell power at attractive margins;
- Grow our reserves and increase our production of natural gas and crude oil in a cost-effective manner;
- Opportunistically expand our energy marketing operations including producer and end-use origination services and, as warranted by market conditions, natural gas and crude oil storage and transportation opportunities;
- Diligently manage the credit, price and operational risks inherent in buying and selling energy commodities; and
- Maintain an investment grade credit rating and ready access to debt and equity capital markets.

Complete the integration of the five utility properties acquired in the 2008 Aquila Transaction, focusing on the achievement of operating efficiencies and cost reductions. The July 14, 2008 acquisition of five utility properties in four states from Aquila significantly expanded our regional presence and the size and scope of our utility operations. The expanded utility operations enhanced our ability to serve customers and communities, and to build long-term value for our shareholders. As we have during 2009, we will continue to work diligently in 2010 to complete the integration of operating system consolidations and establish more efficient processes so that we have a unified scalable platform ready for additional growth. By standardizing processes, centralizing purchasing and inventory, and utilizing common computer systems and processes for customer service, accounting, human resources and operations, it will be possible to reduce costs and improve our operating efficiency.

Provide stable long-term rates for customers and increase earnings by efficiently planning, constructing and operating rate-base power generation facilities needed to serve our electric utilities. Our Company began as a vertically integrated electric utility, and this business model remains a core strength and strategy today, as we invest in and operate efficient power generation resources to cost effectively transmit and distribute electricity to our customers. We provide power at reasonable and stable rates to our customers, and earn competitive returns for our investors. Rate-based generation assets offer several advantages for consumers, regulators and investors. First, since the generating assets are included in the utility rate base and reviewed and approved by government authorities, customer rates are more stable than if the power was purchased from the open market through wholesale contracts that are renegotiated over time. Second, regulators participate in a planning process where long-term investments are designed to match long-term energy demand. Third, investors are assured that a long-term, reasonable, stable rate of return may be earned on their investment. A lower risk profile may also improve credit ratings which, in turn, can benefit both consumers and investors by lowering our cost of capital.

Examples of our progress include the January 2008 completion of Wygen II to serve the customers of Cheyenne Light and the ongoing construction of Wygen III, projected to be completed in April 2010, to serve the customers of Black Hills Power. During 2009, our Colorado Electric subsidiary completed a comprehensive resource planning process, through which we received approval to construct two gas-fired power plants representing approximately 180 MW, as rate base assets to serve the customers of Colorado Electric. The projected commercial operation date for the plants is January 1, 2012.

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

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

- In states such as South Dakota and Wyoming that currently have no legislative mandate on the use of renewable energy, we have proactively integrated cost-effective renewable energy into our generation supply based upon our expectation that there will be mandatory renewable energy standards in the future. For example, under two 20-year PPAs we purchase a total of 60 MW of wind energy from wind farms located near Cheyenne, Wyoming for use at Black Hills Power and Cheyenne Light;

- Colorado and Montana have legislative mandates regarding the use of renewable energy, therefore we aggressively pursue cost-effective initiatives with the regulators that will allow us to meet our renewable energy requirements. In Colorado for instance, we filed an electric resource plan that includes enough renewable energy additions and greenhouse gas emission reductions to permit us to satisfy both (i) the State's requirement that 20% of a utility's distributed energy must be supplied by renewable energy resources by 2020, and (ii) the governor's executive order that requires a 20% reduction in carbon dioxide emissions by 2020; and

- In all states in which we conduct electric utility operations, we are exploring other potential biomass, solar and wind energy projects and evaluating other potential wind generator sites, particularly sites located near our utility service territories.

Using reasonable assumptions, we have also carefully evaluated our coal-fired generating facilities and the potential future economic impact of a carbon tax or cap-and-trade regime intended to reduce CO2 emissions. For customers in states without renewable or CO2 mandates, such as South Dakota and Wyoming, we believe it is in our utility customers' long-term interest to construct new mine-mouth, coal-fired generating facilities, such as our Wygen II generation facility (completed in January 2008) and our Wygen III generation facility (expected to be completed on April 1, 2010). Constructing these state-of-the-art, cost-efficient, coal-fired facilities allows us to plan for the future retirement of older, less efficient plants with higher emissions and keep rates reasonable for customers. In addition, we are actively evaluating alternative coal-fired generation technologies, including IGCC and carbon capture and sequestration, though both appear cost prohibitive in the near term. These technologies may become cost effective in the future if the cost of CO2 emissions reaches sufficiently high levels or further technological advancements reduce the costs of those technologies. The location of our coal mine and power plant complex in the Powder River Basin of Wyoming provides key strategic advantages for carbon capture and sequestration projects, such as readily available saline aquifers for the injection and sequestration of CO2, as well as a potential CO2 market for use in enhanced oil recovery projects. Additionally, over the past two years, the Wyoming legislature has been proactive in passing legislation to address pore space ownership, injection regulations and other legal issues associated with the underground sequestration of CO2.

Expand utility operations through selective acquisitions of electric and gas utilities consistent with our regional focus and strategic advantages. For nearly 127 years we have provided reliable utility services, delivering quality and value to our customers. Our tradition of accomplishment supports efforts to expand our utility operations into other markets, most likely in areas that permit us to take advantage of our intrinsic competitive advantages, such as baseload power generation, system reliability, superior customer service, community involvement and a relationship-based approach to regulatory matters. The 2005 acquisition of Cheyenne Light and the 2008 Aquila Transaction are examples of such expansion efforts. Utility operations also enhance other important business development, including gas transmission pipelines and storage infrastructure, which could promote other non-regulated energy operations. Utility operations can contribute substantially to the stability of our long-term cash flows, earnings and dividend policy.

Although we do not expect to make any significant utility acquisitions in 2010, some industry experts believe that the current financial turmoil and economic recession may produce opportunities for healthy utility companies to acquire utility assets and operations of less creditworthy companies upon attractive terms and conditions. We would expect to consider such opportunities if we believe they would further our long-term strategy and help maximize shareholder value.

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

Selectively grow our non-regulated power generation business in targeted Western markets by developing assets and selling most of the capacity and energy production through mid- and long-term contracts primarily to load-serving utilities. In late 2007, we initiated an evaluation of the merits of divesting certain power generation assets. That strategic review resulted in the mid-2008 divestiture of seven IPP plants for a total of $840 million. While much of our recent power plant development has been for our regulated utilities, we intend to continue to expand our non-regulated power generation business by developing and operating power plants in regional markets based on prevailing supply and demand fundamentals in a manner that complements our existing fuel assets and marketing capabilities. We intend to grow this business through a combination of the development of new power generation facilities and disciplined acquisitions primarily in the western region where our detailed knowledge of market and electric transmission fundamentals provides us a competitive advantage, and, consequently increases our ability to earn attractive returns. We expect to prioritize small-scale facilities that serve incremental growth, and are typically easier to permit and construct than large-scale generation projects.

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

With respect to our current power sale agreements, two of our long-term power contracts provide for the sale of capacity and energy to Cheyenne Light from our Gillette CT and Wygen I plants. The Gillette CT contract expires in 2011, and as part of our integrated resource planning efforts, the company is evaluating a potential extension of the contract. The Wygen I contract was extended during 2009 and now expires in 2022.

Exploit our fuel cost advantages and our operating and marketing expertise to produce and sell power at attractive margins. We expect to selectively expand our portfolio of power plants which have relatively low marginal costs of producing energy and related products and services. We intend to utilize a competitive power production strategy, together with access to coal and natural gas reserves, to be competitive as a power generator. Competitive production costs can result from a variety of factors, including low fuel costs, efficiency in converting fuel into energy, and low per unit operation and maintenance costs. In addition, we typically operate our plants with high levels of availability, as compared to industry benchmarks. We aggressively manage each of these factors with the goal of achieving low production costs.

One of our primary competitive advantages is our WRDC coal mine, which is located in reasonably close proximity to our electric utility service territories. We leverage this competitive advantage by building additional state-of-the-art mine-mouth coal-fired generating capacity, which allows us to substantially eliminate fuel transportation and storage costs. This strengthens our position as a low-cost producer because transportation costs often represent the largest component of the delivered cost of coal for many other utilities.

Grow our reserves and increase our production of natural gas and crude oil in a cost-effective manner. Our strategy is to cost-effectively grow our reserves and increase our production of natural gas and crude oil through both organic growth and acquisitions. While consistent growth remains our objective, we realize the necessity of managing for value over managing for growth and intend to be appropriately responsive to market conditions. Growth in our core areas in the Rocky Mountain region is a focus that we must balance with opportunities in plays or basins which are new to us. In the short-term, growth plans are negatively impacted by the current economic crisis, and low natural gas and crude oil prices. Over the long term, however, we believe that demand will lead to higher product prices and opportunity for growth. Specifically, we plan to:

- Primarily focus on lower-risk development and exploratory drilling, preferably where we can serve as the operator;

- Participate on a non-operated basis with other operators to gain exposure to additional plays and producing basins;

- Focus on various plays in the Rocky Mountain region, where we can more easily integrate with our existing oil and natural gas operations as well as our fuel marketing and/or power generation activities;

- Support the future capital requirements of our drilling program by stabilizing cash flows with a hedging program that mitigates commodity price risk for a substantial portion of our established production for up to two years in the future; and

- Enhance our oil and gas production activities with the construction or acquisition of mid-stream gathering, compression and treating facilities in a manner that maximizes the economic value of our operations.

Opportunistically expand our energy marketing operations including producer and end-use origination services and, as warranted by market conditions, natural gas and crude oil storage and transportation opportunities. Our energy marketing business seeks to provide services to producers and end-users of natural gas and crude oil and to capitalize on market volatility by employing storage, transportation and proprietary trading strategies. 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.

Diligently manage the credit, price and operational risks inherent in buying and selling energy commodities. All of our operations require effective management of counterparty credit risk. We mitigate this risk by conducting business with a diverse group of creditworthy counterparties. In certain cases where creditworthiness merits security, we require prepayment, secured letters of credit or other forms of financial collateral. We establish counterparty credit limits and employ continuous credit monitoring, with regular review of compliance under our credit policy by our Executive Credit Committee. Our oil and gas, power generation and energy marketing operations require effective management of price and operational risks related to adverse changes in commodity prices and the volatility and liquidity of the commodity markets. To mitigate these risks, we implemented risk management policies and procedures, particularly for our marketing operations. Our oversight committees monitor compliance with these policies. We also limit exposure to energy marketing risks by maintaining a credit facility separate from our corporate credit facility. We experienced very limited counterparty credit losses in 2009 despite the economic turmoil.

Maintain an investment grade credit rating and ready access to debt and equity capital markets. Access to capital will be critical to our future success. We will require access to the capital markets to fund our planned capital investments or, when possible, to make strategic acquisitions that prudently grow our businesses. Our access to adequate and cost-effective financing depends upon our ability to maintain our investment grade issuer credit rating.

In late 2008 and throughout 2009, disruption in worldwide capital markets substantially reduced liquidity in the debt capital markets and caused significant write-offs in the financial services sector, the re-pricing of credit risk, and the failure of certain financial institutions. Despite actions of the United States government, these events contributed to a general economic decline that is materially and adversely impacting the broader financial and credit markets, and reducing the availability of debt and equity capital. Our acquisition of additional utility properties in 2008, combined with the divestiture of seven IPP plants, reduced our overall corporate risk profile. Even so, our access to capital markets was impacted by the conditions described above, particularly during the fourth quarter of 2008 and the first quarter of 2009.

Notwithstanding these adverse market conditions, in 2009 we completed several key financings on reasonable terms, including a $250 million senior unsecured corporate bond offering, a $300 million committed stand-alone credit facility for our energy marketing subsidiary, a $180 million first mortgage bond financing for Black Hills Power, and a $120 million project financing for our Wygen I and Gillette CT power plants.

Prospective Information

We expect to generate long-term growth through the expansion of integrated, balanced and diverse energy operations. We recognize that sustained growth requires near continual capital deployment. As capital market conditions improved in 2009, we were able to complete three key long-term debt financings and we are confident in our ability to obtain additional financing to continue our growth plans. We will remain focused on managing our operations cautiously and maintaining our overall liquidity to meet our operating, capital and financing needs, as well as executing our long-term strategic plan.

Utilities Group

The Utilities Group successfully completed a full year of operations including those operations purchased in the Aquila Transaction. Post-close integration activities are being executed so that our workforces and systems will be combined to establish a growth platform that delivers value to our shareholders. During 2009, the Utilities Group completed conversion to a single customer information system which unified our customer service and billing processes. We continue to work to unify our performance management and compensation systems, outage management, inventory management and accounting systems. We anticipate these process improvements will be completed in 2010.

Electric Utilities

Business at Black Hills Power remained relatively strong in 2009. We continue construction of the Wygen III power plant, which is planned for commercial operation by April 2010. Black Hills Power owns 75% of the facility with MDU purchasing a 25% ownership interest in the facility in April 2009. Beginning January 1, 2009, we benefited from an increase in transmission rates resulting from a FERC transmission rate case. The rate structure also includes a formula approach to rates that allows us to recover our capital investment as the capital is placed in service on the related transmission infrastructure. To accommodate both the load growth within the region and the addition of Wygen III, additional transmission infrastructure is planned over the next several years.

During 2009, Black Hills Power filed two rate cases. One with the SDPUC and the other with WPSC, requesting an electric revenue increase to recover costs associated with Wygen III and other generation, transmission and distribution assets and increased operating expenses. A $32.0 million, or approximately 26.6%, increase in annual utility revenues was requested in South Dakota and the new rates are expected to be in effect on or around April 1, 2010. The request for our Wyoming customers is a $3.8 million, or approximately 38.95%, increase in annual utility revenues and new rates are anticipated to be effective on or around July 1, 2010, although recovery could be delayed until August 2010 as part of the regulatory process. The proposed rate increases are subject to approval by the applicable state commissions.

We are focused on Colorado Electric's Energy Resource Plan and during 2009, Colorado Electric received approval from the CPUC to build power generation facilities representing approximately 180 MW. These generation facilities are part of a plan to replace the capacity and energy supplied under a PPA with PSCo that currently supplies approximately 75% of Colorado Electric's annual energy and capacity needs and expires at the end of 2011. The addition of these plants to our utility rate base will have a significant positive impact on our financial results. We filed a normal rate case for Colorado Electric in January 2010 to recover increased costs and investments made since the last rate case was filed and plan a future filing pertinent to the new generation and transmission assets as they are ready to begin serving customers.

The remaining capacity and energy needed for Colorado Electric was acquired through a competitive bidding process including other power producers. Our Power Generation segment participated in this bidding process, and in

September 2009, our Power Generation segment was awarded the bid to provide 200 MW of capacity and energy to Colorado Electric through a 20-year PPA.

Gas Utilities

Our regulated Gas Utilities are focused on the continued investment in our gas distribution network and related technology such as automated meter reading and mobile data terminals. As further described in our Utilities Group "Regulation and Rates" discussion within Items 1 and 2 - Business and Properties of this Annual Report on Form 10-K, we received approval for rate increases and specific cost recoveries for Iowa Gas, Colorado Gas and Kansas Gas in 2009. We also filed a rate request for Nebraska Gas of $12.1 million to be effective subject to refund on March 1, 2010. As part of the KCC approval of the Aquila Transaction, the KCC implemented a moratorium on filing for a general rate increase until 2011 for Kansas Gas. We continually monitor our investments and costs of operations in all states to determine when additional rate case or other rate filings will be necessary.

Non-regulated Energy Group

Power Generation

During January 2009, we completed the sale of a 23.5% interest in Wygen I to MEAN for $51.0 million. We recognized a gain on the sale of approximately $16.9 million after-tax. Concurrently with this sale, we also terminated a 10-year power purchase contract under which MEAN was obligated to buy 20 MW of power and capacity from Wygen I. The decreased revenues associated with the terminated agreement will be partially replaced by agreements under which MEAN will pay for costs associated with administrative services, plant operations, site leases and coal supplied by our Coal Mining operation.

Our Power Generation segment was awarded the bid to provide 200 MW of power to our Colorado Electric subsidiary through a 20-year PPA. The 200 MW natural gas-fired electric generation facilities will be built in Colorado and are expected to be completed by the end of 2011.

We plan to continue evaluating opportunities to bid on the construction of generation resources, both new and existing, for other regional electric utilities for their energy and capacity needs.

Coal Mining

Production from the Coal Mining segment primarily serves mine-mouth generation plants and select regional customers with long-term fuel needs. Increased demand will come from additional mine-mouth generation either currently being constructed or in various stages of development. Total annual production is estimated to be approximately 6.6 million tons in 2010.

Oil and Gas

During 2009, we limited our development capital due to low oil and gas prices. Although we are focused on growing our oil and gas production through development of existing acreage and limited acquisitions depending on economic and industry conditions, our decision to shut-in production at properties with the highest operating costs and limit development capital due to low prices will continue into 2010. During 2010, we expect to limit our development capital to no more than the cash flows produced by our oil and gas properties. The current economic conditions will be particularly challenging since low commodity prices make many of our development drilling sites uneconomical, which could further reduce our development capital expenditures. The lower development capital expenditures will lead to lower production levels due to the natural production decline of existing wells.

In the first quarter of 2009, we recorded a $27.8 million after-tax ceiling test impairment charge to our oil and gas properties. For reporting periods ending on or after December 31, 2009, the SEC adopted new reporting and accounting requirements for oil and gas companies which changed the way we test for partial ceiling test impairments. Key revisions include changes to the pricing used to determine reserves to a 12-month average price. This change does not alleviate the potential for future impairments, but currently none are anticipated.

Energy Marketing

We have a strong marketing portfolio with a significant amount of optionality that can provide opportunities to create economic value over the next several years. While we expect to derive earnings from these contracts over many years, the required methods of accounting for these transactions could result in additional earnings volatility during the term of these contracts. Our 2009 earnings were negatively impacted as market conditions prevented us from replacing the positive mark-to-market value of contracts that settled during the year.

During 2008 and continuing into 2009, there was a significant contraction in the availability of capital. Despite these challenges, we entered into an agreement for a committed Enserco Credit Facility on May 8, 2009. Impacting results in 2009, was our decision beginning in late 2008 and continuing into mid-2009 to conduct our Enserco business operation in a manner to preserve overall liquidity, which included minimizing utilization of the existing non-committed Enserco Credit Facility until the new committed facility was finalized. This constraint on capital restricted Enserco's ability to take advantage of favorable transactions that might have been available in the marketplace in the first half of 2009. The Credit Facility relieves these constraints for Enserco's operations in 2010.

Corporate

During 2009, we completed several long-term financings including a $250.0 million senior unsecured bond offering which was used along with the Corporate Credit Facility to repay the Acquisition Facility; a $180.0 million first mortgage bond issuance at Black Hills Power; a $120.0 million project financing at Black Hills Wyoming; and refinancing of two Industrial Development Revenue Bonds at Cheyenne Light. We continue to work toward integration and unification of our processes and systems. In 2009, we completed conversion of our customer information system, implemented new performance management and compensation programs, commenced unification of our employee benefits, and continued efforts on converting our financial, outage management, utility engineering, procurement and inventory, and work management systems.

As of December 31, 2009, we had interest rate swaps with a notional amount of $250.0 million, which do not currently qualify for "hedge accounting" treatment provided by accounting standards for derivatives and hedges. Accordingly, all mark-to-market adjustments on these swaps are recorded through the income statement. As of December 31, 2009, the mark-to-market value of these swaps was a liability of $38.8 million. In 2009, we recorded an unrealized mark-to-market after-tax gain of $36.2 million on these swaps. Fluctuations in interest rates create volatility in the fair value of these swaps which will likely have an impact on our 2010 earnings as we record the associated unrealized mark-to-market gains or losses within our income statement. These swaps are for terms of nine and nineteen years and have amended mandatory early termination dates ranging from December 15, 2010 to December 29, 2010. We have continued to maintain these swaps in anticipation of our upcoming financing needs, particularly as they relate to our planned capital requirements to build gas-fired power generation facilities to serve our Colorado Electric customers, and because of our upcoming holding company debt maturities, which are $225 million and $250 million in years 2013 and 2014, respectively. Alternatively, we may choose to cash settle these swaps at their fair value prior to their mandatory early termination dates, or unless these dates are extended, we will cash settle these swaps for an amount equal to their fair value on the termination dates.

Results of Operations

Executive Summary and Overview

		2009		2008		2007
				(in thousands)		
Revenue:						
Utilities	$	1,100,204	$	749,250	$	301,514
Non-regulated Energy		169,374		256,540		273,324
	$	1,269,578	$	1,005,790	$	574,838

	2009	2008	2007
		(in thousands)	
Income (loss) from continuing operations:			
Utilities	$57,071	$43,904	$31,633
Non-regulated Energy	579	(23,345)	49,897
Corporate	21,106	(72,596)	(5,872)
	$78,756	$(52,037)	$75,658

	2009	2008	2007
		(in thousands)	
Net income available for common stock:			
Utilities	$57,071	$43,904	$31,633
Non-regulated Energy	1,938	(5,312)	73,089
Corporate	22,546	66,488	(5,950)
	$81,555	$105,080	$98,772

2009 Compared to 2008

Income from continuing operations was $78.8 mill