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;

- 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.

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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

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

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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

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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, SO2, NOx, mercury and particulate matter. In addition, CO2 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 SO2 allowance trading program as part of the federal acid rain program. Each allowance gives the owner the right to emit one ton of SO2, 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 SO2 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 SO2 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 SO2, NOx, 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.

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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.

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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.

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 CO2 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, CO2-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.

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 (in thousands)	2007
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 (in thousands)	2007
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 (in thousands)	2007
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 million, or $2.04 per share, in 2009 compared to a loss from continuing operations of $52.0 million, or $1.37 per share for 2008. The 2009 income from continuing operations includes a gain on sale of $16.9 million after-tax of a 23.5% ownership interest in the Wygen I plant; a $36.2 million after-tax non-cash mark-to-market gain on certain interest rate swaps; and a $27.8 million after-tax impact of a non-cash ceiling test impairment at our Oil and Gas segment. Results also reflect a full year of operations for the utilities purchased in the Aquila Transaction. The 2008 loss from continuing operations includes a $61.4 million after-tax non-cash mark-to-market loss on certain interest rate swaps; and a $59.0 million after-tax loss of a non-cash ceiling test impairment at our Oil and Gas segment.

Net income available for common stock was $81.6 million, or $2.11 per share, in 2009 compared to $105.1 million or $2.75 per share for 2008. In addition to the items mentioned in income from continuing operations, the 2008 net income includes $157.2 million after-tax income from discontinued operations for the sale of seven IPP properties. Return on common stock equity in 2009 and 2008 was 7.6% and 10.4%, respectively.

Highlights of our business groups are as follows:

Utilities Group

The Utilities Group's income from continuing operations for 2009 was $57.1 million in 2009, compared to $43.9 million in 2008. Income from continuing operations at the Electric Utilities were impacted $7.6 million by low off-system sales margins due to low commodity prices while income from continuing operations at the Gas Utilities was strong due to favorable weather. In addition, 2009 Utilities Group highlights include the following:

- Construction of the Wygen III generation facility project continued in 2009 and is scheduled to begin commercial operation by April 1, 2010. A 25% ownership interest in this generation facility was sold in April 2009. AFUDC increased $4.0 million related to this construction.

- Colorado Electric continued plans and purchases to construct 180 MW of utility-owned, gas-fired generation. AFUDC increased $1.2 million due to this construction.

- Black Hills Power received approval from FERC for a $3.8 million increase in annual transmission revenues.

- Colorado Gas received approval from the CPUC for a $1.4 million increase in annual revenues, effective on April 1, 2009.

- Iowa Gas received approval from the IPUB for a $10.8 million increase in annual revenues, with an effective date of July 31, 2009.

- Black Hills Power completed a first mortgage bond for $180.0 million. The bonds carry an interest rate of 6.125% and mature in November 2039. Interest from this debt and other debt transactions increased interest expense $12.7 million.

- We completed the retirement of $383.0 million of borrowings on our bridge acquisition facility which was used to finance the Aquila Transaction on July 14, 2008.

- We completed our first full year of operations for Colorado Electric and the Gas Utilities acquired in the Aquila Transaction.

Non-Regulated Energy Group

Income from continuing operations was $0.6 million in 2009 for the Non-regulated Group compared to a loss from continuing operations of $23.3 million in 2008. Our Energy Marketing and Oil and Gas segments were impacted significantly by low commodity prices. In addition, 2009 Non-regulated Energy Group highlights include the following:

- Oil and Gas recorded a $43.3 million non-cash ceiling test impairment loss in 2009 compared to a $91.8 million ceiling test impairment loss in 2008.

- Power Generation's improved earnings reflect a gain of $26.0 million for the sale of a 23.5% ownership interest in the Wygen I power generation facility to MEAN.

- Our Coal Mining segment executed a site lease agreement with the owners of the currently under construction Wygen III plant increasing earnings $2.9 million for rental revenue in 2009.

- Energy Marketing completed a $300.0 million committed stand-alone credit facility in May 2009, to replace its previously uncommitted $300.0 million credit facility.

- Black Hills Wyoming completed $120.0 million in project financing in December 2009. The loan matures in December 2016 with an interest rate of LIBOR plus 3.25% per annum.

- Black Hills Colorado IPP was selected to provide power to Colorado Electric and began planning and purchasing to build 200 MW of natural gas-fired electric generation to sell to Colorado Electric through a 20-year PPA.

Corporate Segment

- We recognized a mark-to-market gain related to certain interest rate swaps of $55.7 million in 2009 compared to a $94.4 million loss recognized in 2008.

- We completed a $250.0 million public offering of senior notes due in 2014 in May 2009. The notes were priced at par and carry an interest rate of 9%.

2008 Compared to 2007

Consolidated loss from continuing operations for 2008 was $52.0 million, or $1.37 per share, compared to earnings of $75.7 million, or $2.02 per share, in 2007. Income from discontinued operations was $157.2 million, or $4.12 per share, compared to income of $23.5 million, or $0.63 per share in 2007 and includes a $139.7 million gain on the sale of the operating assets from the IPP Transaction. Return on average common stock equity in 2008 and 2007 was 10.4% and 11.2%, respectively.

The Utilities Group income from continuing operations increased $12.3 million in 2008 compared to 2007. 2008 results include the earnings from the operations of the five utilities acquired in the Aquila Transaction subsequent to the July 14, 2008 acquisition date. Earnings from continuing operations from the regulated Electric Utilities increased $8.0 million primarily due to an increase in retail rates and increased electricity sold to retail customers. Earnings from continuing operations from the regulated Gas Utilities were $4.2 million for the period July 14, 2008 through December 31, 2008.

The Non-regulated Energy Group's loss from continuing operations was $23.3 million in 2008, compared to earnings of $49.9 million in 2007, primarily due to a $59.0 million after-tax ceiling test impairment at the Oil and Gas segment and lower earnings from Energy Marketing of $14.5 million. Partially offsetting these decreases was an increase in Power Generation earnings of $6.6 million, which includes the impact of increased earnings from investment partnerships and lower indirect corporate costs related to the IPP Transaction.

Consolidated revenues for 2008 were $431.0 million higher than 2007 primarily due to the addition of the utilities acquired in the Aquila Transaction and increased Oil and Gas and Coal Mining revenues, partially offset by decreased revenues from Energy Marketing.

Consolidated operating expenses for 2008 increased $500.8 million compared to 2007. Operating expenses were impacted by the $91.8 million pre-tax ceiling test impairment at the Oil and Gas segment, increased overburden removal costs at the coal mine, additional operating costs from the Wygen II plant placed into service in January, 2008 and the addition of operating costs of the acquired utilities since their acquisition date.

Income from continuing operations was also impacted by a $94.4 million pre-tax mark-to-market loss related to interest rate swaps no longer designated as hedges for accounting purposes.

A discussion of operating results from our business segments follows.

The following business group and segment information does not include discontinued operations or intercompany eliminations. Accordingly, 2009, 2008 and 2007 information has been revised to remove information related to operations that were discontinued. Amounts are presented on a pre-tax basis unless otherwise indicated.

Utilities Group

Regulated Electric Utilities

Operating results for the years ended December 31, for the regulated Electric Utilities are as follows (in thousands):

	2009	2008 (1)	2007
Revenue - electric	$485,152	$425,123	$270,943
Revenue - gas	35,613	48,296	32,468
Total revenue	520,765	473,419	303,411
Fuel and purchased power - electric	260,150	222,826	133,289
Purchased gas	20,859	33,735	22,649
Total fuel and purchased power	281,009	256,561	155,938
Gross margin - electric	225,002	202,297	137,654
Gross margin - gas	14,754	14,561	9,819
Total gross margin	239,756	216,858	147,473
Operating expenses	168,788	138,992	94,161
Operating income	70,968	77,866	53,312
Interest expense, net	33,012	23,294	13,730
Other income	(7,869)	(3,984)	(4,877)
Income tax expense	13,126	18,882	12,826
Income from continuing operations and net income	$32,699	$39,674	$31,633

(1) 2008 results include the operations of Colorado Electric acquired on July 14, 2008.

	2009	2008	2007
Regulated power plant fleet availability:			
Coal-fired plants	92.1 %	93.7 %	95.4 %
Other plants	96.9 %	91.4 %	99.4 %
Total availability	94.0 %	92.8 %	97.2 %

2009 Compared to 2008

2009 results include a full year of operations at Colorado Electric, which was acquired on July 14, 2008.

Income from continuing operations was $32.7 million after-tax in 2009 compared to $39.7 million after-tax in 2008 primarily due to:

- A $7.6 million decrease in margins from off-system sales reflecting the lower margins available in the current low energy price environment; and

- A $9.7 million increase in net interest expense primarily due to additional debt associated with the acquisition of Colorado Electric, additional long-term project debt at Black Hills Power, and inter-segment debt restructuring at Colorado Electric, partially offset by AFUDC-borrowed.

Partially offsetting these were:

- A $6.5 million increase in other margins primarily due to an increase in transmission rates effective January 1, 2009 at Black Hills Power; and

- Increased other income primarily due to an increase in AFUDC-equity of $2.1 million from the construction of Wygen III in 2009.

2008 Compared to 2007

2008 results include a partial year of operations at Colorado Electric, which was acquired on July 14, 2008.

Income from continuing operations was $39.7 million after-tax in 2008 compared to $31.6 million after-tax in 2007, primarily due to:

- An increase in earnings of approximately $8.0 million primarily due to the impact of a rate increase at Cheyenne Light effective January 1, 2008; and

- A 34% increase in electric MWh sales to retail customers, primarily due to the acquisition of Colorado Electric.

Partially offsetting these were:

- Increased plant maintenance costs and depreciation expense of approximately $11.1 million associated with the Wygen II plant placed into service January 1, 2008; and

- Lower AFUDC compared to 2007.

Regulated Gas Utilities

Operating results for the years ended December 31, for the regulated Gas Utilities are as follows (in thousands):

	2009	For the Period July 14, 2008 to December 31, 2008
Revenue:		
Natural gas - regulated	$553,576	$261,887
Other - non-regulated	26,736	15,189
Total sales	580,312	277,076
Cost of sales:		
Natural gas - regulated	356,623	180,556
Other - non-regulated	15,093	11,294
Total cost of sales	371,716	191,850
Gross margin:		
Natural gas – regulated	196,953	81,331
Other non-regulated	11,643	3,895
Total gross margin	208,596	85,226
Operating expenses	153,386	70,338
Operating income	55,210	14,888
Interest expense, net	17,100	8,125
Other expense	285	86
Income tax expense	13,453	2,447
Income from continuing operations and net income	$24,372	$4,230

The regulated Gas Utilities located in Colorado, Nebraska, Iowa and Kansas were acquired on July 14, 2008. Income from continuing operations was $24.4 million in 2009, compared to $4.2 million in 2008. The increase was primarily due to a full year of regulated Gas Utilities operation in 2009 compared to the partial year in 2008. Natural gas demand is typically higher in the first and fourth quarters as gas is used for residential and commercial heating. The regulated Gas Utilities have GCAs that allow them to pass through the cost of gas to customers. For this reason, we believe gross margins are a more useful performance measure than revenues as fluctuations in the cost of gas are passed through to revenues.

In addition to a full year of operations at the Gas Utilities, results were impacted by favorable weather as well as rate increases from general rate cases in Colorado ($1.4 million annual increase effective April 1, 2009), general rate cases in Iowa ($10.8 million annual increase effective July 27, 2009), and from cost tracking riders in Kansas ($0.5 million annual increase effective September 14, 2009).

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Non-regulated Energy Group

Oil and Gas

Oil and Gas operating results were as follows (in thousands):

	2009	2008	2007
Revenue	$70,684	$106,347	$101,522
Operating expenses(a)	69,904	85,753	76,085
Impairment of long-lived assets	43,301	91,782	-
Operating (loss) income	(42,521)	(71,188)	25,437
Interest expense, net	4,673	5,092	8,657
Other income	(350)	(611)	(1,108)
Income tax (benefit) expense	(21,016)	(26,001)	5,182
Income (loss) from continuing operations and net income	$(25,828)	$(49,668)	$12,706

(a) Operating expenses included a $43.3 million and $91.8 million ceiling test impairment charge in 2009 and 2008, respectively.

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

	Crude Oil and Natural Gas Production		
	2009	2008	2007
Bbls of oil sold	366,000	387,400	409,040
Mcf of natural gas sold	10,266,900	11,209,600	12,172,400
Mcf equivalent sales	12,462,900	13,534,000	14,626,640

	Average Price Received(a)		
	2009	2008	2007
Gas/Mcf(b)	$4.58 (c)	$6.24 (c)	$6.19
Oil/Bbl	$59.19	$79.35	$60.29

(a) Net of hedge settlement gains/losses
(b) Exclusive of gas liquids
(c) Does not include the negative revenue impact of a $1.2 million and $2.1 million royalty settlement accrual for 2009 and 2008, respectively, resulting in a $0.13/Mcf and $0.20/Mcf price impact

	2009	2008	2007
Average production cost (per Mcfe):			
LOE	$1.22	$1.33	$0.98

Production taxes	0.46	0.91	0.70
Total	$1.68	$2.24	$1.68

	Depletion		
	2009	2008	2007
Depletion expense/Mcfe*	$2.16	$2.68	$2.21

*The average depletion rate per Mcfe is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented. The 2009 rate was particularly impacted by a lower asset base as a result of previous asset impairment charges. This impact was partially offset by persistent low product prices during the year, which resulted in lower oil and gas reserve quantities.

The following is a summary of annual average operating expenses per Mcfe at December 31:

	2009			2008			2007		
	LOE	Gathering Compression and Processing	Total	LOE	Gathering Compression and Processing	Total	LOE	Gathering Compression and Processing	Total
New Mexico	$1.29	$ 0.30	$1.59	$1.48	$ 0.29	$1.77	$1.04	$ 0.31	$1.35
Colorado	1.06	0.41	1.47	1.29	0.77	2.06	0.95	0.79	1.74
Wyoming	1.42	-	1.42	1.55	-	1.55	1.19	-	1.19
All other properties	0.91	0.26	1.17	0.89	0.12	1.01	0.71	0.17	0.88
Total	$1.22	$ 0.22	$1.44	$1.33	$ 0.22	$1.55	$0.98	$ 0.23	$1.21

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

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

	2009	2008	2007
Bbls of oil (in thousands)	5,274	5,185	5,807
MMcf of natural gas	87,660	154,432	172,964
Total MMcfe	119,304	185,542	207,806

Reserves are based on reports prepared by an independent consulting and engineering firm. The reports were prepared by Cawley, Gillespie & Associates, Inc., an independent engineering company. Reserves were determined using SEC-defined product prices. Such reserve estimates are inherently imprecise and may be subject to revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. The current estimate takes into account 2009 production of approximately 11.9 Bcfe, additions from extensions, discoveries and acquisitions of 3.5 Bcfe and negative revisions to previous estimates of 57.8 Bcfe, including approximately 54.9 Bcfe due to lower product prices.

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

	2009*		2008		2007	
	Oil	Gas	Oil	Gas	Oil	Gas
NYMEX prices	$61.18	$3.87	$44.60	$5.71	$95.98	$6.80
Well-head reserve prices	$53.59	$2.52	$32.74	$4.44	$83.23	$5.88

* On December 31, 2008, the SEC issued final rules amending its oil and gas reserve reporting requirements effective for years ending on or after December 31, 2009. The final rule changed the use of prices at the end of each reporting period to an average of the first day of the month for the preceding twelve months held constant for the life of production. Previously, the rule required the use of the spot price on the last day of the reporting period, held constant for the life of production.

2009 Compared to 2008

Loss from continuing operations was $25.8 million after-tax compared to a loss of $49.7 million after-tax in the prior year, primarily due to:

- A $27.8 million after-tax non-cash ceiling test impairment charge was taken during the first quarter of 2009. The write-down in the net carrying value of our natural gas and crude oil properties resulted from low March 31, 2009 quarter-end natural gas prices for the commodities. The write-down of gas and oil properties was based on period end NYMEX prices of $3.63 per Mcf, adjusted to $2.23 per Mcf at the wellhead, for natural gas and $49.66 per barrel, adjusted to $45.32 per barrel at the wellhead, for crude oil. This compares to a $59.0 million after-tax non-cash ceiling test impairment charge taken during the fourth quarter 2008. The write-down in value of our natural gas and crude oil properties in 2008 resulted from low year-end prices for the commodities. The write-down of gas and oil properties was based on year end NYMEX prices of $5.71 per Mcf, adjusted to $4.44 per Mcf at the wellhead, for natural gas and $44.60 per barrel, adjusted to $32.74 per barrel at the wellhead, for crude oil;

- LOE decreased $2.8 million due to lower production and cost reduction efforts;

- Lower depletion expense of $9.1 million primarily due to reduced depletion rate caused by a lower asset base as a result of previous asset impairment charges and lower production;

- Decreased production taxes of approximately $6.6 million primarily due to lower oil and natural gas prices; and

- A $3.8 million income tax benefit related to an adjustment of a previously recorded tax position.

Partially offsetting these were:

- Decreased revenues of $35.7 million primarily due to a 25% and 27% decrease in the annual average hedged price of oil and gas received, respectively, and a 6% and 8% decrease in oil and gas production, respectively. The decrease in natural gas production is due to a lower level of capital spending than in prior years and a voluntary shut-in of production at properties with the highest operating costs. Shut-ins reduced production for the year ended December 31, 2009 by approximately 458 MMcfe.

2008 Compared to 2007

Loss from continuing operations was $49.7 million after-tax compared to income from continuing operations of $12.7 million after-tax in the prior year, primarily due to:

- A $59.0 million after-tax non-cash ceiling test impairment charge was taken during the fourth quarter 2008. The write-down in the net carrying value of our natural gas and crude oil properties resulted from low year-end prices for the commodities. The write-down of gas and oil properties was based on year end NYMEX prices of $5.71 per Mcf, adjusted to $4.44 per Mcf at the wellhead, for natural gas and $44.60 per barrel, adjusted to $32.74 per barrel at the wellhead, for crude oil;

- LOE increased $3.6 million due to costs related to severe weather conditions in New Mexico, increased fuel costs and higher industry-related costs; and

- Increased depletion expense of $3.7 million primarily due to negative reserve revisions driven by the impact of lower year-end commodity prices.

Partially offsetting these was:

- Increased revenues of $4.8 million primarily due to a 32% increase in the annual average hedged price of oil received and a 1% increase in the annual average hedged price of gas received, partially offset by a 7% decrease in production and the impact of a royalty settlement with the Jicarilla Apache Nation. The decrease in production resulted from severe weather at the beginning of 2008, federal drilling permit delays, voluntary shut-in of volumes in response to low price levels at the CIG pricing location and delays in drilling activity on our non-operated property as well as a reduction in capital spending due to the low commodity prices.

Additional information on our Oil and Gas operations can be found in Note 21 to the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Power Generation

Our Power Generation segment produced the following results (in thousands):

	2009	2008	2007
Revenue	$30,575	$38,181	$38,658
Gain on sale of operating asset	25,971	-	-
Operating expenses	16,491	23,966	36,062
Operating income	40,055	14,215	2,596
Interest expense, net	9,388	11,649	5,918
Other (income) expense	(1,091)	(3,698)	2,397
Income tax expense (benefit)	11,097	3,013	(2,625)
Income (loss) from continuing operations	$20,661	$3,251	$(3,094)

The following table provides certain operating statistics for the Power Generation segment at December 31,:

	2009		2008		2007	
Independent power capacity:						
MW of independent power capacity in service	120		141		158	
Contracted fleet plant availability:						
Gas-fired plants	92.0	%	96.2	%	96.2	%
Coal-fired plants	96.1	%	95.3	%	70.3	%
Total	94.4	%	95.9	%	86.0	%

2009 Compared to 2008

Income from continuing operations was $20.7 million after-tax in 2009 compared to $3.3 million after-tax in 2008. The increase of $17.4 million was primarily due to:

- A $26.0 million gain on the sale of a 23.5% ownership interest in the Wygen I power generation facility;
- 2008 operating expenses reflect $3.1 million of allocated indirect costs relating to the IPP assets sold not reclassified to discontinued operations in accordance with accounting guidance for discontinued operations; and
- Interest expense in 2008 includes $8.7 million of allocated net interest expense relating to the IPP assets sold not reclassified to discontinued operations in accordance with accounting guidance for discontinued operations partially offset in 2009 by an increase in interest expense of $6.4 million primarily due to a change in intersegment debt to equity capital structure.

Partially offsetting these were:

- A decrease of $1.9 million reflecting net earnings impact of replacing a 20 MW PPA with operating and site lease agreements related to MEAN's purchase of a 23.5% ownership interest in Wygen I; and
- A $2.7 million gain on the sale of excess emission credits in 2008, which were made available by the decommissioning of the Ontario facility.

2008 Compared to 2007

Income from continuing operations was $3.3 million after-tax in 2008 compared to a loss from continuing operations of $3.1 million in 2007. The increase of $6.3 million was primarily due to:

- Increased earnings from our investments due to 2007 partnership impairment charges of $0.6 million for the Glenns Ferry and Rupert power plants, in which we hold a 50% ownership interest;
- Increased operating income from our Gillette CT of $1.0 million after-tax. Operating income was impacted by lower gas and purchased power costs and maintenance expense;
- Allocated indirect corporate costs, related to the IPP assets sold and not reclassified to discontinued operations decreased $1.9 million after-tax. 2008 costs represent a partial year through the sale date of the IPP Transaction, compared to a full 12 months of costs in 2007; and

- The recording of an impairment loss, and related costs, in 2007 of $2.7 million relating to the Ontario plant.

Partially offsetting the increased earnings was a decrease in non-operating income of $6.4 million after-tax, resulting from a change in business segment debt to equity capital structure.

Coal Mining

Coal Mining results were as follows (in thousands):

	2009	2008	2007
Revenue	$58,490	$56,901	$42,488
Operating expenses	53,435	52,608	36,311
Operating income	5,055	4,293	6,177
Interest income, net	(1,452)	(1,346)	(1,684)
Other income	(3,475)	(584)	(337)
Income tax expense	3,234	2,190	2,091
Income from continuing operations	$6,748	$4,033	$6,107

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

	2009	2008	2007
Tons of coal sold	5,955	6,017	5,049
Cubic yards of overburden moved	14,539	12,203	7,467
Coal reserves	268,000	274,000	280,000

2009 Compared to 2008

Income from continuing operations was $6.7 million after-tax in 2009 compared to $4.0 million after-tax in 2008. The increase of $2.7 million was due to:

- A $1.6 million increase in revenues primarily due to a higher average price received, partially offset by lower coal volumes sold. The higher average price received includes the impact of sales prices to our regulated utility subsidiaries that are determined in part by a return on investment base; and

- A $2.9 million increase in other income primarily from a site lease agreement recently entered into with the owners of Wygen III, which is located on mine property. The agreement provided for a March 2008 start date reflecting the commencement of construction on Wygen III.

Partially offsetting these was:

- A $0.8 million increase in operating costs primarily due to higher depreciation from an increased asset base and higher usage levels related to increased production, partially offset by lower estimated future reclamation costs.

2008 Compared to 2007

Income from continuing operations was $4.0 million after-tax in 2008 compared to $6.1 million after-tax in 2007. The decrease of $2.1 million was due to:

- Increased overburden removal costs of $5.3 million due to a 63% increase in overburden yards moved, compounded by a higher strip ratio, longer haul distances and higher diesel fuel costs; and

- Increased depreciation expense of $4.4 million due to an increase in the asset base and usage related to increased production.

Offsetting the decreases was a $14.4 million increase in revenues due to a 19% increase in coal sold at a higher average price. The increase in coal volumes was due to additional Wygen II and train load-out sales.

Energy Marketing

Our Energy Marketing segment produced the following results (in thousands):

	2009	2008	2007
Revenue:			
Realized gas marketing gross margin	$30,134	$18,593	$84,823
Unrealized gas marketing gross margin	(19,777)	33,247	468
Realized oil marketing gross margin	11,278	1,038	4,146
Unrealized oil marketing gross margin	(8,254)	6,432	4,399
	13,381	59,310	93,836
Operating expenses	13,804	29,175	42,067
Operating (loss) income	(423)	30,135	51,769
Interest expense (income), net	1,547	254	(2,131)
Other (income) expense	(22)	12	(24)
Income tax (benefit) expense	(460)	10,180	19,746
Income (loss) from continuing operations	$(1,488)	$19,689	$34,178

The following table provides certain operating statistics for the Energy Marketing segment:

	2009	2008	2007
Natural gas average daily physical sales - MMBtu	1,974,300	1,873,400	1,743,500
Crude oil average daily physical sales - Bbls	12,400	7,880	8,600

2009 Compared to 2008

Loss from continuing operations was $1.5 million after-tax in 2009 compared to income from continuing operations of $19.7 million in 2008. The decrease of $21.2 million was due to:

- A $67.7 million decrease in unrealized marketing margins, primarily due to prevailing conditions in natural gas markets affecting both transportation and storage strategies. Unrealized mark-to-market gains in 2008 were driven by accelerated margins within our proprietary trading portfolio and narrowing basis differentials at year end that resulted in unrealized mark-to-market gains on our hedged transportation positions. Those positions were settled and the margins realized primarily in 2009 and to a lesser extent in 2010.

Partially offsetting this was:

- A $21.8 million increase in realized marketing margins primarily due to settlement of trades which produced unrealized gains in the previous year; and

- Lower operating expenses of $15.4 million primarily due to a lower provision for incentive compensation.

2008 Compared to 2007

Income from continuing operations decreased $14.5 million due to:

- A $69.3 million decrease in realized marketing margins, primarily due to prevailing conditions in natural gas markets affecting both transportation and storage strategies; and

- Lower crude oil marketing margins due to the impact of decreasing commodity prices on inventory held to meet pipeline requirements.

Partially offsetting these were:

- A $34.8 million increase in unrealized marketing margins. Unrealized mark-to-market gains in 2008 were driven by accelerated margins within our proprietary trading portfolio and narrowing basis differentials at year end that resulted in unrealized mark-to-market gains on our hedged transportation positions. These positions were settled and the margins realized primarily in 2009 and to a lesser extent in 2010; and

- Lower operating expenses as incentive compensation decreased compared to incentive compensation for strong marketing performance in 2007.

Corporate

2009 Compared to 2008

Income from continuing operations was $21.1 million after-tax compared to a loss from continuing operations of $72.6 million after-tax in 2008. The increase of $93.7 million was primarily due to:

- A $97.6 million after-tax increase in unrealized mark-to-market gains related to certain interest rate swaps that are no longer designated as hedges for accounting purposes; and
- 2008 included $10.6 million in integration and acquisition costs.

Partially offsetting these was:

- A $14.2 million increase in net interest expense primarily due to interest settlements of the de-designated interest rate swaps and amortization of amendment fees to extend the mandatory early termination dates of these swaps through the end of 2010.

2008 Compared to 2007

Loss from continuing operations was $72.6 million after-tax in 2008 compared to a loss from continuing operations of $5.9 million after-tax in 2007. The decrease of $66.7 million was primarily due to:

- A $61.4 million after-tax unrealized mark-to-market loss related to interest rate swaps that were no longer designated as hedges for accounting purposes;
- A $2.4 million increase in net interest expense due to higher borrowings; and
- A $10.6 million increase in costs from integration and acquisition of the utilities purchased in the Aquila Transaction.

Critical Accounting Estimates

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

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

Impairment of Long-lived Assets

We evaluate for impairment, the carrying values of our long-lived assets, including goodwill and other intangibles, whenever indicators of impairment exist and at least annually for goodwill as required by accounting standards for goodwill.

For long-lived assets with finite lives, this evaluation is based upon our projections of anticipated future cash flows (undiscounted and without interest charges) from the assets being evaluated. If the sum of the anticipated future cash flows over the expected useful life of the assets is less than the assets' carrying value, then a permanent non-cash write-down equal to the difference between the assets' carrying value and the assets' fair value is required to be charged to earnings. In estimating future cash flows, we generally use a probability weighted average expected cash flow method with assumptions based on those used for internal budgets. The determination of future cash flows, and, if required, fair value of a long-lived asset is by its nature a highly subjective judgment. Significant assumptions are required in the forecast of future operating results used in the preparation of the long-term estimated cash flows. Changes in these estimates could have a material effect on the evaluation of our long-lived assets.

According to accounting standards for goodwill, goodwill and other intangibles are required to be evaluated whenever indicators of impairment exist and at least annually. We conduct our annual evaluations during the fourth quarter. The standard requires a two-step process be performed to analyze whether or not goodwill has been impaired. The first step of this test, used to identify potential impairment, compares the estimated fair value of a reporting unit with its carrying amount. The second step, if necessary, measures the amount of the impairment. The underlying assumptions used for determining fair value are susceptible to change from period to period and could potentially cause a material impact to the income statement. Management's assumptions about future revenues and operating costs, the amount and timing of anticipated capital expenditures for power generating facilities, discount rates, inflation rates, and economic conditions, require significant judgment.

We have $353.7 million in goodwill as of December 31, 2009, of which $339.0 million relates to our Black Hills Energy utilities. Colorado Electric holds 72% and the Gas Utilities hold 28% of the Black Hills Energy goodwill. For the Colorado Electric impairment analysis, we estimate the fair value of the goodwill using a discounted cash flows methodology. This analysis required the input of several critical assumptions in building our risk-adjusted discount rate and cash flow projections including future growth rates, operating cost escalation rates, timing and level of success in regulatory rate proceedings, and the cost of debt and equity capital. We believe the goodwill amount reflects the value of the opportunity to build a significant amount of rate-based generation and transmission in the next two years followed by the relatively stable, long-lived cash flows of the regulated utility business, considering the regulatory environment and market growth potential. The results of the analysis show Colorado Electric with a carrying value of $489.2 million as of November 30, 2009, compared to a fair value of $591.9 million. The fair value exceeds the carrying value by 21%; therefore we do not have an impairment.

The remaining $93.9 million of goodwill relates to the Gas Utilities. We tested this goodwill for impairment using an EBITDA multiple method and a discounted cash flow method at each reporting unit. The analysis required the input of several critical assumptions in determining EBITDA, the multiple to apply to EBITDA, cash flow projections and risk-adjusted discount rate. These assumptions include future growth rates, operating cost escalation rates, timing and level of success in regulatory rate proceedings, and long-term earnings and merger multiples for comparable companies. The results of the analysis show the Gas Utilities with a carrying value of $466.3 million as of November 30, 2009, compared to a fair value of $777.4 million. The fair value exceeds the carrying value by 67%; therefore we do not have an impairment.

Full Cost Method of Accounting for Oil and Gas Activities

Accounting for oil and gas activities is subject to special, unique rules. Two generally accepted methods of accounting for oil and gas activities are available - successful efforts and full cost. We account for our oil and gas activities under the full cost method whereby all productive and nonproductive costs related to acquisition, exploration and development drilling activities are capitalized. These costs are amortized using a unit-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are treated as adjustments to the cost of the properties with no gain or loss recognized. Net capitalized costs are subject to a ceiling test that limits such costs to the aggregate of the present value of future net revenues of proved reserves and the lower of cost or fair value of unproved properties. This method values the reserves based upon SEC-defined prices for oil and gas as of the end of each reporting period adjusted for contracted price changes. The prices, as well as costs and development capital, are assumed to remain constant for the remaining life of the properties. If the net capitalized costs exceed the full-cost ceiling, then a permanent non-cash write-down is required to be charged to earnings in that reporting period. Under these SEC-defined product prices, our net capitalized costs were more than the full cost ceiling at March 31, 2009 and December 31, 2008 requiring an after-tax write-down of $27.8 million and $59.0 million, respectively. Under the SEC-defined product prices at December 31, 2009, no additional write-down was required. Given the fluctuations in natural gas and oil prices, we can provide no assurance that future write-downs will not occur depending on oil and gas prices at that point in time. On December 31, 2008, the SEC issued final rules amending its oil and gas reporting requirements effective for fiscal years ending on or after December 31, 2009 and apply to the Annual Reports on Form 10-K. The final rule changes the use of prices at the end of each reporting period to an average of the first day of the month price for the preceding twelve months.

Oil and Natural Gas Reserve Estimates

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

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

Risk Management Activities

In addition to the information provided below, see Note 3, "Risk Management Activities" and Note 4, "Fair Value Measurement," of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Derivatives

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

We currently use derivative instruments, including options, swaps, futures, forwards and other contractual commitments for both non-trading (hedging) and trading purposes. Our typical non-trading (hedging) transactions relate to contracts we enter into to fix the price received for anticipated future production at our Oil and Gas segment, or to fulfill the annual winter hedging plan for our regulated gas utilities (see below), and for interest rate swaps we enter into to convert a portion of our variable rate debt, or associated variable rate interest payments, to a fixed rate. Our Energy Marketing operations utilize various physical and financial contracts to effectively manage our marketing and trading portfolios.

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

Pricing models and their underlying assumptions impact the amount and timing of unrealized gains and losses recorded, and the use of different pricing models or assumptions could produce different financial results. Changes in the commodity markets will impact our estimates of fair value in the future. To the extent financial contracts have extended maturity dates, our estimates of fair value may involve greater subjectivity due to the lack of transparent market data available upon which to base modeling assumptions. A 20% change to the estimated fair value prices would have affected 2009 net income by approximately $3.6 million.

As allowed by state regulatory commissions, we have entered into certain financial instruments to reduce our customers' underlying exposure to fluctuations in gas prices. These financial instruments are considered derivatives and are marked-to-market. We apply the accounting standards for regulated operations to periodic changes in fair value of the derivatives associated with these instruments and record an offset in regulatory asset or regulatory liability accounts. Most of our contracts for purchase and sale of natural gas qualify for the normal purchase and normal sale exceptions under accounting standards for derivatives, and are not required to be recorded as derivative assets and liabilities.

Counterparty Credit Risk and Allowance for Doubtful Accounts

Our largest counterparties consist primarily of financial institutions and major energy companies. This concentration of counterparties may materially impact our exposure to credit risk resulting from market, economic or regulatory conditions. Recent adverse developments in the global financial and credit markets have made it more difficult and more expensive for companies to access the short-term bank markets, which may negatively impact the creditworthiness of our counterparties. We seek to minimize counterparty credit risk through an evaluation of their financial condition and credit ratings and collateral requirements under certain circumstances, including the use of master netting agreements in our energy marketing segment.

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

Pension and Other Postretirement Benefits

The Company, as described in Note 18 to the Consolidated Financial Statements in this Annual Report on Form 10-K, has three defined benefit pension plans and three defined post-retirement healthcare plans. Accounting for pension and other postretirement benefit obligations involves numerous assumptions, the most significant of which relate to the discount rate for measuring the present value of future plan obligations; expected long-term rates of return on plan assets; rate of future increases in compensation levels; and healthcare cost projections. The determination of our obligation and expenses for pension and other postretirement benefits is dependent on the assumptions used by actuaries in calculating the amounts. In 2008, we changed our measurement date to December 31. Although we believe our assumptions are appropriate, significant differences in our actual experience or significant changes in our assumptions may materially affect our pension and other postretirement obligations and our future expense.

In July 2009, the Board of Directors froze our Defined Benefit Pension Plans to certain new participants and transferred certain existing participants to an age and service based defined contribution plan, effective January 1, 2010. Plan assets and obligations for the Black Hills Corporation Plan which covers eligible employees of Black Hills Service Company, Black Hills Power, WRDC, and BHEP, and the Black Hills Utility Holdings Plan, which covers eligible employees of our Black Hills Utility Holding subsidiaries were revalued as of July 31, 2009 in conjunction with the curtailment of these plans. As a result, we recognized a pre-tax curtailment expense of approximately $0.3 million in the third quarter of 2009. The Cheyenne Light Plan recognized a pre-tax curtailment expense of less than $0.1 million and this expense was booked in the fourth quarter of 2009. In July 2009, the Board of Directors also approved amendments to the BHC Retiree Healthcare Plan and the Black Hills Utility Holdings Plan effective January 1, 2010, from a cost sharing plan to a RMSA for non-union employees and participating union employees and expand eligibility of plan participants.

The pension benefit cost for 2010 for our non-contributory funded pension plan is expected to be $9.9 million compared to $11.8 million in 2009. The estimated discount rate used to determine annual benefit cost accruals will be 6.0% in 2010; the discount rate used in 2009 was 6.2%. In selecting the discount rate, we consider cash flow durations for each Plan's liabilities and returns on high credit quality fixed income yield curves for comparable durations.

Our pension plan assets are held in trust and primarily consist of equity, fixed income and real estate securities. In 2009, our target long-term investment allocations were 65% equity and 35% fixed income. At December 31, 2009, our investment allocation was 65% equities, 32% fixed income/cash and 3% real estate.

We do not pre-fund our non-qualified pension plans or two of the three postretirement benefit plans. The table below shows the expected impacts of a 1% increase or decrease to our 5.68% discount rate assumption for our Retiree Healthcare Plans (in thousands):

Change in Assumed Discount Rate	Impact on December 31, 2009 Accumulated Postretirement Benefit Obligation	Impact on 2009 Service and Interest Cost
Increase 1%	$ 3,057	$ 384
Decrease 1%	$ (2,505)	$ (275)

Contingencies

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

Valuation of Deferred Tax Assets

We use the liability method of accounting for income taxes. Under this method, deferred income taxes are recognized, at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities, as well as operating loss and tax credit carryforwards. The amount of deferred tax assets recognized is limited to the amount of the benefit that is more likely than not to be realized.

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. If we determine that we will be unable to realize all or part of our deferred tax assets in the future, an adjustment to the deferred tax asset would be charged to income in the period such determination was made. Although we believe our assumptions, judgments and estimates are reasonable, changes in tax laws or our interpretations of tax laws and the resolution of the current and any future tax audits could significantly impact the amounts provided for income taxes in our consolidated financial statements.

Liquidity and Capital Resources

Overview

Information about our financial position as of December 31 is presented in the following table (dollars, in thousands):

Financial Position Summary	2009	2008	Percentage Change
Cash and cash equivalents	$112,901	$168,491	(33.0)%
Restricted cash	17,502	-	100.0 %
Short-term debt	199,745	705,878	(71.7)%
Long-term debt	1,015,912	501,252	102.7 %
Stockholders' equity	1,084,837	1,050,536	3.3 %
Ratios			
Long-term debt ratio	48.4 %	32.3 %	49.7 %
Total debt ratio	52.8 %	53.5 %	(1.2)%

We believe that our cash on hand, operating cash flows, existing borrowing capacity and ability to complete new debt financings, taken as a whole, provide sufficient resources to fund our ongoing operating requirements, debt maturities, anticipated dividends, and anticipated capital expenditures during the next twelve months. However, a material change in available financing (including further changes resulting from a recurrence of the capital market disruptions experienced in 2008 and early 2009) could impact our ability to fund our current liquidity and capital resource requirements.

Liquidity

Historically, our principal sources of short-term liquidity have been our revolving credit facilities and cash from operations. We have utilized availability under our revolving credit facilities to manage our cash flow needs, which are affected by the seasonality of our utility businesses and changes in the trading volumes of our energy marketing operation. Our principal sources of long-term liquidity have been proceeds raised from public and private offerings of equity and long-term debt securities issued by the Company and its subsidiaries. We have also managed liquidity needs through hedging activities, primarily in connection with seasonal needs of our Utility operations (including seasonal peaks in fuel requirements), interest rate movements, and commodity price movements.

At December 31, 2009, we had approximately $112.9 million of unrestricted cash on hand and approximately $315.7 million of additional capacity on our Corporate Credit Facility available for additional borrowings or letters of credits. We had the following cash borrowings and letters of credit outstanding under our credit facilities, as set forth below (in millions):

Credit Facility	Expiration	Maximum Capacity	Borrowings and Letters of Credit Issued at December 31, 2009
Corporate Credit Facility	May 4, 2010	$ 525.0	$ 209.3

Enserco Facility	May 7, 2010	$ 300.0	$ 103.0

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Credit Facilities and Long-Term Debt

Corporate Credit Facility

Our unsecured revolving credit facility has a maximum capacity of $525 million. The cost of borrowing or letters of credit under our corporate revolver is determined based on our credit ratings. At our current ratings levels, the facility has an annual facility fee of 17.5 basis points, and has a borrowing spread of 70 basis points over LIBOR (which equates to a 0.93% one-month borrowing rate as of December 31, 2009). The revolver can be used to fund our working capital needs and for general corporate purposes. At December 31, 2009, we had borrowings of $164.5 million and $44.8 million of letters of credit issued under the facility, and we had approximately $315.7 million of capacity available for additional borrowings or letters of credit.

Our revolving credit facility contains customary affirmative and negative covenants, such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions, and maintenance of the following financial covenants: (i) a consolidated net worth in an amount of not less than the sum of $625 million and 50% of our aggregate consolidated net income beginning January 1, 2005; (ii) a recourse leverage ratio not to exceed 0.65 to 1.00 and, (iii) an interest expense coverage ratio of not less than 2.5 to 1.0. Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding.

At December 31, 2009, our consolidated net worth was $1,084.8 million, which was approximately $259.9 million in excess of the net worth we were required to maintain under the credit facility. At December 31, 2009, our long-term debt ratio was 48.4%, our total debt leverage (long-term debt and short-term debt) was 52.8%, our recourse leverage ratio was approximately 55.2% and our interest expense coverage ratio for the year ended December 31, 2009 was 4.10 to 1.0. Accordingly, we were in compliance with all of our financial covenants in the revolving credit facility as of December 31, 2009.

In addition to covenant violations, an event of default under the credit facility may be triggered by other events, such as a failure to make payments when due or a failure to make payments when due in respect of, or a failure to perform obligations relating to, other debt obligations of $20 million or more. Subject to applicable cure periods (none of which apply to a failure to timely pay indebtedness), an event of default would permit the lenders to restrict our ability to further access the credit facility for loans or new letters of credit, and could require both the immediate repayment of any principal and interest outstanding and the cash collateralization of outstanding letter of credit obligations.

The credit facility prohibits us from paying cash dividends if a default or an event of default exists prior to, or would result after giving effect to such action.

Enserco Credit Facility

On May 8, 2009, Enserco entered into an agreement for a $240 million committed credit facility. Societe Generale, Fortis Capital Corp., and BNP Paribas were co-lead arranger banks. On May 27, 2009, Enserco entered into an agreement for an additional $60 million of commitments under the credit facility with three participating banks: Credit Agricole Corporate and Investment Bank, Rabobank and RZB Finance. The $300 million credit facility expires on May 7, 2010. The facility is a borrowing base line of credit, the structure of which requires certain levels of net worth and net working capital to be maintained for a given borrowing base election level. In order to maintain a borrowing base election level, we may be restricted from making dividend payments from Enserco to the Parent. Maximum borrowings under the facility are subject to a sublimit of $50 million. Borrowings under this facility are available under a base rate option or a Eurodollar option. The base rate option borrowing rate is 2.75% plus the higher of: (i) 0.5% above the Federal Funds Rate, or (ii) the prime rate established by Fortis Bank S.A./N.V. The Eurodollar option borrowing rate is 2.75% plus the higher of the Eurodollar Rate or the reference bank cost of funds. The facility structure requires certain levels of tangible net worth and net working capital to be maintained for a given borrowing base election level. In order to maintain a borrowing base election level, we may be restricted from making dividend payments from Enserco to the parent company. At December 31, 2009, $103 million of letters of credit were issued under this facility and there were no cash borrowings outstanding.

We expect to replace the Corporate Credit Facility and the Enserco Credit Facility with similar facilities prior to their maturities. We expect to renew the Corporate Credit Facility for a three-year term at a $400 to $500 million total commitment level and the Enserco Credit Facility for a one-year term at a $250 million level.

Acquisition Facility

In July 2008, in conjunction with the closing of the Aquila Transaction, we borrowed $382.8 million under our $1 billion bridge acquisition credit facility dated May 7, 2007. The Acquisition Facility was structured as a single-draw term loan facility for the sole purpose of financing the Aquila Transaction. During 2009, we paid off the Acquisition Facility with proceeds of $30.2 million from the sale of 25% of the Wygen III plant to MDU, net proceeds from the $250 million public debt offering of senior notes, and with borrowings of $104.6 million on our Corporate Credit Facility.

Industrial Development Revenue Bonds

Cheyenne Light completed a $17 million weekly variable rate refunding bond issuance on September 3, 2009. The new issue replaced existing debt and converted the bond credit support structure from an AMBAC Financial Group insurance policy to a direct-pay letter of credit issued by Wells Fargo Bank. Laramie County, Wyoming was the tax-exempt conduit issuer for this transaction. The bonds were issued in two series: a $10.0 million series maturing March 1, 2027, and a $7.0 million series maturing September 1, 2021. The principal amounts and maturity dates did not change from the original financing. Including the letter of credit fees and other issuance costs, the current all-in rate as of December 31, 2009, was approximately 2.69%.

Under the terms of our Reimbursement Agreement with the letter of credit provider, Cheyenne Light is required to maintain a consolidated debt to capitalization ratio of no more than 0.60 to 1.00 and a consolidated interest coverage ratio greater than or equal to 2.50 to 1.00. If Cheyenne Light fails to meet these covenants, subject to a 30-day cure period, it would constitute an event of default and the bank would have the right to cause the bonds and related outstanding obligations to become immediately due and payable.

Cross-Default Provisions

Our revolving credit facility contains cross-default provisions that would result in an event of default under the credit facility upon (i) a failure by us or certain of our subsidiaries (including, among others, Enserco and most of our Utility subsidiaries) to timely pay indebtedness in an aggregate principal amount of $20 million or more, or (ii) the occurrence of a default under any agreement under which we or certain of our subsidiaries (including, among others, Enserco and most of our Utility subsidiaries) may incur indebtedness in an aggregate principal amount of $20 million or more, and such default continues for a period of time sufficient to permit an acceleration of the maturity of such indebtedness or a mandatory prepayment of such indebtedness. In addition, our credit facility contains default provisions under which an event of default would result if we or certain of our subsidiaries (including, among others, Enserco and most of our Utility subsidiaries) fail to timely make certain payments, such as ERISA funding obligations or payments in satisfaction of judgments, in an aggregate principal amount of $20 million or more.

Holding Company Debt Offering

In May 2009, we issued a $250 million aggregate principal amount of senior unsecured notes due in 2014 pursuant to a public offering. The notes were priced at par and carry a fixed interest rate of 9%. We received proceeds of $248.5 million, net of underwriting fees. Proceeds were used to pay down a portion of the Acquisition Facility. Deferred financing costs related to the offering of $2.3 million were capitalized and are being amortized over the term of the debt.

Black Hills Power Bond Issuance

In October 2009, our regulated utility Black Hills Power completed a $180.0 million first mortgage bond issuance. The bonds were priced at 99.931% of par with a reoffer yield of 6.13%. The bonds mature on November 1, 2039, and carry an annual interest rate of 6.125%, which will be paid semi-annually. We received proceeds of $178.3 million net of underwriting fees, which were used to repay borrowings under the Corporate Credit Facility. Deferred financing costs of $2.2 million were capitalized and are being amortized over the term of the bonds.

Black Hills Wyoming Project Financing

On December 9, 2009, our subsidiary Black Hills Wyoming issued $120.0 million in project financing debt. The debt is secured by our ownership interest in the Wygen I facility and by the Gillette CT generation facility. The loan amortizes over a seven-year term and matures on December 9, 2016, at which time the remaining balance of $83.0 million is due. Principal and interest payments are made on a quarterly basis with the principal payments based on projected cash flows available for debt service. Interest is charged at LIBOR plus 3.25% (3.49% at December 31, 2009). Proceeds were used to repay borrowings on the Corporate Credit Facility. Estimated deferred financing costs of $6.2 million were capitalized and are being amortized over the term of the debt. Black Hills Non-regulated Holdings, the Parent of Black Hills Wyoming, must maintain equity of $100.0 million. We were in compliance of this requirement at December 31, 2009.

Our Black Hills Wyoming project financing is secured by our ownership interest in the Wygen I plant and by the Gillette CT plant. The financing places restrictions on dividends or the loaning of funds by Black Hills Wyoming, and allows it only in limited circumstances when cash flows for the projects exceed project debt service and reserve requirements. We had approximately $39.1 million of equity at Black Hills Wyoming as of December 31, 2009.

Interest Rate Swaps

We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations. We have interest rate swaps with a notional amount of $250.0 million that are not designated as hedge instruments. Accordingly, mark-to-market changes in value on the swaps are recorded within the income statement. For the year ended December 31, 2009, we recorded a $55.7 million pre-tax unrealized mark-to-market non-cash gain on the swaps. For the year ended December 31, 2008, we recorded a $94.4 million pre-tax unrealized mark-to-market non-cash loss on the swaps. The mark-to-market value on these swaps was a liability of $38.8 million at December 31, 2009. Subsequent mark-to-market adjustments could have a significant impact on our results of operations. A one basis point move in the interest rate curves over the term of the swaps would have a pre-tax impact of approximately $0.3 million. 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 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 stated termination dates.

In addition, we have $150.0 million notional amount floating-to-fixed interest rate swaps, having a maximum term of seven years. These swaps have been designated as cash flow hedges and accordingly, their mark-to-market adjustments are recorded in Accumulated other comprehensive loss on the accompanying Consolidated Balance Sheets. The mark-to-market value of these swaps was a liability of $15.4 million at December 31, 2009.

Working Capital

The most significant items impacting working capital are our capital expenditures, the purchase of natural gas for our regulated Gas Utilities, and funding for natural gas and crude oil marketing activities. We could experience significant working capital requirements during peak months of the winter heating season due to higher natural gas consumption and during periods of high natural gas prices. We anticipate using a combination of credit capacity available under our corporate revolver and cash on hand to meet our peak winter working capital requirements.

Our Energy Marketing segment engages in trading activities involving natural gas storage which carry working capital requirements. The level of those requirements vary depending on market circumstances, the capacity contracted for by the Company and the degree to which the Company has elected to utilize those opportunities. In addition, Enserco's credit facility contains working capital requirements for each borrowing base election level.

Collateral

As of December 31, 2009, we had posted with counterparties the following amounts of collateral in the form of cash or letters of credit (in thousands):

Trading positions (energy marketing)	$ 133,805
Utility cash collateral requirements	3,789
Letters of credit on Corporate Credit Facility	44,752
Total Funds on Deposit	$ 182,346

Collateral requirements for our trading positions will fluctuate based on the movement in commodity prices and our credit rating. Changes in collateral requirements will vary depending on the magnitude of the price movement and the current position of our energy marketing trading portfolio. As these trading positions settle in the future, the collateral will be returned.

At our Gas Utilities and Energy Marketing segments, we are required to post collateral with certain commodity and pipeline transportation vendors. This amount will fluctuate depending on gas prices and projected volumetric deliveries.

Utility Money Pool

As a utility holding company, we are required to establish a cash management program to address lending and borrowing activities between our utility subsidiaries and the Company. We have established utility money pool agreements which address these requirements. These agreements are on file with FERC and appropriate state regulators. Under the utility money pool agreements, our utilities may borrow and extend short-term loans to our other utilities via a utility money pool at market-based rates (0.93% at December 31, 2009). While the utility money pool may borrow funds from the Company (as ultimate parent company), the money pool arrangement does not allow loans from our utility subsidiaries to the Company (as ultimate parent company) or to non-regulated affiliates.

At December 31, 2009, money pool balances included (in thousands):

Subsidiary	Borrowings From (Loans To) Money Pool Outstanding at December 31, 2009	
Black Hills Utility Holdings	$	128,357
Black Hills Power	$	(59,309)
Cheyenne Light	$	(1,182)

Registration Statements

Our articles of incorporation authorize the issuance of 100 million shares of common stock, $1 par value, and 25 million shares of preferred stock, no-par value. As of December 31, 2009, we had approximately 39.0 million shares of common stock outstanding, and no shares of preferred stock outstanding. The Company has an effective automatic shelf registration statement on file with the SEC under which we may issue, from time to time, senior debt securities, subordinated debt securities, common stock, preferred stock, warrants and other securities. Although the shelf registration statement does not limit our issuance capacity, our ability to issue securities is limited to the authority granted by our Board of Directors, certain covenants in our finance arrangements and restrictions imposed by federal and state regulatory authorities.

Anticipated Financing Plans

We have substantial capital expenditure requirements in 2010 and 2011, which are primarily due to the construction of additional generation to serve our Colorado Electric utility. Our capital requirements for 2010 and 2011 are expected to be financed through a combination of operating cash flows, borrowings on our revolving credit facility and long-term financings. We intend to maintain a consolidated debt-to-capitalization level in the range of 50% to 55%.

We expect to complete long-term senior unsecured debt financings at the holding company level in 2010 or 2011; a portion of the long-term debt financings may be completed at certain subsidiaries. We also intend to complete a portion of the permanent financing through the issuance of common stock to maintain our target debt to capitalization level.

Factors Influencing Liquidity

Many of our operations are subject to seasonal fluctuations in cash flow. We have traditionally sourced (i) variations in the working capital needs of our subsidiaries with cash on hand and capacity available under our credit facilities, and (ii) the capital expenditures of our subsidiaries through a combination of internally generated cash, equity contributions and borrowings by our subsidiaries from us (financed primarily with net proceeds of equity and long-term debt issuances by us) and, in limited instances, debt offerings by our subsidiaries. Increased volatility in commodity prices and interest rates has made it more difficult for us to adequately forecast the liquidity needs of our subsidiary operations. Moreover, based on general market conditions and various predictions of a prolonged recession and weak recovery, we face an increasing risk of higher payment defaults by our customers. As a result, our liquidity needs are subject to greater fluctuation and are more difficult to forecast than in the past.

To the extent we issue long-term debt securities or arrange new credit facilities or extensions of existing credit lines in the bank loan market, we expect to pay significant fees in connection with these activities. In particular, future banking fees for new credit facilities or additional maturity extensions may be significantly more costly than in the past.

Although our Utility operations are subject to regulatory lag in terms of recovering capital expenditures and other prudently-incurred costs, revenues from our Utility operations traditionally have been stable. In light of volatile commodity prices and the lingering effects of a severe economic recession, our cash flows from Utility operations could be less stable going forward.

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

Due to market conditions, the funding status of our pension plans for 2010 and future periods is subject to multiple variables, most of which are beyond our control, including changes to the fair value of the pension assets and changes in actuarial assumptions (in particular, the discount rate used in determining the projected benefit obligation). As a result, we may be required to contribute material amounts to our pension plans in 2010 and future periods, which could materially affect our liquidity and results of operations.

Credit Ratings

Credit ratings impact our ability to obtain short- and long-term financing, the cost of such financing, and vendor payment terms, including collateral requirements. As of December 31, 2009, our senior unsecured credit ratings, as assessed by the three major credit rating agencies, were as follows:

Rating Agency	Rating	Outlook
Moody's	Baa3	Stable
S&P	BBB-	Stable
Fitch	BBB	Stable

In addition, the first mortgage bonds issued by Black Hills Power were rated at December 31, 2009 as follows:

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

We do not have any trigger events (i.e., an acceleration of repayment of outstanding indebtedness, an increase in interest costs or the posting of additional cash collateral) tied to our stock price and have not executed any transactions that require us to issue equity based on our credit ratings or other trigger events. If our senior unsecured credit rating should drop below investment grade, pricing under our credit agreements would be affected, increasing annual interest expense by approximately $1.2 million pre-tax based on our December 31, 2009 debt balances.

We have an interest rate swap with a notional amount of $50.0 million which has collateral requirements based upon our corporate credit ratings. At our current credit ratings, we would be required to post collateral for any amount by which the swap's negative mark-to-market fair value exceeds $20.0 million. If our senior unsecured credit rating would drop to BB+ or below by S&P, or Ba1 or below by Moody's, we would be required to post collateral for the entire amount of the swap's negative mark-to-market fair value.

Capital Requirements

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

	2009		2008		2007	
Acquisition costs:						
Payment for acquisition of net assets, net of cash acquired	$-		$938,423	(1)	$-	
Property additions:						
Utilities -						
Electric Utilities	241,963	(2)	186,237	(2)	104,963	(2)(3)
Gas Utilities	43,005		19,337	(4)	-	
Non-regulated Energy -						
Oil and Gas	20,522		89,169	(5)	72,153	
Power Generation	20,537	(6)	5,105		128	
Coal Mining	11,765		25,190		4,991	
Energy Marketing	220		22		177	
Corporate	9,807		11,033		22,316	(7)
	347,819		336,093		204,728	
Discontinued operations investing activities	-		29,836	(8)	62,319	(8)
	347,819		1,304,352		267,047	
Common stock dividends	55,151		53,663		50,300	
Maturities/redemptions of long-term debt	2,173		130,297		62,109	
Discontinued operations financing activities	-		73,928		12,858	
	$405,143		$1,562,240		$392,314	

(1) Cash paid for the Aquila properties, net of cash acquired.
(2) Includes $61.9 million, $99.3 million and $13.5 million for Wygen III construction in 2009, 2008 and 2007, respectively, reflecting our 75% ownership interest in the plant, $48.1 million in 2009 for construction associated with our Colorado Electric Energy Resource Plan, and $21.1 million and $24.0 million in new transmission projects in 2009 and 2008, respectively. 2008 includes Colorado Electric acquired July 14, 2008.
(3) Includes $50.4 million for construction of Wygen II.
(4) The Gas Utilities were acquired on July 14, 2008.
(5) Includes $16.9 million for acquisition of a non-operated interest in Wyoming in 2008.
(6) Includes $16.4 million in 2009 for construction of two 100 MW natural gas-fired power generation facilities at Colorado IPP.
(7) Includes $19.1 million for Aquila acquisition and development costs.
(8) Includes $27.8 million and $62.2 million in 2008 and 2007, respectively, for the construction of the Valencia plant, which was sold in the IPP Transaction.

Our capital additions for 2009 were $347.8 million. Capital expenditures were primarily for construction of the Wygen III power plant, construction of natural gas-fired power generation facilities at or benefiting Colorado Electric.

Our capital additions for 2008 were $365.9 million, exclusive of the $938.4 million payment for the Aquila Transaction. Capital expenditures were primarily for construction of the Wygen III power plant, acquisition of non-operated oil and gas interests in Wyoming, development drilling of oil and gas properties, increased coal mining equipment and maintenance capital.

Our capital additions for 2007 were $267.0 million. Capital expenditures were primarily for the construction of the Wygen II power plant, the Valencia power plant, which is reclassified to Discontinued operations, development drilling of oil and gas properties, capitalized costs associated with the Aquila Transaction, and maintenance capital.

Forecasted Capital Expenditures

Forecasted capital requirements for maintenance capital and development capital are as follows (in thousands):

	2010	2011	2012
Regulated Utilities:			
Electric Utilities(1)(2)	$277,360	$228,910	$120,530
Gas Utilities	56,480	56,070	56,730
Non-regulated Energy:			
Oil and Gas(3)	38,320	63,810	79,770
Power Generation(4)	86,300	150,420	2,390
Coal Mining	16,540	17,260	12,610
Energy Marketing	400	400	400
Corporate	-	-	-
	$475,400	$516,870	$272,430

(1) Electric Utilities capital requirements include approximately $12.0 million for the development of the Wygen III coal-fired plant in 2010 reflecting our 75% ownership interest in the plant.

(2) Capital expenditures for our Electric Utilities include expenditures associated with our Colorado Electric Energy Resource Plan. The construction of two natural gas-fired combustion turbine facilities at Colorado Electric are expected to cost approximately $240 million to $260 million. The planned expenditures included in this table reflect the mid-point of this range. We expect to spend approximately $130.2 million and $72.8 million in 2010 and 2011, respectively, for this construction. Included in these expected expenditures is $25.3 million and $13.6 million in 2010 and 2011, respectively, for transmission construction projects at Colorado Electric.

(3) Development capital for our oil and gas properties is expected to be limited to no more than the cash flows produced by those properties. Continued low commodity prices make many of our development drilling sites uneconomical, which could further reduce our development capital expenditures.

(4) Our Power Generation segment was awarded the bid to provide 200 MW of power through a 20-year PPA with Colorado Electric. The total construction cost is expected to be approximately $240 million to $265 million which is expected to be completed by the end of 2011. The planned expenditures included in this table reflect the mid-point of this range. We expect to spend approximately $80.0 million and $149.9 million in 2010 and 2011, respectively, on this construction.

Contractual Obligations and Commitments

The following information is provided to summarize our cash obligations and commercial commitments at December 31, 2009. Actual future costs of estimated obligations may differ materially from these amounts.

	Payments Due by Period (in thousands)				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Long-term debt(a)(b)	$1,051,380	$35,245	$242,492	$273,347	$500,296
Unconditional purchase obligations(c)	1,239,203	338,705	436,821	163,364	300,313
Operating lease obligations(d)	15,200	2,612	4,819	2,454	5,315
Capital leases(e)	29	22	7	-	-
Other long-term obligations(f)	39,663	-	-	-	39,663
Employee benefit plans(g)	156,826	5,166	42,887	36,441	72,332
Liability for unrecognized tax benefits in accordance with accounting guidance for uncertain tax positions(h)	47,952	-	32,737	14,928	287
Credit facilities	164,500	164,500	-	-	-
Total contractual cash obligations(i)	$2,714,753	$546,250	$759,763	$490,534	$918,206

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

(b) The following amounts are estimated for interest payments on long-term debt over the next five years: $69.5 million in 2010, $68.0 million in 2011, $67.7 million in 2012, $59.9 million in 2013 and $41.0 in 2014. Estimated interest payments on variable rate debt are calculated by utilizing the applicable rates as of December 31, 2009.

(c) Unconditional purchase obligations include the capacity costs associated with our power purchase agreement with PacifiCorp, the capacity and energy costs associated with our power purchase agreement with PSCo, and certain transmission, gas purchase and gas transportation and storage agreements. The energy charge under the purchase power agreement and the commodity price under the gas purchase contract are variable costs, which for purposes of estimating our future obligations, were based on costs incurred during 2009 and price assumptions using existing prices at December 31, 2009. The pricing for the PSCo power purchase agreement is based on annual contracted capacity and an 85% load factor at current FERC approved rates. Our transmission obligations are based on filed tariffs as of December 31, 2009.

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

(e) Represents a capital lease on office equipment.

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

(g) Represents estimated employer contributions to employee benefit plans through the year 2019.

(h) Years 1-3 includes an estimated reversal of approximately $21.2 million associated with the gain deferred from the tax treatment related to the IPP Transaction and the Aquila Transaction. The liability includes an income tax refund receivable of approximately $59.1 million that is long-term in nature and reflected in the After 5 Years category in the above table.

(i) Amounts in the above table exclude any obligation that may arise from our derivatives, including interest rate swaps and commodity related contracts that have a negative fair value at December 31, 2009. These amounts have been excluded as it is impracticable to reasonably estimate the final amount and/or timing of any associated payments.

Dividends

Our dividend payout ratio for the year ended December 31, 2009, was 67% compared to 51% and 52% for the years ended December 31, 2008 and 2007, respectively. Dividends paid on our common stock totaled $1.42 per share in 2009, as compared to $1.40 per share in 2008 and $1.37 per share in 2007. Our three-year annualized dividend growth rate was 2.5%, and all dividends were paid out of operating cash flows.

In January 2010, our Board of Directors declared a quarterly dividend of $0.36 per share. If this dividend is maintained throughout 2010, it will be equivalent to $1.44 per share. The determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other things, our financial condition, funds from operations, the level of our capital expenditures, restrictions under our credit facilities and our future business prospects.

Dividend Restrictions

Due to our holding company structure, substantially all of our operating cash flow is provided by dividends paid or distributions made by our subsidiaries. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. Our utility subsidiaries are generally limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As of December 31, 2009, the net assets restricted from distribution at our regulated Electric and regulated Gas Utilities were approximately $277.0 million.

In December 2009, one of the covenants to the Enserco Credit Facility was amended to temporarily increase the allowable rolling twelve month Net Cumulative Loss as calculated on a Non-GAAP basis and temporarily restrict all dividends or loans to the Company. In addition to the borrowing base structure which requires Enserco to maintain certain levels of tangible net worth and net working capital, the amendment to the covenants restricted 100% of Enserco's net assets. Therefore, upon review of this covenant at December 31, 2009, restricted net assets at Enserco total $205.8 million for this stand-alone Enserco Credit Facility. The amendment to the covenants expired on December 31, 2009, and is not a requirement under the facility subsequent to December 31, 2009.

Off-Balance Sheet Arrangements

Guarantees

We provide various guarantees supporting certain of our subsidiaries under specified agreements or transactions. At December 31, 2009, we had guarantees totaling $197.4 million in place. Of the $197.4 million, $181.9 million was related to performance obligations under subsidiary contracts and $15.5 million was related to indemnification for reclamation and surety bonds of subsidiaries. For more information on these guarantees, see Note 20 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

As of December 31, 2009, we had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2009	Year Expiring
Guarantee obligations of Enserco under an agency agreement	$7,000	2010
	70,000	Ongoing

Guarantees for payment of obligations arising from commodity-related physical and financial transactions by Black Hills Utility Holdings		
Guarantees for payment obligations arising from purchase contracts for four gas turbines for Black Hills Colorado IPP	62,090	2011
Guarantees for payment obligations arising from purchase contracts for two gas turbines for Colorado Electric	42,742	2010
Indemnification for subsidiary reclamation/surety bonds	15,532	Ongoing
	$ 197,364	

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At December 31, 2009, we had outstanding letters of credit of $209.3 million on the Corporate Credit Facility and $103.0 million on the Enserco Credit Facility, respectively.

Variable Interest Entities

In 2003, our Black Hills Wyoming subsidiary entered into an agreement with Wygen Funding, Limited Partnership (the variable interest entity) to lease the Wygen I plant. We were considered the "primary beneficiary" of this arrangement and, therefore, we included the VIE in our consolidated financial statements. The initial term of the lease was five years and included a purchase option equal to the adjusted acquisition cost, which was essentially equal to the cost of the plant. We guaranteed the obligations of Black Hills Wyoming under the lease agreement.

At the end of the initial lease term in June 2008, we elected to purchase the Wygen I plant at an adjusted acquisition cost of $133.1 million. In conjunction with this purchase, we retired $128.3 million of Wygen I project debt through borrowings on our revolving credit facility, and extinguished the $111.0 million guarantee obligation under the Wygen I lease. Since the plant and its financial activities were previously consolidated into our financial statements, the transaction had minimal impact on our consolidated financial statements.

Cash Flow Activities

2009

Cash flows from operations of $270.5 million increased $124.9 million from the prior year amount, due primarily to a $130.8 million increase in income from continuing operations and the following:

- An $84.7 million increase in cash flows from working capital changes. This increase primarily resulted from a $129.8 million increase from lower accounts receivable and other current assets offset by a $31.7 million decrease from lower accounts payable and other current liabilities. A $13.4 million decrease in materials, supplies and fuel primarily relates to natural gas held in storage by Energy Marketing and the regulated Gas Utilities which fluctuates based on seasonal trends and economic decisions reflecting current market conditions;

- A $14.0 million increase in depreciation, depletion and amortization expense;

- A $55.7 million pre-tax unrealized gain related to interest rate swaps marked-to-market through earnings compared to a $94.4 million unrealized loss in 2008;

- A $64.2 million increase in cash flows from the net change in derivative assets and liabilities primarily from derivatives associated with normal operations of our gas and oil marketing business and our Oil and Gas segment related to commodity price fluctuations;

- A $39.7 million increase in cash flows from regulatory assets and liabilities primarily resulting from deferred gas adjustments for our regulated Gas Utilities segment and employee benefits at our regulated Electric Utilities and regulated Gas Utilities;

- A $26.0 million decrease to adjust for the non-cash effect of the gain on sale of operating assets. This gain relates to the sale of 23.5% interest in the Wygen I power plant to MEAN for which we received $51.9 million included in investing activities;

- A $48.5 million decrease for non-cash ceiling test impairment charges to write down the net carrying value of our natural gas and crude oil properties due to low year-end commodity prices; and

- A $37.7 million increase from deferred income taxes primarily the result of accelerated deductions associated with property, plant and equipment.

Net cash outflows from investing activities of $269.8 million, included the following:

- Cash outflows of $346.9 million of property, plant and equipment additions. Significant additions during 2009 included approximately $61.9 million for Wygen III, and approximately $64.5 million for construction of 380 MW of natural gas-fired electric generation in Colorado;

- Cash inflows of $51.9 million of proceeds from the sale of the 23.5% ownership interest in the Wygen I power plant to MEAN;

- Cash inflows of $32.8 million of proceeds from the sale of the 25% ownership interest in the Wygen III power plant to MDU; and

- Cash inflows of $7.9 million for working capital adjustments on the purchase price allocation for the Aquila Transaction.

Net cash outflows from financing activities of $56.3 million included the following:

- Net cash outflows of $539.3 million for net re-payment on the Corporate Credit Facility and the Acquisition Facility;

- Cash outflows of $55.1 million of cash dividends on common stock;

- Cash inflows of $248.5 million from the proceeds from issuance of senior unsecured five year notes;

- Cash inflows of $180.0 million from the proceeds of first mortgage bonds; and

- Cash inflows of $114.6 million from the proceeds of a Black Hills Wyoming project financing.

2008

Cash flows from operations of $145.6 million decreased $110.6 million from the prior year amount, due primarily to a $127.4 million decrease in income from continuing operations and by the following:

- A $98.5 million decrease in cash flows from the change in operating assets and liabilities. The primary changes include changes in working capital accounts and current tax effects of both the IPP Transaction and the Aquila Transaction;

- Higher depreciation, depletion and amortization expense of $35.5 million;

- A $94.4 million pre-tax unrealized loss related to interest rate swaps marked-to-market through earnings; and

- A $91.8 million pre-tax ceiling test impairment charge to write down the net carrying value of our natural gas and crude oil properties due to low year-end commodity prices.

We had net cash outflows from investing activities of $457.1 million, including:

- The acquisition costs of $938.4 million for the Aquila Transaction; and

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Approximately $328.9 million of property, plant and equipment additions. Significant additions during 2008 included approximately $99.3 million for Wygen III, approximately $75.3 million for development drilling at our oil and gas properties, and $16.9 million for the acquisition of an additional non-operated interest in a Wyoming oil and gas property.

Partially offsetting the cash outflows from investing activities was $835.6 million of cash received for the IPP Transaction.

We had net cash inflows from financing activities of $398.7 million primarily due to the following:

- A $382.8 million increase in borrowings under the Acquisition Facility, in conjunction with the Aquila Transaction; and
- A $284.0 million increase in borrowings on our revolving bank facility.

Partially offsetting the cash inflows from financing activities were the following:

- The payment of $53.7 million of cash dividends on common stock;
- Repayment of $130.3 million of long-term debt, including $128.3 million for the Wygen I project level debt; and
- Repayment of $73.9 million for Colorado IPP project-level debt, which was retired as part of the IPP Transaction and is included in financing activities of discontinued operations.

Market Risk Disclosures

Our activities expose us to a number of risks in the normal operation of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and counterparty risk. We have developed policies, processes, systems, and controls to manage and mitigate these risks.

Market risk is the potential loss that might occur as a result of an adverse change in market price or rate. We are exposed to the following market risks:

- Commodity price risk associated with our marketing business, our natural long position with crude oil and natural gas reserves and production, and fuel procurement for certain of our gas-fired generation assets;
- Interest rate risk associated with our variable rate credit facilities and our project financing floating rate debt as described in Notes 8 and 9 of our Notes to Consolidated Financial Statements; and
- Foreign currency exchange risk associated with our natural gas marketing business transacted in Canadian dollars.

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

To manage and mitigate these identified risks, we have adopted the BHCRPP. These policies have been approved by our Executive Risk Committee and reviewed by our Board of Directors. These policies include governance, control infrastructure, authorized commodities and trading instruments, prohibited activities, employee conduct, etc. The Executive Risk Committee, which includes senior level executives, meets on a regular basis to review our business and credit activities and to ensure that these activities are conducted within the authorized policies.

Utilities

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

As allowed or required by state utility commissions, we have entered into certain exchange-traded natural gas futures, options and basis swaps to reduce our customers' underlying exposure to volatility of natural gas prices. These transactions are considered derivatives and are marked-to-market. Gains or losses, as well as option premiums on these transactions, are recorded in Regulatory assets or Regulatory liabilities.

The fair value of our Gas Utilities derivative contracts are summarized below (in thousands):

	December 31, 2009	December 31, 2008
Net derivative liabilities	$ (1,511)	$ (7,444)
Cash collateral	3,789	8,744
	$ 2,278	$ 1,300

Trading Activities

Natural Gas and Crude Oil Marketing

We have a natural gas and crude oil marketing business specializing in producer services, end-use origination and wholesale marketing that conducts business in the western and mid-continent regions of the United States and Canada. For producer services our main objective is to provide value in the supply chain by acting as the producer's "marketing arm" for wellhead purchases, scheduling services, imbalance management, risk management services and transportation management. We accomplish this goal through industry experience, extensive contacts, transportation and risk management expertise, trading skills and personal attention. Our end-use origination efforts focus on supplying and providing electricity generators and industrial customers with flexible options to procure their energy inputs and asset optimization services to these large end-use consumers of natural gas. Our wholesale marketing activity has two functions: support the efforts of producer services and end-use origination groups, and marketing and trading natural gas and crude oil.

To effectively manage our producer services, end-use origination and wholesale marketing portfolios, we enter into forward physical commodity contracts, financial derivative instruments including over-the-counter swaps and options, and storage and transportation agreements.

We conduct our energy marketing business activities within the parameters as defined and allowed in the BHCRPP and further delineated in the energy marketing Risk Management Policies and Procedures as approved by our Executive Risk Committee.

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Monitoring and Reporting Market Risk Exposures

We use a number of quantitative tools to measure, monitor and limit our exposure to market risk in our natural gas and oil marketing portfolio. We limit and monitor our market risk through established limits on the nominal size of positions based on type of trade, location and duration. Such limits include those on fixed price, basis, index, storage, transportation and foreign exchange positions.

Our market risk limits are monitored by our Risk Management function to ensure compliance with our stated risk limits. The Risk Management function operates independently from our Energy Marketing Group. The limits are measured, monitored and regularly reported to and reviewed by our Executive Risk Committee.

Daily risk management activities include reviewing positions in relation to established position limits, assessing changes in daily mark-to-market and other non-statistical risk management techniques.

The contract or notional amounts, terms and mark-to-market values of our natural gas and crude oil marketing and derivative commodity instruments at December 31, 2009 and 2008, are set forth in Note 3 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Fair Value of Energy Marketing Positions

The following table provides a reconciliation of activity in our natural gas and crude oil marketing portfolio that has been recorded at fair value in accordance with GAAP during the year ended December 31, 2009 (in thousands):

Total fair value of energy marketing positions marked-to-market at December 31, 2008	$28,447	(a)
Net cash settled during the period on positions that existed at December 31, 2008	(41,331)	
Change in fair value due to change in assumptions	-	
Unrealized gain on new positions entered during the period and still existing at December 31, 2009	7,580	
Realized gain on positions that existed at December 31, 2008 and were settled during the period	(2,798)	
Change in cash collateral(b)	19,043	
Unrealized gain on positions that existed at December 31, 2008 and still exist at December 31, 2009	8,580	
Total fair value of energy marketing positions at December 31, 2009	$19,521	(a)

(a) The fair value of energy marketing positions consists of the mark-to-market values of derivative assets/liabilities and market value adjustments to natural gas inventory that has been designated as a hedged item as part of a fair value hedge, as follows (in thousands):

	December 31, 2009	December 31, 2008
Net derivative assets	$ 17,084	$ 54,117
Cash collateral	2,728	(16,315)
Market adjustment recorded in material, supplies and fuel	(291)	(9,355)
Total fair value of energy marketing positions marked-to-market	$ 19,521	$ 28,447

(b) In accordance with accounting standards for balance sheet offsetting when the right of offset exists under a master netting agreement, we offset our cash collateral with our trading positions effective January 1, 2008. See Note 3 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

To value the assets and liabilities for our outstanding derivative contracts, we use the fair value methodology outlined in accounting standards for fair value measurements and disclosures. See Note 4 of the Notes to Consolidated Financial Statements in this 2009 Annual Report on Form 10-K.

The sources of fair value measurements were as follows (in thousands):

Source of Fair Value	Maturities Less than 1 year	Maturities 1 - 2 years	Total Fair Value
Level 1	$-	$-	$-
Level 2	14,451	4,650	19,101
Level 3	(939)	(1,078)	(2,017)
Cash collateral	2,728	-	2,728
Market value adjustment for inventory (see footnote (a) above)	(291)	-	(291)
Total fair value of our energy marketing positions	$15,949	$3,572	$19,521

GAAP restricts mark-to-market accounting treatment primarily to only those contracts that meet the definition of a derivative under accounting standards for derivatives and hedges. Therefore, the above reconciliation does not present a complete picture of our overall portfolio of trading activities or our expected cash flows from energy trading activities. In our natural gas and crude oil marketing operations, we often employ strategies that include utilizing derivative contracts along with inventory, storage and transportation positions to accomplish the objectives of our producer services, end-use origination and wholesale marketing groups. Except in circumstances when we are able to designate transportation, storage or inventory positions as part of a fair value hedge, accounting standards for derivatives generally do not allow us to mark our inventory, transportation or storage positions to market. The result is that while a significant majority of our energy marketing positions are fully economically hedged, we are required to mark some parts of our overall strategies (the derivatives) to market value, but are generally precluded from marking the rest of our economic hedges (transportation, inventory or storage) to market. Volatility in reported earnings and derivative positions should be expected given these accounting requirements. The table below references non-GAAP measures that quantify these positions.

The following table presents a reconciliation of our energy marketing positions recorded at fair value under GAAP to a non-GAAP measure of the fair value of our energy marketing forward book wherein all forward trading positions are marked-to-market (in thousands):

	December 31, 2009	December 31, 2008
Fair value of our energy marketing positions marked-to-market in accordance with GAAP (see footnote (a) above)	$19,521	$28,447
Market value adjustments for inventory, storage and transportation positions that are not marked-to-market under GAAP	(2,916)	45,192
Fair value of all forward positions (non-GAAP)	16,605	73,639
Cash collateral included in GAAP fair value	(2,728)	16,315
Fair value of all forward positions excluding cash collateral (non-GAAP)*	$13,877	$89,954

*We consider this measure a Non-GAAP financial measure. This measure is presented because we believe it provides a more comprehensive view to our investors of our energy trading activities and thus a better understanding of these activities than would be presented by the GAAP measure alone.

Activities Other than Trading

Oil and Gas Exploration and Production

We produce natural gas and crude oil through our exploration and production activities. Our reserves are natural "long" positions, or unhedged open positions, and introduce commodity price risk and variability in our cash flows. We employ risk management methods to mitigate this commodity price risk and preserve our cash flows. We have adopted guidelines covering hedging for our natural gas and crude oil production. These guidelines have been approved by our Executive Risk Committee and reviewed by our Board of Directors.

To mitigate commodity price risk and preserve cash flows, we primarily use over-the-counter swaps and options. Our hedging policy allows up to 75% of our natural gas and 100% of our crude oil production from proven producing reserves to be hedged for a period up to two years in the future. Our hedging strategy is conducted from an enterprise-wide risk perspective; accordingly, we might not externally hedge a portion of our natural gas production when we have offsetting price risk for the fuel requirements of certain of our power generating activities.

The Company has entered into agreements to hedge a portion of its estimated 2010, 2011 and 2012 natural gas and crude oil production. The hedge agreements in place are as follows:

Natural Gas

Location	Transaction Date	Hedge Type	Term	Volume (MMBtu/day)	Price
CIG	01/03/2008	Swap	01/10 - 03/10	2,000	$7.49
NWR	01/03/2008	Swap	01/10 - 03/10	1,500	$7.50
AECO	01/03/2008	Swap	11/09 - 03/10	1,000	$8.07
San Juan El Paso	01/23/2008	Swap	01/10 - 03/10	5,000	$7.50
San Juan El Paso	02/28/2008	Swap	01/10 - 03/10	3,000	$8.55
San Juan El Paso	04/09/2008	Swap	04/10 - 06/10	5,000	$7.26
San Juan El Paso	04/30/2008	Swap	04/10 - 06/10	2,500	$7.65
AECO	08/20/2008	Swap	04/10 - 06/10	1,000	$7.73
San Juan El Paso	08/20/2008	Swap	07/10 - 09/10	5,000	$7.74
AECO	08/20/2008	Swap	07/10 - 09/10	1,000	$7.88
AECO	10/24/2008	Swap	10/10 - 12/10	1,000	$7.05
San Juan El Paso	12/19/2008	Swap	04/10 - 06/10	1,500	$5.39
San Juan El Paso	12/19/2008	Swap	07/10 - 09/10	3,000	$5.95
San Juan El Paso	12/19/2008	Swap	10/10 - 12/10	5,000	$5.89
CIG	01/26/2009	Swap	04/10 - 06/10	2,000	$4.45
CIG	01/26/2009	Swap	07/10 - 09/10	2,000	$4.47
CIG	01/26/2009	Swap	10/10 - 12/10	2,000	$4.68
CIG	01/26/2009	Swap	01/11 - 03/11	2,000	$6.00
NWR	01/26/2009	Swap	01/11 - 03/11	2,000	$6.05
San Juan El Paso	01/26/2009	Swap	01/11 - 03/11	5,000	$6.38
San Juan El Paso	02/13/2009	Swap	01/11 - 03/11	2,500	$6.16
San Juan El Paso	02/13/2009	Swap	10/10 - 12/10	3,000	$5.35
NWR	02/13/2009	Swap	04/10 - 12/10	1,000	$4.20
AECO	03/04/2009	Swap	01/11 - 03/11	1,000	$5.95
NWR	03/04/2009	Swap	04/10 - 06/10	1,000	$4.06

NWR	03/04/2009	Swap	07/10 - 09/10	1,000	$4.12
NWR	03/04/2009	Swap	10/10 - 12/10	1,000	$4.55
NWR	03/20/2009	Swap	01/10 - 03/10	500	$4.58
San Juan El Paso	03/20/2009	Swap	01/10 - 03/10	1,000	$4.87
San Juan El Paso	06/02/2009	Swap	04/11 - 06/11	5,000	$5.99
AECO	06/02/2009	Swap	04/11 - 06/11	800	$5.89
NWR	06/02/2009	Swap	04/11 - 06/11	1,500	$5.54

San Juan El Paso	06/25/2009	Swap	04/11 - 06/11	2,500	$5.55
CIG	06/25/2009	Swap	04/11 - 06/11	1,750	$5.33
CIG	09/02/2009	Swap	07/11 - 09/11	500	$5.32
NWR	09/02/2009	Swap	07/11 - 09/11	500	$5.32
San Juan El Paso	09/02/2009	Swap	07/11 - 09/11	2,500	$5.54
CIG	09/25/2009	Swap	07/11 - 09/11	500	$5.59
NWR	09/25/2009	Swap	07/11 - 09/11	1,000	$5.59
AECO	09/25/2009	Swap	07/11 - 09/11	500	$5.76
San Juan El Paso	09/25/2009	Swap	07/11 - 09/11	5,000	$5.91
San Juan El Paso	10/09/2009	Swap	01/10 - 03/10	2,000	$5.42
San Juan El Paso	10/09/2009	Swap	04/10 - 06/10	750	$5.29
San Juan El Paso	10/09/2009	Swap	07/10 - 09/10	1,000	$5.65
San Juan El Paso	10/09/2009	Swap	10/10 - 12/10	1,000	$5.90
San Juan El Paso	10/23/2009	Swap	10/11 - 12/11	2,500	$6.23
NWR	10/23/2009	Swap	10/11 - 12/11	1,500	$6.12
San Juan El Paso	10/23/2009	Swap	01/11 - 03/11	1,000	$6.59
AECO	12/11/2009	Swap	10/11 - 12/11	500	$6.27
CIG	12/11/2009	Swap	10/11 - 12/11	1,500	$6.03
San Juan El Paso	12/11/2009	Swap	10/11 - 12/11	5,000	$6.15
San Juan El Paso	01/08/2010	Swap	01/12 - 03/12	2,500	$6.38
NWR	01/08/2010	Swap	01/12 - 03/12	1,500	$6.47
AECO	01/08/2010	Swap	01/12 - 03/12	500	$6.32
CIG	01/08/2010	Swap	01/12 - 03/12	1,500	$6.43
San Juan El Paso	01/25/2010	Swap	01/12 - 03/12	5,000	$6.44

Crude Oil

Location	Transaction Date	Hedge Type	Term	Volume (Bbls/month)	Price
NYMEX	01/03/2008	Put	01/10 - 03/10	5,000	$80.00
NYMEX	01/03/2008	Swap	01/10 - 03/10	5,000	$88.70
NYMEX	01/23/2008	Swap	01/10 - 03/10	5,000	$82.90
NYMEX	02/28/2008	Put	01/10 - 03/10	5,000	$85.00
NYMEX	04/09/2008	Swap	04/10 - 06/10	5,000	$99.60
NYMEX	04/30/2008	Put	04/10 - 06/10	5,000	$85.00
NYMEX	05/29/2008	Put	04/10 - 06/10	5,000	$105.00
NYMEX	07/16/2008	Swap	04/10 - 06/10	5,000	$135.10
NYMEX	07/16/2008	Swap	07/10 - 09/10	5,000	$134.90
NYMEX	08/20/2008	Put	07/10 - 09/10	5,000	$90.00
NYMEX	09/03/2008	Put	07/10 - 09/10	5,000	$90.00
NYMEX	10/24/2008	Put	07/10 - 09/10	5,000	$60.00
NYMEX	12/05/2008	Swap	10/10 - 12/10	5,000	$65.20
NYMEX	01/26/2009	Swap	10/10 - 12/10	5,000	$60.15
NYMEX	01/26/2009	Swap	01/11 - 03/11	5,000	$60.90
NYMEX	02/13/2009	Swap	01/11 - 03/11	5,000	$60.05
NYMEX	03/04/2009	Swap	10/10 - 12/10	5,000	$55.80
NYMEX	03/04/2009	Swap	01/11 - 03/11	5,000	$57.00
NYMEX	04/08/2009	Swap	04/11 - 06/11	5,000	$68.80
NYMEX	04/23/2009	Swap	04/11 - 06/11	5,000	$65.10
NYMEX	06/02/2009	Swap	10/10 - 12/10	5,000	$74.30
NYMEX	06/02/2009	Swap	01/11 - 03/11	5,000	$75.05
NYMEX	06/02/2009	Swap	04/11 - 06/11	5,000	$75.86
NYMEX	06/04/2009	Put	04/11 - 06/11	5,000	$67.00
NYMEX	09/02/2009	Swap	07/11 - 09/11	5,000	$75.10
NYMEX	09/02/2009	Put	07/11 - 09/11	5,000	$63.00
NYMEX	09/29/2009	Swap	07/11 - 09/11	5,000	$74.00
NYMEX	10/06/2009	Put	07/11 - 09/11	5,000	$65.00
NYMEX	10/09/2009	Swap	10/11 - 12/11	5,000	$79.35
NYMEX	10/23/2009	Put	10/11 - 12/11	5,000	$75.00
NYMEX	11/19/2009	Swap	04/11 - 06/11	1,000	$85.35
NYMEX	11/19/2009	Swap	07/11 - 09/11	1,500	$85.95
NYMEX	11/19/2009	Swap	10/11 - 12/11	5,000	$87.50
NYMEX	01/08/2010	Swap	04/10 - 06/10	5,000	$84.30
NYMEX	01/08/2010	Swap	07/10 - 09/10	5,000	$85.60
NYMEX	01/08/2010	Swap	10/10 - 12/10	5,000	$86.88
NYMEX	01/08/2010	Put	10/11 - 12/11	6,000	$75.00
NYMEX	01/08/2010	Put	01/12 - 03/12	5,000	$75.00
NYMEX	01/25/2010	Swap	01/12 - 03/12	5,000	$83.30

The hedge agreements entered into by the Company as of December 31, 2009 had a fair value of approximately $4.5 million as of December 31, 2009.

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Wholesale Power

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

Financing Activities

We engage in activities to manage risks associated with changes in interest rates. We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations. At December 31, 2009, we had $150.0 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 7 years. These swaps have been designated as hedges in accordance with accounting standards for derivatives and hedges and accordingly their mark-to-market adjustments are recorded in Accumulated other comprehensive loss on the Consolidated Balance Sheet.

We also have interest rate swaps with a notional amount of $250.0 million which were entered into for the purpose of hedging interest rate movements that would impact long-term financings that were originally expected to occur in 2008. The swaps were originally designated as cash flow hedges and the mark-to-market value was recorded in "Accumulated other comprehensive loss" on the Consolidated Balance Sheet. Based on credit market conditions that transpired during the fourth quarter of 2008, we determined it was probable that the forecasted long-term debt financings would not occur in the time period originally specified and as a result, the swaps were no longer effective hedges and the hedge relationships were de-designated. Mark-to-market adjustments on the swaps are now recorded within the income statement and during 2009 we recorded a $55.7 million pre-tax unrealized mark-to-market gain to earnings, while in 2008 we recorded a $94.4 million pre-tax unrealized mark-to-market charge to earnings. These swaps are ten and twenty year swaps which 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 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 stated termination dates.

Further details of the swap agreements are set forth in Note 3 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

On December 31, 2009 and 2008, our interest rate swaps and related balances were as follows (dollars in thousands):

December 31, 2009	Notional	Weighted Average Fixed Interest Rate	Maximum Terms in Years	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)	Pre-tax Income (Loss)
Interest rate swaps	$150,000	5.04 %	7.0	$-	$-	$ 6,342	$ 9,075	$ (15,417)	$ -
Interest rate swaps	$250,000	5.67 %	1.0	$-	$-	$ 38,787	$ -	$ -	$ 55,653
	$400,000			$-	$-	$ 45,129	$ 9,075	$ (15,417)	$ 55,653
December 31, 2008									
Interest rate swaps	$150,000	5.04 %	8.00	$-	$-	$ 5,740	$ 22,495	$ (28,235)	$ -
Interest rate swaps	250,000	5.67 %	1.00	-	-	94,440	-	$ -	$ (94,440)
	$400,000			$-	$-	$ 100,180	$ 22,495	$ (28,235)	$ (94,440)

Based on December 31, 2009 market interest rates and balances, a loss of approximately $6.3 million would be realized and reported in pre-tax earnings during the next twelve months. Estimated and realized losses will likely change during the next twelve months as market interest rates change.

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

	2010	2011	2012	2013	2014	Thereafter	Total
Long-term debt							
Fixed rate (a)	$ 32,096	$ 2,116	$ 2,028	$ 226,955	$ 258,405	$ 389,925	$ 911,525
Average interest rate	8.16 %	9.70 %	9.53 %	6.52 %	8.90 %	6.57 %	7.29 %
Variable rate	$ 3,149	$ 5,020	$ 2,400	$ 3,973	$ 6,023	$ 119,290	$ 139,855
Average interest rate	3.49 %	3.49 %	3.49 %	3.49 %	3.49 %	3.12 %	3.18 %
Total long-term debt	$ 35,245	$ 7,136	$ 4,428	$ 230,928	$ 264,428	$ 509,215	$ 1,051,380

Average interest rate	7.75	%	5.33	%	6.25	%	6.47	%	8.77	%	5.77	%	6.74	%

(a) Excludes unamortized premium or discount.

Credit Risk

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

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 parental guarantees, prepayments, letters of credit, and other security agreements.

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

At December 31, 2009, approximately 77% of our credit exposure (exclusive of retail customers of our regulated utilities) was with investment grade companies. The remaining credit exposure is with non-investment grade or non-rated counterparties, of which a portion was supported through letters of credit, prepayments, or parental guarantees.

Foreign Exchange Contracts

Our natural gas and crude oil marketing subsidiary conducts its business in the United States and Canada. Transactions in Canada are generally transacted in Canadian dollars, which creates exchange rate risk. To mitigate this risk, we enter into forward currency exchange contracts to offset earnings volatility from changes in exchange rates between the Canadian and United States dollars. At December 31, 2009, we had no outstanding forward exchange contracts. At December 31, 2008, we had outstanding forward exchange contracts to purchase approximately $52.0 million Canadian dollars. These contracts had a fair value of $(0.2) million at December 31, 2008, and have been recorded as Derivative assets/liabilities on the accompanying Consolidated Balance Sheets.

New Accounting Pronouncements

See Note 2 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for information on new accounting standards adopted in 2009 or pending adoption.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Management's Report on Internal Control over Financial Reporting

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

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2009, based on the criteria set forth in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on our evaluation we have concluded that our internal control over financial reporting was effective as of December 31, 2009.

Deloitte & Touche, LLP, an independent registered public accounting firm, as auditors of Black Hills Corporation's financial statements, has issued an attestation report on the effectiveness of Black Hills Corporation's internal control over financial reporting as of December 31, 2009. Deloitte & Touche LLP's report on Black Hills Corporation's internal control over financial reporting is included herein.

Black Hills Corporation

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of Black Hills Corporation and subsidiaries (the "Company") as of December 31, 2009, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and the financial statement schedules as of and for the year ended December 31, 2009, of the Company and our report dated February 26, 2010, expressed an unqualified opinion on those consolidated financial statements and financial statement schedules and included an explanatory paragraph regarding the Company's change in an accounting principle.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 26, 2010

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Black Hills Corporation and subsidiaries (the "Company") as of December 31, 2009 and 2008, and the related consolidated statements of income, common stockholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2009. Our audits also included the financial statement schedules listed in the Index at Item 15. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Black Hills Corporation and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, the Company changed certain items related to its oil and gas operations in 2009.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2009, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2010 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 26, 2010

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

	2009	2008	2007
	(in thousands, except share and per share amounts)		
Revenues:			
Operating revenues	$1,269,578	$1,005,790	$574,838
Operating expenses:			
Fuel and purchased power	652,750	449,742	161,006
Operations and maintenance	152,742	121,264	68,755
Gain on sale of operating assets	(25,971)	-	-
Administrative and general	154,187	138,568	111,337
Depreciation, depletion and amortization	121,297	107,263	71,767
Impairment of long-lived assets	43,301	91,782	3,315
Taxes, other than income taxes	44,440	41,294	32,943
Total operating expenses	1,142,746	949,913	449,123
Operating income	126,832	55,877	125,715
Other income (expense):			
Interest expense	(84,690)	(54,123)	(25,181)
Unrealized gain (loss) on interest rate swaps	55,653	(94,440)	-
Interest income	1,612	2,176	3,565
Allowance for funds used during construction - equity	5,891	3,835	4,803
Other expense	(513)	(187)	(347)
Other income	5,943	1,064	761
Total other expense	(16,104)	(141,675)	(16,399)
Income (loss) from continuing operations before non-controlling interest and income taxes	110,728	(85,798)	109,316
Equity in earnings (loss) of unconsolidated subsidiaries	1,343	4,366	(1,231)
Income tax (expense) benefit	(33,315)	29,395	(32,427)
Income (loss) from continuing operations	78,756	(52,037)	75,658
Income from discontinued operations, net of income taxes	2,799	157,247	23,491
Net income	81,555	105,210	99,149
Net income attributable to non-controlling interest	-	(130)	(377)
Net income available for common stock	$81,555	$105,080	$98,772
Earnings (loss) per share of common stock:			
Basic-			
Continuing operations	$2.04	$(1.37)	$2.04
Discontinued operations	0.07	4.12	0.63
Non-controlling interest	-	-	(0.01)
Total	$2.11	$2.75	$2.66
Diluted-			
Continuing operations	$2.04	$(1.37)	$2.02
Discontinued operations	0.07	4.12	0.63

Non-controlling interest	-	-	(0.01)
Total	$2.11	$2.75	$2.64
Weighted average common shares outstanding:			
Basic	38,614	38,193	37,024
Diluted	38,684	38,193	37,414

The accompanying notes to consolidated financial statements are an integral part of these consolidated financial statements.

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS

At December 31,	2009	2008
	(in thousands, except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$112,901	$168,491
Restricted cash	17,502	-
Accounts receivable, net	274,489	357,404
Materials, supplies and fuel	123,322	118,021
Derivative assets, current	37,747	73,068
Income tax receivable	2,031	20,269
Deferred income taxes	4,523	10,244
Regulatory assets, current	25,085	35,390
Other current assets	27,270	16,380
Assets of discontinued operations	-	246
Total current assets	624,870	799,513
Investments	18,524	22,764
Property, plant and equipment	2,975,993	2,705,492
Less accumulated depreciation and depletion	(815,263)	(683,332)
Total property, plant and equipment, net	2,160,730	2,022,160
Other assets:		
Goodwill	353,734	359,290
Intangible assets, net	4,309	4,884
Derivative assets, non-current	3,777	9,799
Regulatory assets, non-current	135,578	143,705
Other assets	16,176	17,774
Total other assets	513,574	535,452
TOTAL ASSETS	$3,317,698	$3,379,889
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$229,352	$288,907
Accrued liabilities	151,504	134,940
Derivative liabilities, current	57,166	118,657
Regulatory liabilities, current	7,092	5,203
Notes payable	164,500	703,800
Current maturities of long-term debt	35,245	2,078
Liabilities of discontinued operations	-	88
Total current liabilities	644,859	1,253,673
Long-term debt, net of current maturities	1,015,912	501,252
Deferred credits and other liabilities:		
Deferred income taxes, non-current	262,034	223,607
Derivative liabilities, non-current	11,999	22,025
Regulatory liabilities, non-current	42,458	38,456
Benefit plan liabilities	140,671	159,034
Other deferred credits and other liabilities	114,928	131,306
Total deferred credits and other liabilities	572,090	574,428

Commitments and contingencies (See Notes 3, 8, 9, 10, 13, 18, 19 and 20)		
Stockholders' equity:		
Common stock equity-		
Common stock $1 par value; 100,000,000 shares authorized; issued: 38,977,526 shares at 2009 and 38,676,054 shares at 2008	38,978	38,676
Additional paid-in capital	591,390	584,582
Retained earnings	473,857	447,453
Treasury stock at cost - 8,834 shares at 2009 and 40,183 shares at 2008	(224)	(1,392)
Accumulated other comprehensive loss	(19,164)	(18,783)
Total stockholders' equity	1,084,837	1,050,536
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$3,317,698	$3,379,889

The accompanying notes to consolidated financial statements are an integral part of these consolidated financial statements.

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended December 31,	2009	2008	2007
		(in thousands)	
Operating activities:			
Net income	$ 81,555	$ 105,210	$ 99,149
(Income) from discontinued operations, net of tax	(2,799)	(157,247)	(23,491)
Income (loss) from continuing operations	78,756	(52,037)	75,658
Adjustments to reconcile income (loss) from continuing operations to net cash provided by operating activities -			
Depreciation, depletion and amortization	121,297	107,263	71,767
Impairment of long-lived assets	43,301	91,782	3,315
Gain on sale of operating assets	(25,971)	-	-
Stock compensation	3,983	2,657	4,585
Unrealized mark-to-market (gain) loss on interest rate swaps	(55,653)	94,440	-
Earnings of associated companies	(1,343)	(2,581)	4,954
Allowance for funds used during construction - equity	(5,891)	(3,835)	(4,803)
Derivative fair value adjustments	27,362	(36,847)	(12,354)
Deferred income taxes	39,743	2,058	31,409
Other non-cash adjustments	11,306	6,720	3,497
Change in operating assets and liabilities-			
Materials, supplies and fuel	1,078	14,525	18,197
Accounts receivable and other current assets	78,886	(50,955)	(27,510)
Accounts payable and other current liabilities	(53,157)	(21,453)	49,897
Regulatory assets	2,598	(36,400)	(5,143)
Regulatory liabilities	1,265	526	(4,290)
Other operating activities	26	11,725	2,537
Net cash provided by operating activities of continuing operations	267,586	127,588	211,716
Net cash provided by operating activities of discontinued operations	2,916	18,053	44,572
Net cash provided by operating activities	270,502	145,641	256,288
Investing activities:			
Property, plant and equipment additions	(346,872)	(328,922)	(205,213)
Payment for acquisition of net assets, net of cash acquired	-	(938,423)	-
Proceeds from sale of business operations	-	835,592	-
Proceeds from sale of ownership interest in plants	84,661	-	-
Working capital adjustment - Aquila Transaction	7,880	-	-
Other investing activities	(15,492)	4,537	(3,360)
Net cash used in investing activities of continuing operations	(269,823)	(427,216)	(208,573)
Net cash used in investing activities of discontinued operations	-	(29,836)	(55,908)
Net cash used in investing activities	(269,823)	(457,052)	(264,481)
Financing activities:			
Dividends paid on common stock	(55,151)	(53,663)	(50,300)

Common stock issued		4,819			2,683			150,787	
Decrease in short-term borrowings		(1,125,300)			1,150,300			(444,608)	
Increase in short-term borrowings		586,000			(483,500)			336,108	
Long-term debt - issuance		543,069			-			110,000	
Long-term debt - repayments		(2,173)			(130,297)			(35,033)	
Other financing activities		(7,574)			(12,907)			(2,178)	
Net cash (used in) provided by financing activities of continuing operations		(56,310)			472,616			64,776	
Net cash used in financing activities of discontinued operations		-			(73,928)			(12,858)	
Net cash (used in) provided by financing activities		(56,310)			398,688			51,918	
(Decrease) increase in cash and cash equivalents		(55,631)			87,277			43,725	
Cash and cash equivalents:									
Beginning of year		168,532			81,255	(b)		37,530	(c)
End of year	$	112,901		$	168,532	(a)	$	81,255	(b)

See Note 16 for supplemental disclosure of cash flow information

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(a) Includes approximately $0.04 million of cash included in assets of discontinued operation.
(b) Includes approximately $4.4 million of cash included in the assets of discontinued operations.
(c) Includes approximately $5.0 million of cash included in the assets of discontinued operations.

The accompanying notes to consolidated financial statements are an integral part of these consolidated financial statements.

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY
AND COMPREHENSIVE INCOME

	Year Ended December 31,		
	2009	2008	2007
	(in thousands)		
Common stock:			
Balance beginning of year	$38,676	$37,842	$33,405
Issuance of common stock:			
Stock options	79	83	164
Performance share plan	-	35	4
Restricted stock	80	89	56
Earn-out litigation	-	594	-
Equity offering	-	-	4,171
Dividend reinvestment and stock purchase plan	143	-	-
Other common stock	-	33	42
Balance end of year	38,978	38,676	37,842
Additional paid-in capital:			
Balance beginning of year	584,582	560,475	409,826
Issuance of common stock:			
Stock options	1,735	2,333	5,566
Performance share plan	721	388	1,119
Restricted stock	2,254	1,134	1,829
Earn-out litigation	-	19,100	-
Equity offering	-	-	141,474
Dividend reinvestment and stock purchase plan	2,098	-	-
Other additional paid-in capital	-	1,152	661
Balance end of year	591,390	584,582	560,475
Retained earnings:			
Balance beginning of year	447,453	397,393	348,245
Net income available for common stock	81,555	105,080	98,772
Dividends on common stock	(55,151)	(53,663)	(50,300)
Cumulative effect of change in accounting principle	-	(1,357)	676
Balance end of year	473,857	447,453	397,393
Treasury stock:			
Balance beginning of year	(1,392)	(1,347)	(161)
Forfeitures of unvested restricted stock	(149)	(528)	(28)
Share withholding for payment of taxes associated with vesting of restricted shares and stock option exercise stock swaps	(546)	(662)	(643)
Equity compensation issuances and other	1,863	1,145	(515)
Balance end of year	(224)	(1,392)	(1,347)
Accumulated other comprehensive loss:			
Balance beginning of year	(18,783)	(24,508)	(515)
Other comprehensive (loss) income, net of tax (see Note 15)	(381)	5,725	(23,993)

Balance end of year	(19,164)	(18,783)	(24,508)
Total stockholders' equity	$1,084,837	$1,050,536	$969,855

	Year Ended December 31, 2009	2008	2007
		(in thousands)	
Comprehensive income:			
Net income	$81,555	$105,210	$99,149
Other comprehensive (loss) income, net of tax (see Note 15)	(381)	5,725	(23,993)
Comprehensive income	81,174	110,935	75,156
Less: net income attributable to non-controlling interest	-	(130)	(377)
Consolidated comprehensive income	$81,174	$110,805	$74,779

Reconciliation of Shares for Year Ended December 31,

	2009 Shares	2008 Shares
Common stock:		
Balance beginning of year	38,676,054	37,842,221
Issuance of common stock:		
Stock options	78,022	83,334
Performance share plan	-	35,085
Restricted stock	80,118	89,042
Earn-out litigation	-	593,804
Equity offering	-	-
Dividend reinvestment and stock purchase plan	143,332	-
Other common stock	-	32,568
Balance end of year	38,977,526	38,676,054
Treasury stock:		
Balance beginning of year	40,183	45,916
Forfeitures of unvested restricted stock	6,088	15,107
Share withholding for payment of taxes associated with vesting of restricted shares and stock option exercise stock swaps	21,569	17,233
Equity compensation issuances and other	(59,006)	(38,073)
Balance end of year	8,834	40,183

The accompanying notes to consolidated financial statements are an integral part of these consolidated financial statements.

BLACK HILLS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2009, 2008 and 2007

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Corporation is a diversified energy company headquartered in Rapid City, South Dakota. We are a holding company that, through our subsidiaries, operates in two primary business groups: Utilities and Non-regulated Energy. The Utilities Group includes two financial reporting segments: regulated Electric Utilities and regulated Gas Utilities. Regulated Electric Utilities include the operating results of the regulated electric utility operations of Black Hills Power and Colorado Electric, and the regulated electric and natural gas utility operations of Cheyenne Light. Regulated Gas Utilities consist of the operating results of the regulated natural gas utility operations of Colorado Gas, Iowa Gas, Kansas Gas and Nebraska Gas all doing business as Black Hills Energy.

The Non-regulated Energy Group includes four financial reporting segments: Oil and Gas, Power Generation, Coal Mining and Energy Marketing. Oil and Gas, which is conducted through BHEP and its subsidiaries, engages in oil and natural gas exploration and production activities. Power Generation, which is conducted through Black Hills Electric Generation and its subsidiaries, engages in independent power generation activities. Coal Mining, which is conducted through WRDC, engages in coal mining activities. Energy Marketing, which is conducted through Enserco, engages in natural gas and crude oil marketing activities. All of these businesses are aggregated for reporting purposes as Non-Regulated Energy.

For further descriptions of our reportable business segments, see Note 17.

On July 14, 2008, we completed the acquisition of a regulated electric utility in Colorado and regulated gas utilities in Colorado, Iowa, Kansas and Nebraska from Aquila. Effective as of the acquisition date, the assets and liabilities, results of operations and cash flows of these acquired utilities are included in our Consolidated Financial Statements. See Note 23 for additional information.

On July 11, 2008, we completed the sale of seven IPP plants. For all periods presented, amounts associated with the divested IPP plants have been classified as discontinued operations on the accompanying Consolidated Financial Statements. See Note 22 for additional information.

Use of Estimates and Basis of Presentation

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The significant accounting policies that we believe include management estimates that are critical in understanding our financial results relate to market value of derivatives, intangible asset valuations and useful lives, long-lived asset values and useful lives, proved oil and gas reserve volumes, employee benefit plans, valuation of deferred taxes and contingencies. Actual results could differ materially from those estimates.

Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation. The consolidated statements of income for the prior periods have been modified to reflect the retrospective application of accounting requirements under ASC 810 for non-controlling interests. The consolidated statement of cash flows at December 31, 2008 and 2007 has been modified with Net cash provided by operating activities to reflect the amount of "Other non-cash adjustments" previously included within "Other operating activities" and to present "Regulatory assets" and "Regulatory liabilities" as separate components of the operating cash flows. The consolidated statement of cash flows at December 31, 2008 and 2007 has also been modified within the Net cash provided by financing activities to reflect separate presentation of cash flows from short-term borrowings and cash outflows from short-term borrowings. The increase (decrease) in short-term debt was previously combined. The statement of common stockholders' equity has been modified to provide more details of the transactions affecting the changes in the balances. The recurring fair value measures included in Note 4, Fair Value Measures, have been modified to present the cash collateral previously included in Level 1 derivative assets and liabilities in "Counterparty Netting and Cash Collateral." These reclassifications had no effect on total assets, net income, cash flows or earnings per share.

Principles of Consolidation

The consolidated financial statements include the accounts of Black Hills Corporation and its wholly-owned and majority-owned subsidiaries. Generally, we use the equity method of accounting for investments of which we own between 20% and 50% and investments in partnerships under 20% if we exercise significant influence. In May 2003, our subsidiary, Black Hills Wyoming, entered into an agreement with Wygen Funding, LP (a VIE), to lease the Wygen I plant. We were considered the primary beneficiary of the plant and therefore, consolidated Wygen Funding under ASC 805-10. In June 2008, we purchased the Wygen I plant. Since the plant was previously consolidated into our financial statements, the transaction had minimal impact on our Consolidated Financial Statements.

All intercompany balances and transactions have been eliminated in consolidation except for revenues and expenses associated with regulated intercompany fuel sales in accordance with accounting standards for rate regulated operations. Total intercompany fuel and energy sales not eliminated were $48.7 million, $47.5 million and $13.2 million in 2009, 2008 and 2007, respectively.

Our consolidated statements of income include operating activity of acquired companies beginning with their acquisition date.

We use the proportionate consolidation method to account for our working interests in oil and gas properties and for our ownership interest in the jointly owned Black Hills Power transmission tie, the Wyodak power plant, the Wygen I power plant, the Wygen III power plant under construction, and the BHEP gas processing plant. See Note 7 for additional information.

Cash Equivalents

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

Restricted Cash

The Black Hills Wyoming project financing completed in December 2009, requires that cash accounts are maintained for various specified purposes. We do not readily have access to these accounts and can only withdraw funds upon meeting certain requirements. Therefore, we have classified these amounts as restricted cash.

Allowance for Doubtful Accounts

We maintain an allowance for doubtful accounts which reflects our best estimate of potentially uncollectible trade receivables. We regularly review our trade receivable allowances by considering such factors as historical experience, credit worthiness, the age of the receivable balances and current economic conditions that may affect the ability to pay.

Following is a summary of receivables at December 31 (in thousands):

	2009	2008
Accounts receivable	$217,723	$291,151
Unbilled revenues	61,387	73,004
Total accounts receivable	279,110	364,155
Allowance for doubtful accounts	(4,621)	(6,751)
Net accounts receivable	$274,489	$357,404

Materials, Supplies and Fuel

As of December 31, the following amounts by major classification are included in Materials, supplies and fuel on the accompanying Consolidated Balance Sheets (in thousands):

	2009	2008
Materials and supplies	$31,535	$32,580
Fuel - Electric Utilities	7,128	10,058
Natural gas in storage - Gas Utilities	24,053	59,529
Gas and oil held by Energy Marketing*	60,606	15,854
Total materials, supplies and fuel	$123,322	$118,021

* As of December 31, 2009 and 2008, market adjustments related to Gas and oil held by Energy Marketing and recorded in inventory as part of a fair value hedge transaction, were $(0.3) million and $(9.4) million, respectively.

Natural gas in storage at our regulated Gas Utilities primarily represents gas purchased for use by our customers and is valued at the weighted-average cost of the gas. The value of our natural gas in storage fluctuates with the season volume requirements of our business and the commodity price of natural gas. There has been a notable overall price decrease from 2008 to 2009.

Gas and oil held by Energy Marketing primarily consists of gas held in storage and gas imbalances held on account with pipelines. Gas imbalances represent the differences that arise between volumes of gas received into the pipeline versus gas delivered off of the pipeline. Natural gas and oil inventory is stated at the lower of cost or market on a weighted-average cost basis. To the extent that gas and oil held by Energy Marketing has been designated as the underlying hedged item in a fair value hedge transaction, those volumes are stated at market value using published industry quotations. See Note 3 for further discussion of Energy Marketing trading activities.

Property, Plant and Equipment

Additions to property, plant and equipment are recorded at cost. Included in the cost of regulated construction projects is AFUDC, which represents the approximate composite cost of borrowed funds and a return on equity used to finance a project. In addition, we also capitalize interest, when applicable, on undeveloped leasehold costs and certain non-regulated construction projects. The amount of AFUDC and interest capitalized was $12.1 million, $8.0 million and $14.8 million in 2009, 2008 and 2007, respectively. The cost of regulated utility property, plant and equipment retired, or otherwise disposed of in the ordinary course of business, less salvage, is charged to accumulated depreciation. Removal costs associated with non-legal obligations related to our regulated properties are reclassified from accumulated depreciation and reflected as regulatory liabilities. Retirement or disposal of all other assets, except for oil and gas properties as described below, results in gains or losses recognized as a component of operating income. Ordinary repairs and maintenance of property are charged to operations as incurred.

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

Oil and Gas Operations

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

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

Under the full cost method, net capitalized costs are subject to a ceiling test which limits these costs to the present value of future net cash flows discounted at 10%, net of related tax effects, plus the lower of cost or fair value of unproved properties included in the net capitalized costs. Future net cash flows are estimated based on SEC-defined end-of-period commodity prices adjusted for contracted price changes. Effective for the 2009 fiscal year end, a twelve month average price is calculated using the price at the first day of each month for each of the preceding twelve months. If the net capitalized costs exceed the full cost "ceiling" at period end, a permanent non-cash write-down would be charged to earnings in that period.

As a result of lower natural gas prices at March 31, 2009, we recorded a non-cash ceiling test impairment of oil and gas long-lived assets included in the Oil and Gas segment. The lower prices at March 31, 2009 resulted in a $43.3 million pre-tax decrease in the full cost accounting method's ceiling limit for capitalized oil and gas property costs. The write-down in the net carrying value of our natural gas and crude oil properties was recorded as Impairment of long-lived assets and was based on the March 31, 2009 NYMEX price of $3.63 per Mcf, adjusted to $2.23 per Mcf at the wellhead, for natural gas; and NYMEX price of $49.66 per barrel, adjusted to $45.32 per barrel at the wellhead, for crude oil.

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Also at December 31, 2008, as a result of low crude oil and natural gas prices we recorded a pre-tax non-cash ceiling test impairment of our oil and gas long-lived assets totaling $91.8 million. The write-down of gas and oil properties was based on December 31, 2008 NYMEX spot prices of $5.71 per Mcf, adjusted to $4.44 per Mcf at the wellhead, for natural gas; and $44.60 per barrel, adjusted to $32.74 per barrel at the wellhead, for crude oil. No ceiling test write-downs were recorded during 2007.

Impairment of Long-lived Assets

For our long-lived assets, other than assets of our oil and gas activities described above, we periodically evaluate whether events and circumstances have occurred which may affect the estimated useful life or the recoverability of the remaining asset balance. If such events or circumstances were to indicate that the carrying amount of these assets was not recoverable, we would estimate the future cash flows expected to result from the use of the assets and their eventual disposition. If the sum of the expected future cash flows (undiscounted and without interest charges) was less than the carrying amount of the long-lived assets, we would recognize an impairment loss. In 2007, we recorded a $2.7 million pre-tax impairment charge to reduce the carrying value of the Ontario power plant and related intangibles and a $0.6 million pre-tax impairment charge of goodwill related to lower partnership earnings as a result of a partnership impairment charge for the Glenns Ferry and Rupert power plants, in which we hold a 50% interest and account for under the equity method (see Note 12).

Goodwill and Intangible Assets

Under accounting standards for goodwill and intangible assets, goodwill and intangible assets with indefinite lives are not amortized but the carrying values are reviewed annually for impairment. Intangible assets with a finite life continue to be amortized over their estimated useful lives. We perform this annual review of goodwill and intangible assets during the fourth quarter of each year (or more frequently if impairment indicators arise).

The substantial majority of our goodwill and intangible assets are contained within the Utilities Group relating to the 2008 purchase of utility properties in the Aquila Transaction. Changes to goodwill and intangible assets during the years ended December 31, 2009 and 2008 are as follows (in thousands):

	Goodwill	Amortized Other Intangible Assets
Balance at December 31, 2007, net of accumulated amortization	$11,482	$3
Additions	347,808	4,919
Amortization expense	-	(38)
Balance at December 31, 2008, net of accumulated amortization	359,290	4,884
Adjustments	(5,556)	(365)
Amortization expense	-	(210)
Balance at December 31, 2009, net of accumulated amortization	$353,734	$4,309

On July 14, 2008, we completed the acquisition of one regulated electric and four regulated gas utilities from Aquila. As of December 31, 2008, $344.5 million was recorded to goodwill for this transaction. Goodwill was adjusted for final working capital and tax adjustments during 2009 of $5.6 million. Final allocation of the purchase price included $339.0 million of goodwill and $4.9 million of intangible assets (see Note 23). Less than $0.1 million of the intangible assets have an indefinite life while the remaining amount of $4.8 million is being amortized over twenty years.

During 2008, we adjusted goodwill $3.3 million for issuance of shares of common stock related to the settlement of the Earn-out Litigation with former Indeck shareholders. This resulted from the settlement of two proceedings brought by former stockholders of Indeck, a company we acquired in 2000. In the first settlement agreement, we agreed to pay additional earn-out consideration to the former Indeck stockholders. The aggregate value of the 451,465 shares of additional Black Hills common stock issued was recorded as additional goodwill. The second proceeding was an arbitration proceeding which settled on September 19, 2008. The arbitrator instructed us to pay $4.0 million in earn-out consideration and on December 19, 2008, we issued 142,339 shares of additional common stock to former Indeck stockholders. In accordance with accounting standards for discontinued operations, the goodwill held at the IPP plants was allocated while recording the IPP Transaction.

We performed our annual goodwill impairment tests during the fourth quarter. We estimated the fair value of the goodwill using discounted cash flow methodology and an analysis of comparable transactions. These analyses required the input of several critical assumptions, including future growth rates, cash flow projections, operating cost escalation rates, rates of return, a risk-adjusted discount rate, timing and level of success in regulatory rate proceedings, the cost of debt and equity capital, and long-term earnings and merger multiples for comparable companies. We believe that the goodwill amount reflects the value of the relatively stable, long-lived cash flows of the regulated gas utility business, considering the regulatory environment and market growth potential and the value of the significant rate base growth opportunities at our electric utility in Colorado.

Intangible assets represent easements, right-of-way and trademarks and are amortized using a straight-line method using estimated useful lives of 20 years. Intangible assets totaled $4.3 million at December 31, 2009 with amortization expense for intangible assets was $0.2 million, less than $0.1 million and $0.1 million in each of the years 2009, 2008 and 2007, respectively. Amortization expense for existing intangible assets is expected to be $0.2 million per year through 2014.

Asset Retirement Obligations

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

Derivatives and Hedging Activities

The accounting standards for derivatives and hedging require that derivative instruments be recorded on the balance sheet as either an asset or liability measured at its fair value and that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

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

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Weather Hedges

As approved in the State of Iowa, Iowa Gas uses a weather derivative to mitigate the effect of fluctuations from normal weather, but not for trading or speculative purposes. Accounting standards for derivatives and hedging require that weather hedges are accounted for by the intrinsic value method which records an asset or liability for the difference between the actual and contracted threshold cooling or heating degree days in the period, multiplied by the contract price. Any gains or losses recorded on these contracts are recorded as regulatory assets or regulatory liabilities, respectively. Anticipated settlements totaling $1.8 million are included in Accounts receivable on the accompanying Consolidated Balance Sheets as of December 31, 2009. Anticipated settlements totaling $1.8 million are included in Other current liabilities on the accompanying Consolidated Balance Sheets as of December 31, 2008.

Currency Adjustments

Our functional currency for all operations is the United States dollar. Through Enserco, we engage in natural gas marketing transactions in Canada and accordingly, have various transactions that have been denominated in Canadian dollars. These Canadian denominated transactions/balances are adjusted to United States dollars for financial reporting purposes using the year-end exchange rate for balance sheet items and an average exchange rate during the period for income statement items. Gains or losses on currency transactions executed in Canadian dollars are recorded in Operating revenues on the accompanying Consolidated Statements of Income as incurred.

Deferred Financing Costs

Deferred financing costs are amortized using the effective interest method over the term of the related debt.

Development Costs

Commencing in 2009 with the adoption of revised accounting standards for business combinations, we expense, when incurred, development and acquisition costs associated with corporate development activities prior to acquiring or beginning construction of a project. Expensed development costs are included in Administrative and general operating expenses on the accompanying Consolidated Statement of Income.

Legal Costs

Litigation liabilities, including potential settlements are recorded when it is probable we are likely to incur liability or settlement costs, and those costs can be reasonably estimated. Litigation settlement accruals are recorded net of probable insurance recoveries. Legal costs related to ongoing litigation are expensed as incurred.

Non-controlling Interest

Under accounting standards for variable interest entities, we were considered the primary beneficiary of the agreement with Wygen Funding, LP to lease the Wygen I plant. Non-controlling interest in the accompanying Consolidated Statements of Income represents the non-affiliated equity investors' interest in Wygen Funding, L.P., a VIE. In June 2008, at the end of the lease term, we purchased the Wygen I plant.

Earnings attributable to minority ownership are shown on the accompanying Consolidated Statements of Income on a pre-tax basis as the entity with the non-controlling investor is a limited partnership which pays no tax at the corporate level.

AFUDC

AFUDC represents the approximate composite cost of borrowed funds and a return on equity used to finance a utility project. AFUDC for the years ended December 31, 2009, 2008 and 2007 was $11.7 million, $6.6 million and $11.2 million, respectively. The equity component of AFUDC for 2009, 2008 and 2007 was $5.9 million, $3.8 million and $4.8 million, respectively. The borrowed funds component of AFUDC for 2009, 2008 and 2007 was $5.8 million, $2.8 million and $6.4 million, respectively. The equity component of AFUDC is included in Other income (expense), and the borrowed funds component of AFUDC is an offset to Interest expense on the accompanying Consolidated Statements of Income.

Regulatory Accounting

Our Utilities Group is subject to regulation by various state and federal agencies. The accounting policies followed are generally subject to the Uniform System of Accounts of FERC. These accounting policies differ in some respects from those used by our non-regulated businesses.

Our financial statements follow accounting standards for regulated operations and reflect the effects of the different ratemaking principles followed by the various jurisdictions regulating the utilities. If rate recovery becomes unlikely or uncertain due to competition or regulatory action, these accounting standards may no longer apply. As of December 31, 2009 and 2008, we had $111.1 million and $135.4 million in net regulatory assets for which we will recover the cost, but are not allowed a return. In the event we determine that Black Hills Power, Cheyenne Light, Iowa Gas, Nebraska Gas, Kansas Gas, Colorado Gas or Colorado Electric no longer meet the criteria for following accounting standards for regulated operations, the accounting impact to the Company could be an extraordinary non-cash charge to operations, which could be material.

On December 31, 2009 and 2008, we had the following regulatory assets and liabilities (in thousands):

	2009	2008
Regulatory assets		
Deferred energy and fuel costs adjustments	$30,590	$32,198
Deferred gas cost adjustments and gas price derivatives	11,496	25,364
AFUDC	13,935	8,719
Employee benefit plans	86,818	98,414
Environmental	2,268	2,406
Asset retirement obligations	2,912	2,598
Bond issue cost	3,990	4,121
Other regulatory assets	8,654	5,275
	$160,663	$179,095
Regulatory liabilities		
Deferred energy and gas costs	$1,932	$2,417
Employee benefit plans	-	1,513
Cost of removal	35,983	31,351
Revenue subject to refund	3,938	2,786
Other regulatory liabilities	7,697	5,592
	$49,550	$43,659

Regulatory assets are primarily recorded for the probable future revenue to recover the costs associated with regulated utilities' defined benefit postretirement plans, future income taxes related to the deferred tax liability for the equity component of allowance for funds used during construction of utility assets and unrecovered energy and fuel costs.

Deferred Energy and Fuel Cost Adjustments – deferred energy and fuel cost adjustments represent the cost of electricity delivered to our electric utility customers in excess of current rates and which will be recovered in future rates. Deferred energy and fuel cost adjustments are recorded and recovered or amortized as approved by the appropriate state commission. As of December 31, 2009 and 2008, respectively, $27.9 million and $29.4 million was considered current and $2.6 million and $2.8 million, respectively, is classified as non-current as it is expected to be recovered through the first quarter of the following year.

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

AFUDC - The equity component of AFUDC is considered a permanent difference for tax purposes with the tax benefit being flowed through to customers as prescribed or allowed by regulators. If, based on a regulator's action, it is probable the utility will recover the future increase in taxes payable represented by this flow-through treatment through a rate revenue increase, a regulatory asset is recognized. This regulatory asset itself is a temporary difference for which a deferred tax liability must be recognized. Accounting standards for income taxes specifically address AFUDC-equity, and require a gross-up of such amounts to reflect the revenue requirement associated with a rate-regulated environment. Recovery of this asset is up to 45 years.

Employee Benefit Plans - Employee benefit plans include the unrecognized prior service costs and net actuarial loss associated with our defined benefit pension plans and post-retirement benefit plans in regulatory assets rather than in accumulated other comprehensive income. The recovery period is up to 13 years.

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

Asset Retirement Obligations - AROs represent the estimated recoverable costs for legal obligations associated with the retirement of a tangible long-lived asset. See Note 10 for additional details. The recovery period is up to 44 years.

Bond Issue Costs – Bond issue costs are recovered over the remaining life of the original issue or, if refinanced, over the life of the new issue, which as of December 31, 2009 will be amortized through November 2037.

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

Deferred Energy and Gas Costs - Deferred energy costs related to over-recovery in purchased power, transmission and natural gas costs charged to Cheyenne Light customers through a PCA and GCA mechanism. Settlement is expected within one year.

Employee Benefit Plans – Employee benefit plans represents the cumulative excess of pension costs recovered in rates over pension expense recorded in accordance with accounting standards for compensation - retirements.

Cost of Removal - Cost of removal for utility plant represents the estimated cumulative net provisions for future removal costs included in depreciation expense for which there is no legal obligation for removal. Liabilities will be settled and trued up following completion of the related activities of up to 44 years.

Revenues Subject To Refund - Revenues subject to refund represent a portion of the revenues collected from customers based on approved interim rates which are contingent on the outcome of final rate orders. Settlement is expected within one year.

Income Taxes

The Company and its subsidiaries file consolidated federal income tax returns. Income taxes for consolidated subsidiaries are allocated to the subsidiaries based on separate company computations of taxable income or loss.

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

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

Revenue Recognition

Revenue is recognized when there is persuasive evidence of an arrangement with a fixed or determinable price, delivery has occurred or services have been rendered, and collectibility is reasonably assured.

Utility revenues are based on authorized rates approved by the state regulatory agencies and FERC. Revenues related to the sale, transmission and distribution of energy delivery service are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based on systematic meter readings throughout a month. Meters that are not read during a given month are estimated and trued-up to actual use in a future period. At the end of each month, amounts of energy delivered to customers since the date of their last meter reading are estimated and the corresponding unbilled revenue is recorded. The amount of unbilled revenues recorded in Accounts receivable on the Consolidated Balance Sheets as of December 31, 2009 and 2008 was $61.4 million and $73.0 million, respectively.

In addition, in accordance with accounting standards for derivatives and hedging, certain energy marketing activities are recorded at fair value as of the balance sheet date and net gains or losses resulting from the revaluation of these contracts to fair value are recognized currently in the results of operations. All energy marketing contracts that do not meet the definition of a derivative have been accounted for under the accrual method of accounting.

We present our operating revenues from energy marketing operations in accordance with the accounting standards for energy trading contracts. Accordingly, gains and losses (realized and unrealized) on transactions at our natural gas and crude oil marketing operations are presented on a net basis in operating revenues, whether or not settled physically.

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

For our Investment in Associated Companies, which are involved in power generation, we use the equity method to recognize our pro rata share of the net income or loss of the associated company. As of December 31, 2009 and 2008, we held $1.6 million and $2.6 million in investments which is included in Investments on the accompanying Consolidated Balance Sheets.

Earnings per Share of Common Stock

Basic earnings per share from continuing operations is computed by dividing "Income from continuing operations" less preferred stock dividends, by the weighted average number of common shares outstanding during each year. Diluted earnings per share gives effect to all dilutive potential common shares outstanding during a period. A reconciliation of income from continuing operations and basic and diluted share amounts is as follows (in thousands):

	2009		2008		2007	
	Income	Average Shares	(Loss)	Average Shares	Income	Average Shares
Basic - Income (loss) from continuing operations	$78,756	38,614	$(52,037)	38,193	$75,658	37,024
Dilutive effect of:						
Stock options	-	-	-	-	-	111
Contingent shares issuable for prior acquisition	-	-	-	-	-	159
Restricted stock	-	66	-	-	-	81
Other dilutive effects	-	4	-	-	-	39
Diluted - Income (loss) from continuing operations	$78,756	38,684	$(52,037)	38,193	$75,658	37,414

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

	2009	2008	2007
Options to purchase common stock	462	-	34

(2) RECENTLY ADOPTED AND RECENTLY ISSUED ACCOUNTING STANDARDS

Recently Adopted Accounting Standards

FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles, ASC 105

On July 1, 2009, the FASB Accounting Standards CodificationTM (the Codification) became the source of authoritative GAAP recognized by the FASB to be applied by non-governmental entities. On the effective date of this Statement, the Codification superseded all then-existing non-SEC accounting and reporting standards. All other non-SEC accounting literature not included or grandfathered in the Codification became non-authoritative. This Statement is effective for financial statements issued for interim and annual periods ending after September 15, 2009.

Following this Statement, the FASB will not issue new standards in the form of Statements, FASB Staff Positions, or Emerging Issues Task Force Abstracts. Instead, it will issue Accounting Standards Updates. The FASB will not consider Accounting Standards Updates as authoritative in their own right. Accounting Standards Updates will serve only to update the Codification, provide background information about the guidance, and provide the basis for conclusions on the change(s) in the Codification.

Earnings Per Share, ASC 260

The ASC for Earnings per Share states that unvested share-based payment awards that contain non-forfeitable rights to dividends are "participating securities" as defined and should be included in computing EPS using the two-class method. The two-class method is an earnings allocation method for computing EPS and determines EPS based on dividends declared on common stock and participating securities in any undistributed earnings. As of January 1, 2009, we prepared our current and prior period EPS computation in accordance with these accounting standards and there was no impact on our EPS.

Business Combinations, ASC 805

The ASC for Business Combinations requires that the acquisition method of accounting be used for all business combinations and for an acquirer to be identified for each business combination. It also establishes principles and requirements for how the acquirer (i) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any non-controlling interest in the acquiree, (ii) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase and (iii) discloses the nature and financial effects of the business combination; and requires restructuring and acquisition-related costs to be expensed. In addition, if income tax liabilities are settled for an amount other than as previously recorded, such adjustments could affect income tax expense in the period of adjustment. Effective January 1, 2009, any impact the standard will have on our consolidated financial statements will depend on the nature and magnitude of any future acquisitions we consummate including any tax-related adjustments.

Derivatives and Hedging, ASC 815

Accounting standards for Derivatives and Hedging require enhanced disclosures about derivatives and hedging activities and their affect on an entity's financial position, financial performance and cash flows. Accounting standards for derivatives and hedging encourages, but does not require, disclosures for earlier periods presented for comparative purposes at initial adoption. Required disclosures for periods subsequent to January 1, 2009 are provided in Note 3 and Note 4.

Fair Value Measurements and Disclosures, ASC 820

The ASC for Fair Value Measurements and Disclosures defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosure requirements related to fair value measurements. This does not expand the application of fair value accounting to any new circumstances, but applies the framework to other applicable GAAP that requires or permits fair value measurement. We apply fair value measurements to certain assets and liabilities, primarily commodity derivatives within our Energy Marketing and Oil and Gas segments, interest rate swap instruments, and other miscellaneous financial instruments.

On January 1, 2008, we discontinued our use of a "liquidity reserve" in valuing the total forward positions within our energy marketing portfolio. This impact was accounted for prospectively as a change in accounting estimate and resulted in a $1.2 million after-tax benefit that was recorded within our unrealized marketing margins. Unrealized margins are presented as a component of Operating revenues on the accompanying Consolidated Statements of Income. Disclosures regarding the level of pricing observability associated with instruments carried at fair value are provided in Note 4.

Financial Instruments, ASC 825

The ASC for Financial Instruments requires public companies to provide more frequent disclosures about the fair value of their financial instruments for interim and annual periods ending after June 15, 2009. These disclosures are included in Note 5.

Subsequent Events, ASC 855

The ASC for Subsequent Events establishes general standards of accounting for and disclosures of events that occur after the balance sheet date, but before financial statements are issued or are available to be issued. These standards and disclosures were applied to our financial statements issued after June 15, 2009.

Consolidation of Non-Controlling Interest, ASC 810

The ASC for Consolidation of Non-Controlling Interest establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the non-controlling interest, changes in a parent's ownership interest, and the valuation of retained non-controlling equity investments when a subsidiary is deconsolidated. The ASC establishes disclosure requirements that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. These standards and disclosure requirements were effective January 1, 2009.

Non-controlling interest in the accompanying Consolidated Statements of Income represents a non-affiliated equity investors' interest in Wygen Funding LP, a Variable Interest Entity. In June 2008, we purchased the non-controlling share retiring $128.3 million of Wygen I project debt. Presentation of a non-controlling interest that we held until June 2008 was retrospectively applied as required, and had an immaterial overall effect on our consolidated financial position, results of operations and cash flows.

Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans, ASC 715

The ASC 715 for Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans requires the recognition of the overfunded or underfunded status of defined benefit postretirement plans as an asset or liability in the statement of financial position, recognition of changes in the funded status in comprehensive income, measurement of the funded status of a plan as of the date of the year-end statement of financial position and provides for related disclosures. Effective for fiscal years ending after December 15, 2008, this accounting standard required the measurement of the funded status of the plan to coincide with the date of the year-end statement of financial position. Therefore, the measurement date for the funded status of our pension and other postretirement benefit plans was changed to December 31 from September 30. ASC 715 also provides guidance on an employer's disclosure about plan assets for a defined benefit pension or other postretirement plans. These disclosures are effective for fiscal years ending after December 15, 2009. See Note 18 for additional information.

Extractive Activities - Oil and Gas Reserves (SEC Release #33-8995), ASC 932-10-S99

The FASB issued an accounting standards update which aligns the oil and gas reserve estimation and disclosure requirements with the SEC released Final Rule, "Modernization of Oil and Gas Reporting" amending the existing Regulation S-K and Regulation S-X reporting requirements to align with current industry practices and technology advances. Key revisions include the ability to include non-traditional resources in reserves, the use of new technology for determining reserves, permitting disclosure of probable and possible reserves, and changes to the pricing used to determine reserves from the year-end price to a 12-month average price. The average is calculated using the first-day-of-the-month price for each of the 12 months that make up the reporting period. The amendment is effective for annual reporting periods ending on or after December 31, 2009. The implementation of this SEC requirement resulted in additional depletion expense of $1.3 million in 2009.

Recently Issued Accounting Pronouncements

Consolidation of Variable Interest Entities, ASC 810-10-15

In June 2009, the FASB issued a revision regarding consolidations. The revised accounting guidance requires a company to consider whether an entity that is insufficiently capitalized or is not controlled through voting should be consolidated. It will require additional disclosures about the involvement with variable interest entities and any significant changes in risk exposure due to that involvement. This standard is effective for annual periods that begin after November 15, 2009. We are currently assessing the impact that the adoption of this standard will have on our financial condition, results of operations, and cash flows.

Fair Value Measurements, ASC 820

In January 2010, the FASB issued guidance related to improving disclosures about fair value measurements. The guidance requires separate disclosures of the amounts of transfers in and out of Level 1 and Level 2 fair value measurements and a description of the reason for such transfers. In the reconciliation for Level 3, fair value measurements using significant unobservable inputs, information about purchases, sales, issuances and settlements shall be presented separately. These disclosures are required for interim and annual reporting periods and were effective for the Company on January 1, 2010, except for the disclosures related to the purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which are effective on January 1, 2011. The guidance will require additional disclosures, but will not impact our financial position or results of operations.

(3) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and non-regulated energy sectors expose the Company to a number of risks in the normal operations of its businesses. Depending on the activity, we are exposed to varying degrees of market risk and counterparty risk. We have developed policies, processes, systems, and controls to manage and mitigate these risks.

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

- Commodity price risk associated with our marketing businesses, our natural long position with crude oil and natural gas reserves and production, fuel procurement for certain of our gas-fired generation assets and variability in revenue due to changes in gas usage at our regulated Gas Utilities segment resulting from commodity price changes;

- Interest rate risk associated with variable rate credit facilities and project financing floating rate debt as described in Notes 8 and 9; and

- Foreign currency exchange risk associated with natural gas marketing business transacted in Canadian dollars.

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

Trading Activities

Natural Gas and Crude Oil Marketing

We have a natural gas and crude oil marketing business specializing in producer services, end-use origination and wholesale marketing that conducts business in the United States and Canada.

Contracts and other activities at our natural gas and crude oil marketing operations are accounted for under the accounting standards for derivatives and hedging and energy trading contracts. As such, all of the contracts and other activities at our natural gas and crude oil marketing operations that meet the definition of a derivative are accounted for at fair value. The fair values are recorded as either Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets. The net gains or losses are recorded as Operating revenues in the accompanying Consolidated Statements of Income. ASC 940-325-S99 precludes mark-to-market accounting for energy trading contracts that are not defined as derivatives. As part of our natural gas and crude oil marketing operations, we often employ strategies that include derivative contracts along with inventory, storage and transportation positions to accomplish the objectives of our producer services, end-use origination and wholesale marketing groups. Except in limited circumstances when we are able to designate transportation, storage or inventory positions as part of a fair value hedge, accounting standards for derivatives and hedging generally do not allow us to mark inventory, transportation or storage positions to market. The result is that while a significant majority of our natural gas and crude oil marketing positions are economically hedged, we are required to mark a portion of our overall strategies (the derivatives) to market value, but are generally precluded from marking the rest of our economic hedges (transportation, inventory or storage) to market. Volatility in reported earnings and derivative positions results from these accounting requirements.

To effectively manage our portfolios, we enter into forward physical commodity contracts, financial derivative instruments including over-the-counter swaps and options and storage and transportation agreements. The business activities of our Energy Marketing segment are conducted within the parameters as defined and allowed in the BHCRPP and further delineated in the energy marketing Risk Management Policies and Procedures as approved by our Executive Risk Committee. Our contracts do not include credit risk-related contingent features.

We use a number of quantitative tools to measure, monitor and limit our exposure to market risk in our natural gas and oil marketing portfolio. We limit and monitor our market risk through established limits on the nominal size of positions based on type of trade, location and duration. Such limits include those on fixed price, basis, storage, transportation and foreign exchange positions.

Daily risk management activities include reviewing positions in relation to established position limits, assessing changes in daily mark-to-market and other non-statistical risk management techniques.

The contract or notional amounts and terms of the natural gas and crude oil marketing and derivative commodity instruments at December 31, are set forth below:

	2009		2008	
	Notional Amounts	Latest expiration (months)	Notional Amounts	Latest expiration (months)
(thousands of MMBtu)				
Natural gas basis swaps purchased	231,703	22	187,368	34
Natural gas basis swaps sold	232,673	22	186,710	34
Natural gas fixed-for-float swaps purchased	60,927	16	85,412	24
Natural gas fixed-for-float swaps sold	72,904	25	90,171	24
Natural gas physical purchases	120,680	27	131,937	16
Natural gas physical sales	124,830	27	145,706	21
Natural gas options purchased	-	-	1,440	3
Natural gas options sold	-	-	1,440	3
(thousands of Bbls of oil)				
Crude oil physical purchases	5,048	12	7,446	12
Crude oil physical sales	4,998	12	6,251	12
Crude oil swaps purchased	-	-	435	24
Crude oil swaps sold	69	2	502	24

Derivatives and certain natural gas and oil marketing activities were marked to fair value on December 31, 2009 and 2008, and the associated gains and/or losses recognized in earnings. The amounts related to the accompanying Consolidated Balance Sheets and Consolidated Statements of Income as of December 31, 2009 and 2008 are as follows (in thousands):

	December 31, 2009	December 31, 2008
Current assets	$25,366	$52,723
Non-current assets	3,090	(145)
Current liabilities	9,377	15,553
Non-current liabilities	(733)	(777)
Cash collateral receivable/(payable) included in derivative assets/liabilities(a)	2,728	(16,315)
Unrealized gain	17,084	54,117

(a) A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim, or the obligation to return, cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty. At December 31, 2009, we had the right to reclaim cash collateral of $2.7 million and at December 31, 2008, we had an obligation to return cash collateral of $16.3 million.

In addition, certain volumes of natural gas inventory have been designated as the underlying hedged item in a fair value hedge transaction. These volumes include market adjustments based on published industry quotations. Market adjustments are recorded in inventory on the Consolidated Balance Sheets and the related unrealized gain/loss on the Consolidated Statements of Income effectively offsetting the earnings impact of the unrealized gain/loss recognized on the associated derivative asset or liability described above. As of December 31, 2009 and 2008, the market adjustments recorded in inventory were $(0.3) million and $(9.4) million, respectively.

Activities Other than Trading

Oil and Gas Exploration and Production

We produce natural gas and crude oil through our exploration and production activities. Our natural "long" positions, or unhedged open positions, introduce commodity price risk and variability in our cash flows. We employ risk management methods to mitigate this commodity price risk and preserve cash flows and we have adopted guidelines covering hedging for our natural gas and crude oil production. These guidelines have been approved by our Executive Risk Committee, and are reviewed by our Board of Directors.

Over-the-counter swaps and options are used to mitigate commodity price risk and preserve cash flows. These derivative instruments fall under the purview of accounting standards for derivatives and hedges and we generally elect to utilize hedge accounting as allowed under this Statement.

At December 31, 2009 and 2008, we had a portfolio of swaps and options to hedge portions of our crude oil and natural gas production. We elect hedge accounting on those over-the-counter swaps and options. These transactions were designated at inception as cash flow hedges, properly documented and initially met prospective effectiveness testing. Effectiveness of our hedging position is evaluated at least quarterly.

At December 31, 2009 and 2008, the derivatives were marked to fair value and were recorded as Derivative assets or Derivative liabilities on the Consolidated Balance Sheets. The effective portion of the gain or loss on these derivatives was reported in other comprehensive income (loss) and the ineffective portion was reported in earnings.

On December 31, 2009 and 2008, we had the following swaps, options and related balances (dollars in thousands):

	December 31, 2009		December 31, 2008	
	Crude oil swaps/options	Natural gas swaps	Crude oil swaps/options	Natural gas swaps
Notional*	472,500	9,602,300	435,000	8,523,500
Maximum duration in years**	0.25	0.75	0.25	1.00
Current assets	$3,345	$5,994	$7,674	$11,828
Non-current assets	$136	$551	$3,464	$3,749
Current liabilities	$1,220	$1,435	$-	$-
Non-current liabilities	$2,502	$391	$10	$297
Pre-tax accumulated other comprehensive income (loss)	$(862)	$4,719	$9,642	$15,280
Earnings	$621	$-	$1,486	$-

* Crude in Bbls, gas in MMBtu.

** Refers to the term of the derivative instrument. Assets and liabilities are classified as current/non-current based on the timing of the hedged transaction and the corresponding settlement of the derivative instrument.

Most of our crude oil and natural gas hedges are deemed highly effective, resulting in limited earnings impact prior to realization. We estimate that a portion of the unrealized earnings currently recorded in accumulated other comprehensive loss will be realized in earnings during 2010. Based on December 31, 2009 market prices, a $4.7 million gain would be realized and reported in earnings during 2010. Estimated and actual realized gains will likely change during 2010 as market prices fluctuate.

Gas Utilities

Our regulated Gas Utilities segment purchases natural gas and distributes it in four states. During the winter heating season, our gas customers are exposed to potential price volatility; therefore, as allowed or required by state utility commissions, we have entered into certain exchange-traded natural gas futures, options and basis swaps to reduce our customers' underlying exposure to these fluctuations. These transactions are considered derivatives in accordance with accounting standards for derivatives and hedging and mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets. Gains and losses, as well as option premiums, on these transactions are recorded as Regulatory assets or Regulatory liabilities in accordance with accounting standards for regulated operations. Accordingly, the earnings impact is recognized in the Consolidated Statements of Income as a component of PGA costs when the related costs are recovered through our rates as part of PGA costs in operating revenue.

On December 31, 2009 and 2008, the contract or notional amounts and terms of the natural gas derivative commodity instruments held by our regulated Gas Utilities are as follows:

	2009		2008	
	Notional*	Latest Expiration (months)	Notional*	Latest Expiration (months)
Natural gas futures purchased	6,220,000	15	1,290,000	3
Natural gas options purchased	1,910,000	3	3,990,000	3
Natural gas options sold	-	-	820,000	3
Natural gas basis swaps purchased	225,000	3	-	-

* Gas in MMBtu

On December 31, 2009 and 2008, our Gas Utilities held the following derivative-related balances (in thousands):

	December 31, 2009	December 31, 2008
Current derivative assets(a)	$3,042	$4,224
Non-current derivative assets	$-	$-
Current derivative liabilities	$-	$2,924
Non-current derivative liabilities	$764	$-
Regulatory assets	$2,578	$11,668
Cash collateral included in derivative assets/liabilities(b)	$3,789	$8,744

(a) Includes option premium of $1.1 million and $4.2 million at December 31, 2009 and 2008, respectively, which will be recorded as a regulatory asset upon settlement of the options.

(b) A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim or the obligation to return cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement. At December 31, 2009 and 2008 we had the right to reclaim cash collateral of $3.8 million and $8.7 million, respectively.

Electric Utilities

At our regulated Electric Utilities, we occasionally hold natural gas in storage for use as fuel for generating electricity with our gas-fired combustion turbines. To minimize associated price risk and seasonal storage level requirements, we occasionally utilize various derivative instruments. These transactions are marked-to-market, designated as cash flow hedges, and recorded in Derivative liabilities, current and Accumulated other comprehensive income on the accompanying Consolidated Balance Sheets. Gains or losses on these transactions will be recorded in gross margins upon settlement.

On December 31, 2009, we had the following swaps and related balances (dollars, in thousands):

Notional*	232,500
Maximum terms in months	10
Current derivative liability	$ 5
Pre-tax accumulated other comprehensive income (loss)	$ (5)

* Gas in MMBtu

Based on December 31, 2009 market prices, a loss of less than $0.1 million will be realized in earnings during 2010. Estimated and actual realized losses will likely change during 2010 as market prices fluctuate.

Financing Activities

We engage in activities to manage risks associated with changes in interest rates. We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations.

- At December 31, 2009, we have $150.0 million of notional amount floating-to-fixed interest rate swaps designated as cash flow hedges in accordance with accounting guidance for derivatives and hedging and accordingly, the mark-to-market adjustments are recorded in Accumulated other comprehensive loss on the Consolidated Balance Sheets. The swaps have a maximum term of seven years.

- We also have interest rate swaps with a notional amount of $250.0 million which were entered into for the purpose of hedging interest rate movements that would impact long-term financings that were originally expected to occur in 2008. The swaps were originally designated as cash flow hedges in accordance with accounting guidance for derivatives and the mark-to-market values were recorded in Accumulated other comprehensive loss on the Consolidated Balance Sheets. Based on credit market conditions that transpired during the fourth quarter of 2008, we determined it was probable that the forecasted long-term debt financings would not occur in the time period originally specified and as a result, the swaps were no longer effective hedges and the hedge relationships were de-designated. Mark-to-market adjustments on the swaps are now recorded within the income statement and during 2009 we recorded a $55.7 million pre-tax unrealized mark-to-market gain, while in 2008 we recorded a $94.4 million pre-tax unrealized mark-to-market loss. These swaps are nine and nineteen year swaps which 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 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 stated termination dates.

On December 31, 2009 and 2008, our interest rate swaps and related balances were as follows (dollars in thousands):

	December 31, 2009		December 31, 2008	
	Interest Rate Swaps	Dedesignated Interest Rate Swaps	Interest Rate Swaps	Dedesignated Interest Rate Swaps
Notional	$150,000	$ 250,000	$150,000	$ 250,000
Weighted average fixed interest rate	5.04 %	5.67 %	5.04 %	5.67 %
Maximum terms in years	7.0	1.0 (a)	8.0	1.0
Current derivative assets	$-	$ -	$-	$ -
Non-current derivative assets	$-	$ -	$-	$ -
Current derivative liabilities	$6,342	$ 38,787	$5,740	$ 94,440
Non-current derivative liabilities	$9,075	$ -	$22,495	$ -
Pre-tax accumulated other comprehensive (loss)	$(15,417)	$ -	$(28,235)	$ -
Pre-tax gain (loss)	$-	$ 55,653	$-	$ (94,440)

(a) Reflects the amended mandatory early termination dates of the nine and nineteen year swaps. If the mandatory early termination dates are not extended, the swaps will require cash settlement based on the swap value on the termination date.

Based on December 31, 2009 market interest rates and balances, a loss of approximately $6.3 million would be realized and reported in pre-tax earnings during the next twelve months associated with our interest rate swaps that have been designated as hedges. Estimated and realized losses will change during the next twelve months as market interest rates fluctuate.

Foreign Exchange Contracts

Our Energy Marketing Segment conducts its gas marketing in the United States and Canada. Transactions in Canada are generally transacted in Canadian dollars and create exchange risk for us. To mitigate this risk, we enter into forward currency exchange contracts to offset earnings volatility from changes in exchange rates between the Canadian dollar and United States dollar.

The outstanding forward exchange contracts, which had a fair value of $0 million and $(0.2) million at December 31, 2009 and 2008, respectively, have been recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets. For the years ended December 31, 2009 and 2008, respectively, the unrealized foreign exchange gain was $0.2 million and $0.3 million. For the year ended December 31, 2009, the realized foreign currency gain was $1.9 million, while for the year ended December 31, 2008, the amount of foreign currency (loss) was $(1.4) million. Currency transaction gains or losses on transactions executed in Canadian dollars are recorded in Operating revenues on the accompanying Consolidated Statements of Income as incurred.

There were no forward exchange contracts outstanding at December 31, 2009. All forward exchange contracts outstanding at December 31, 2008 were as follows (dollars in thousands):

	Outstanding at December 31, 2009		Outstanding at December 31, 2008	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)

Canadian dollars purchased	$-	-	$52,000	1

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Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty. We adopted the BHCCP for the purpose of establishing guidelines, controls, and limits to manage and mitigate credit risk within risk tolerances established by our Board of Directors. In addition, we have a credit committee which includes senior executives that meet on a regular basis to review our credit activities and monitor compliance with our credit policies.

For energy marketing, production, and generation activities, we attempt to mitigate our credit exposure by conducting business primarily with investment grade companies, setting tenor and credit limits commensurate with counterparty financial strength, obtaining master netting agreements, and mitigating credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit, and other security agreements.

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer's current creditworthiness, as determined by review of their current credit information. We maintain a provision for estimated credit losses based upon historical experience and any specific customer collection issue that is identified.

At December 31, 2009, our credit exposure (exclusive of retail customers of the regulated utilities) was concentrated primarily among investment grade companies. Approximately 77% of the credit exposure was with investment grade companies. The remaining credit exposure was with non-investment grade or non-rated counterparties, of which a portion was supported through letters of credit, prepayments or parental guarantees.

(4) FAIR VALUE MEASUREMENTS

Accounting standards for fair value measurements require, among other things, enhanced disclosures regarding assets and liabilities carried at fair value and also provide a single definition of fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. As permitted under accounting standards for fair value measurements, we utilize a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing a significant portion of the assets and liabilities measured and reported at fair value.

Disclosures are required based on a fair value hierarchy that prioritizes the inputs used to measure fair value. The fair value hierarchy ranks the quality and reliability of the information used to determine fair values giving the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements). We are able to classify fair value balances based on the observability of inputs.

Financial assets and liabilities carried at fair value are classified and disclosed in one of the following three categories:

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

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

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

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect their placement within the fair value hierarchy levels. The following tables set forth, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2009 and 2008 (in thousands):

Recurring Fair Value Measures	At Fair Value as of December 31, 2009				
	Level 1	Level 2	Level 3	Counterparty Netting and Cash Collateral (a)	Total
Assets:					
Commodity derivatives	$-	$154,205	$4,879	$ (117,560)	$41,524
Money market fund	6,000	-	-	-	6,000
Total	$6,000	$154,205	$4,879	$ (117,560)	$47,524
Liabilities:					
Commodity derivatives	$-	$133,604	$5,435	$ (124,078)	$14,961
Interest rate swaps	-	54,204	-	-	54,204
Total	$-	$187,808	$5,435	$ (124,078)	$69,165

Recurring Fair Value Measures	At Fair Value as of December 31, 2008				
	Level 1	Level 2	Level 3	Counterparty Netting and Cash Collateral (a)	Total
Assets:					
Commodity derivatives	$-	$267,932	$28,407	$ (208,952)	$87,387
Liabilities:					
Commodity derivatives	$-	$211,672	$12,009	$ (201,381)	$22,300
Foreign currency derivatives	-	227	-	-	227
Interest rate swaps	-	122,675	-	-	122,675
Total	$-	$334,574	$12,009	$ (201,381)	$145,202

(a) A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Offsetting of fair value amounts recognized for the right to reclaim or the obligation to return cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement is also permitted. Cash collateral on deposit in margin accounts at December 31, 2009 and December 31, 2008 totaled a net $6.5 million and $(7.6) million, respectively.

The following tables present the changes in level 3 recurring fair value for the years ended December 31, 2009 and 2008 (in thousands):

	Commodity Derivatives	
	Year Ended December 31,	
	2009	2008
Balance at beginning of year	$16,398	$6,422
Realized and unrealized (losses) gains	(10,709)	11,059
Purchases, issuance and (settlements)	(164)	(1,083)
Transfers in and/or (out) of level 3(a)	(6,081)	-
Balances at year end	$(556)	$16,398
Changes in unrealized (losses) gain relating to instruments still held as of year end	$(1,836)	$1,886

(a) Transfers into level 3 represent existing assets and liabilities that were previously categorized as a higher level for which the inputs became unobservable. Transfers out of level 3 represent existing assets and liabilities that were previously classified as level 3 for which the lowest significant input became observable during the period.

Gains and losses (realized and unrealized) for level 3 commodity derivatives are included in Operating revenues on the Consolidated Statements of Income. We believe an analysis of commodity derivatives classified as level 3 needs to be undertaken with the understanding that these items may be economically hedged as part of a total portfolio of instruments that may be classified in level 1 or 2, or with instruments that may not be accounted for at fair value. Accordingly, gains and losses associated with level 3 balances may not necessarily reflect trends occurring in the underlying business. Further, unrealized gains and losses for the period from level 3 items may be offset by unrealized gains and losses in positions classified in level 1 or 2, as well as positions that have been realized during the quarter.

As required by accounting standards for derivatives and hedging, fair values within the following tables are presented on a gross basis and do not reflect the netting of asset and liability positions permitted in accordance with accounting standards for offsetting and under terms of our master netting agreements. Further, the amounts do not include net cash collateral of $6.5 million on deposit in margin accounts at December 31, 2009 to collateralize certain financial instruments, which is included in Derivative assets - current. Therefore, the gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not agree with the amounts presented on our Consolidated Balance Sheets, nor will they agree to the fair value measurements presented in Note 3. The following table presents the fair value and balance sheet classification of our derivative instruments as of December 31, 2009 (in thousands):

Fair Value as of December 31, 2009

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets - current	$ 4,163	$ 2,977
Commodity derivatives	Derivative assets - non-current	72	-
Commodity derivatives	Derivative liabilities - current	16	801
Commodity derivatives	Derivative liabilities - non-current	-	55
Interest rate swaps	Derivative liabilities - current	-	6,342
Interest rate swaps	Derivative liabilities - non-current	-	9,075
Total derivatives designated as hedges		$ 4,251	$ 19,250
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets - current	$ 135,807	$ 103,035
Commodity derivatives	Derivative assets - non-current	6,490	2,785
Commodity derivatives	Derivative liabilities - current	19,089	33,069
Commodity derivatives	Derivative liabilities - non-current	946	3,815
Interest rate swap	Derivative liabilities - current	-	38,787
Total derivatives not designated as hedges		$ 162,332	$ 181,491

A description of our derivative activities is discussed in Note 3. The following tables present the impact that derivatives had on our Consolidated Statements of Income for the year ended December 31, 2009.

Fair Value Hedges

The impact of commodity contracts designated as fair value hedges and the related hedged items on our accompanying Consolidated Statements of Income for the year ended December 31, 2009 is presented as follows (in thousands):

Derivatives in Fair Value Hedging Relationships	Location of Gain/(Loss) on Derivatives Recognized in Income	Year Ended December 31, 2009 Amount of Gain/(Loss) on Derivatives Recognized in Income

Commodity derivatives	Operating revenue	$	8,148
Fair value adjustment for natural gas inventory designated as the hedged item	Operating revenue		(9,064)
Total		$	(916)

Cash Flow Hedges

The impact of cash flow hedges on our Consolidated Statements of Income and Balance Sheets for the year ended December 31, 2009 is presented as follows (in thousands):

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	$12,818	Interest expense	$(3,292)		$ -
Commodity derivatives	(21,070)	Operating revenue	23,102	Operating revenue	(1,394)
Total	$(8,252)		$19,810		$ (1,394)

Derivatives Not Designated as Hedge Instruments

The impact of derivative instruments that have not been designated as hedging instruments on our Consolidated Statements of Income for the year ended December 31, 2009 is as follows (in thousands):

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Year Ended December 31, 2009 Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Operating revenue	$ (27,280)
Interest rate swap	Unrealized gain (loss) on interest rate swap	55,653
Foreign currency contracts	Operating revenue	227
		$ 28,600

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(5) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments at December 31, are as follows (in thousands):

	2009		2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$112,901	$112,901	$168,491	$168,491
Restricted cash	$17,502	$17,502	$-	$-
Derivative financial instruments - assets	$41,524	$41,524	$82,867	$82,867
Derivative financial instruments - liabilities	$69,165	$69,165	$140,682	$140,682
Notes payable	$164,500	$164,500	$703,800	$703,800
Long-term debt, including current maturities	$1,051,157	$1,123,703	$503,330	$456,322

The following methods and assumptions were used to estimate the fair value of each class of our financial instruments.

Cash and Cash Equivalents and Restricted Cash

The carrying amount approximates fair value due to the short maturity of these instruments.

Derivative Financial Instruments

These instruments are carried at fair value. The Company's fair value measurements are developed using a variety of inputs by its risk management group, which is independent of the trading function. These inputs include unadjusted quoted prices where available; prices published by various third-party providers; and, when necessary, internally developed adjustments. In many cases, the internally developed prices are corroborated with external sources. Certain Company transactions take place in markets with limited liquidity and limited price visibility. Descriptions of the various instruments we use and the valuation method employed are included in Notes 3 and 4.

Notes Payable

The carrying amount approximates fair value due to their variable interest rates with short reset periods.

Long-Term Debt

The fair value of our long-term debt is estimated based on quoted market rates for debt instruments having similar maturities and similar debt ratings. The first mortgage bonds issued by Black Hills Power and Cheyenne Light are either currently not callable or are subject to make-whole provisions which would eliminate any economic benefits for us to call the bonds.

(6) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment at December 31, consisted of the following (dollars in thousands):

Utilities Group

Electric Utilities	2009	2009 Weighted Average Useful Life	2008	2008 Weighted Average Useful Life	Lives (in years)
Electric plant:					
Production	$537,263	48	$531,872	46	17-62
Transmission	101,223	47	94,115	45	35-56
Distribution	541,611	43	482,518	43	15-65
Plant acquisition adjustment	4,870	32	4,870	32	32
General	98,610	20	63,702	21	5-60
Total electric plant	1,283,577		1,177,077		
Less accumulated depreciation and amortization	337,600		303,273		
Electric plant net of accumulated depreciation and amortization	945,977		873,804		
Construction work in progress	277,274		169,759		
Electric plant, net	$1,223,251		$1,043,563		

Gas Utilities	2009	2009 Weighted Average Useful Life	2008	2008 Weighted Average Useful Life	Lives (in years)
Gas plant:					
Production	$35	37	$72	37	16-41
Transmission	13,923	48	23,299	54	22-60
Distribution	380,149	45	334,146	44	2-65
General	63,930	19	64,167	16	1-49
Total gas plant	458,037		421,684		
Less accumulated depreciation and amortization	33,700		13,328		
Gas plant net of accumulated depreciation and amortization	424,337		408,356		
Construction work in progress	5,228		6,595		
Gas plant, net	$429,565		$414,951		

2009

Non-regulated Energy	Property, Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Property, Plant and Equipment Net of Accumulated Depreciation	Construction Work in Progress	Net Property, Plant and Equipment	Weighted Average Useful Life	Lives (in years)
Coal Mining	$115,400	$ 56,646	$ 58,754	$3,962	$62,716	11	2-39
Oil and Gas	668,383	352,509	315,874	-	315,874	25	3-26
Energy Marketing	2,545	2,302	243	50	293	4	3- 10
Power Generation	131,717	26,262	105,455	16,947	122,402	36	3-40
	$918,045	$ 437,719	$ 480,326	$20,959	$501,285		

2008

Non-regulated Energy	Property, Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Property, Plant and Equipment Net of Accumulated Depreciation	Construction Work in Progress	Net Property, Plant and Equipment	Weighted Average Useful Life	Lives (in years)
Coal Mining	$105,897	$ 49,562	$ 56,335	$1,563	$57,898	11	2-39
Oil and Gas	648,419	281,728	366,691	-	366,691	26	3-27
Energy Marketing	2,375	1,945	430	-	430	3	2-7
Power Generation	154,257	27,197	127,060	4,469	131,529	36	3-40
	$910,948	$ 360,432	$ 550,516	$6,032	$556,548		

Corporate
2009

	Property, Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Property, Plant and Equipment Net of Accumulated Depreciation	Construction Work in Progress	Net Property, Plant and Equipment	Weighted Average Useful Life	Lives (in years)
Corporate	$8,736	$ 6,244	$ 2,492	$ 4,137	$6,629	6	2-10

2008

	Property, Plant and Equipment	Less Accumulated Depreciation, Depletion and	Property, Plant and Equipment Net of Accumulated	Construction Work in Progress	Net Property, Plant and Equipment	Weighted Average Useful Life	Lives (in years)

		Amortization	Depreciation				
Corporate	$ 12,482	$ 6,299	$ 6,183	$ 915	$ 7,098	4	3-10

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(7) JOINTLY OWNED FACILITIES

Oil and Gas

- Through our BHEP subsidiary, we own a 44.7% non-operating interest in the Newcastle Gas Plant (the Gas Plant). The natural gas processing facility gathers and processes approximately 3,000 Mcf/day of gas, primarily from the Finn-Shurley Field in Wyoming. We receive our proportionate share of the Gas Plant's net revenues and are committed to pay our proportionate share of additions, replacements and operating and maintenance expenses. As of December 31, 2009, our investment in the Gas Plant included $4.2 million in plant and equipment and is included in the corresponding caption in the accompanying Consolidated Balance Sheets. This asset is included in the asset pool being depleted and therefore accumulated depreciation is not separated by asset. Our share of revenues of the Gas Plant was $2.3 million, $4.1 million and $2.8 million for the years ended December 31, 2009, 2008 and 2007, respectively. Our share of direct expenses was $0.4 million, $0.4 million and $0.3 million for each of the years ended December 31, 2009, 2008 and 2007. These items are included in the corresponding categories of operating revenues and expenses in the accompanying Consolidated Statements of Income.

Utility Plant

- Our subsidiary, Black Hills Power, owns a 20% interest in the Wyodak plant (the "Plant"), a 362 MW coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp owns the remaining 80% and operates the Plant. Black Hills Power receives 20% of the Plant's capacity and is committed to pay 20% of its additions, replacements and operating and maintenance expenses. Black Hills Power's share of direct expenses of the Plant was $8.0 million, $8.0 million and $7.3 million for the years ended December 31, 2009, 2008 and 2007, respectively, and are included in the corresponding categories of operating expenses in the accompanying Consolidated Statements of Income. As discussed in Note 19, our Coal Mining subsidiary, WRDC, supplies PacifiCorp's share of the coal to the Plant under an agreement expiring in 2022. This coal supply agreement is collateralized by a mortgage on and a security interest in some of WRDC's coal reserves. Under the coal supply agreement, PacifiCorp is obligated to purchase a minimum of 1.5 million tons of coal each year of the contract term, subject to adjustment for planned outages. WRDC's sales to the Plant were $22.8 million, $23.3 million and $21.5 million for the years ended December 31, 2009, 2008 and 2007, respectively.

- Black Hills Power also owns a 35% interest in, and is the operator of, the Converter Station Site and South Rapid City Interconnection (the transmission tie), an AC-DC-AC transmission tie. Basin Electric owns the remaining 65%. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides us with access to both the WECC region and the MAPP region. The total transfer capacity of the tie is 400 MW - 200 MW West to East and 200 MW from East to West. Black Hills Power is committed to pay 35% of the additions, replacements and operating and maintenance expenses. For the year ended December 31, 2009, 2008 and 2007, Black Hills Power's share of direct expenses was $0.1 million for each year.

- On April 9, 2009, Black Hills Power sold to MDU a 25% undivided ownership interest in its 110 MW Wygen III generation facility currently under construction. At closing, MDU made a payment to us for its 25% share of the costs to date on the ongoing construction of the facility. MDU reimburses Black Hills Power monthly for 25% of the total costs paid to complete the project.

- In January 2009, Black Hills Wyoming sold a 23.5% undivided ownership interest in its 90 MW Wygen I to MEAN for a price of $51.0 million, which 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 retain responsibility for plant operations following the transaction. Black Hills Wyoming's share of direct expenses of the Plant was $11.0 million in 2009 and are included in the corresponding categories of Operating expenses in the accompanying Consolidated Statements of Income.

At December 31, 2009, our interests in jointly-owned generating facilities and transmission systems were (dollars in thousands):

	Ownership %		Plant in Service	Construction Work in Progress	Accumulated Depreciation
Wyodak Plant	20.0	%	$79,822	$ 570	$ 52,233
Transmission Tie	35.0	%	19,615	-	3,752
Wygen I	76.5	%	102,559	535	17,229
Wygen III	75.0	%	-	175,586	-
			$201,996	$ 176,691	$ 73,214

(8) LONG-TERM DEBT

Long-term debt outstanding at December 31 is as follows (in thousands):

	2009	2008
Senior unsecured notes:		
Senior unsecured notes at 6.5% due 2013	$225,000	$225,000
Unamortized discount on notes due 2013	(99)	(128)
Senior unsecured notes at 9.0% due 2014	250,000	-
Total senior unsecured notes	474,901	224,872
First mortgage bonds:		
Electric Utilities		
Black Hills Power:		
8.06% due 2010	30,000	30,000
9.49% due 2018	2,520	2,810
9.35% due 2021	19,980	21,645
7.23% due 2032	75,000	75,000
6.125% due 2039	180,000	-
Unamortized discount on 6.125% bonds	(124)	-
Cheyenne Light:		
6.67% due 2037	110,000	110,000
Industrial development revenue bonds due 2021, variable rate, at 0.32% (a)	7,000	7,000
Industrial development revenue bonds due 2027, variable rate, at 0.32% (a)	10,000	10,000
Total first mortgage bonds	434,376	256,455
Other long-term debt:		
Pollution control revenue bonds at 4.8% due 2014	6,450	6,450
Pollution control revenue bonds at 5.35% due 2024	12,200	12,200
Other long-term debt	3,230	3,353
Total other long-term debt	21,880	22,003
Project financing floating rate debt:		
Black Hills Wyoming project due 2016, variable debt rate at 3.49% (a)	120,000	-
Total long-term debt	1,051,157	503,330
Less current maturities	(35,245)	(2,078)
Net long-term debt	$1,015,912	$501,252

(a) Interest rates are presented as of December 31, 2009.

Scheduled maturities of long-term debt, excluding amortization of premium or discount, for the next five years are: $35.2 million in 2010, $7.1 million in 2011, $4.4 million in 2012, $230.9 million in 2013, $264.4 million in 2014 and $509.2 million thereafter.

Certain debt instruments of the Company and its subsidiaries contain restrictions and covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2009.

Substantially all of the tangible utility property of Black Hills Power and Cheyenne Light is subject to the lien of indentures securing their first mortgage bonds. First mortgage bonds of Black Hills Power and Cheyenne Light may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures.

Debt Offering

In May 2009, we issued a $250 million aggregate principal amount of senior unsecured notes due in 2014 pursuant to a public offering. The notes were priced at par and carry a fixed interest rate of 9%. We received proceeds, net of underwriting fees, of $248.5 million. Proceeds were used to pay down the Acquisition Facility. Deferred financing costs of $2.3 million related to the offering were capitalized and are being amortized over the term of the debt. Amortization of these deferred financing costs is included in interest expense and for the year ended December 31, 2009 was approximately $0.3 million.

Industrial Development Revenue Bonds

Cheyenne Light completed a $17 million weekly variable rate refunding bond issuance on September 3, 2009. The new issue replaces existing debt and converted the bond credit support structure from an AMBAC Financial Group insurance policy to a direct-pay letter of credit issued by Wells Fargo Bank. Laramie County, Wyoming was the tax-exempt conduit issuer for this transaction. The bonds were issued in two series: a $10.0 million series maturing March 1, 2027 and a $7.0 million series maturing September 1, 2021. The principal amounts and maturity dates did not change from the original financing. Including the letter of credit fees and other issuance costs, the all-in rate as of December 31, 2009 was approximately 2.69%.

Under the terms of our Reimbursement Agreement with the letter of credit provider, Cheyenne Light is required to maintain a consolidated debt to capitalization ratio of no more than 0.60 to 1.00 and a consolidated interest coverage ratio greater than or equal to 2.50 to 1.00. If Cheyenne Light fails to meet these covenants, subject to a 30-day cure period, it would constitute an event of default and the bank would have the right to cause the bonds and related outstanding obligations to become immediately due and payable.

Black Hills Power Bond Issuance

In October 2009, Black Hills Power completed a $180 million first mortgage bond issuance. The bonds were priced at 99.931% of par with a reoffer yield of 6.13%. The bonds mature on November 1, 2039 and carry an annual interest rate of 6.125%, which will be paid semi-annually. We received proceeds, net of underwriting fees, of $178.3 million which were used to repay borrowings under the Corporate Credit Facility. Deferred financing costs of $2.2 million were capitalized and are being amortized over the term of the bonds.

Black Hills Wyoming

On December 9, 2009, Black Hills Wyoming issued $120 million in project financing debt. Proceeds were used to pay down short-term borrowings on our Corporate Credit Facility. The debt is secured by our ownership interest in the Wygen I plant and Gillette CT generation facility. The loan amortizes over a seven year term and matures on December 9, 2016, at which time the remaining unamortized balance of $83.0 million is due. Principal and interest payments are made on a quarterly basis with the principal payments based on projected cash flows available for debt service. Interest is charged at LIBOR plus 3.25%. Deferred financing costs of $6.1 million were capitalized and are being amortized over the term of the debt. Substantially all of the assets of Black Hills Wyoming are subject to the lien securing the project financing debt.

Our Black Hills Wyoming project financing is secured by our ownership interest in the Wygen I plant and by the Gillette CT generation facility. The financing places restrictions on dividends or the loaning of funds by Black Hills Wyoming, and allows it only in limited circumstances when cash flows for the projects exceed project debt service and reserve requirements. We had approximately $39.1 million of equity at Black Hills Wyoming as of December 31, 2009.

(9) NOTES PAYABLE

Our credit facilities and debt securities contain certain restrictive financial covenants including, among others, interest expense coverage ratios, recourse leverage ratios and consolidated net worth ratios. At December 31, 2009, we were in compliance with these financial covenants. None of our facilities or debt securities contains default provisions pertaining to our credit ratings.

Corporate Credit Facility

Black Hills Corporation had a committed line of credit with various banks totaling $525.0 million at December 31, 2009 and 2008, respectively. Our credit line is a revolving credit facility, which expires May 4, 2010. The lenders' commitments under this credit facility were increased from $400.0 million to $525.0 million in July 2008. We had $164.5 million of borrowings and $44.8 million of letters of credit and $321.0 million of borrowings and $60.7 million of letters of credit issued under the facility at December 31, 2009 and 2008, respectively. The cost of borrowings or letters of credit issued under the facility is determined based on our credit ratings. At our current ratings levels, the facility has an annual facility fee of 17.5 basis points, and has a borrowing spread of 70 basis points over LIBOR (which equates to a 0.93% one-month borrowing rate as of December 31, 2009). We have no compensating balance requirements associated with this credit facility.

Enserco Credit Facility

In May 2009, Enserco entered into a $300 million committed credit facility. This credit facility expires on May 7, 2010 and is a borrowing base line of credit, which allows for the issuance of letters of credit and for borrowings. Maximum borrowings under the facility are subject to a sublimit of $50 million. Borrowings under this facility are available under a base rate option or a Eurodollar option. The base rate option borrowing rate is 2.75% plus the higher of: (i) 0.5% above the Federal Funds Rate, or (ii) the prime rate established by Fortis Bank S.A./N.V. The Eurodollar option borrowing rate is 2.75% plus the higher of the Eurodollar Rate or the reference bank cost of funds.

At December 31, 2009, $103.0 million of letters of credit were issued and outstanding under this facility and there were no cash borrowings outstanding. Deferred financing costs of $2.0 million were capitalized and are amortized over the life of the facility. Amortization of deferred financing costs included in Interest expense for the year ended December 31, 2009 was approximately $1.4 million. For the year ended December 31, 2008, under our previous uncommitted Enserco Credit Facility, amortization of deferred financing costs was $0.6 million.

Acquisition Facility

In July 2008, in conjunction with the closing of the Aquila Transaction, we borrowed $382.8 million under our $1 billion bridge acquisition credit facility dated May 7, 2007. The Acquisition Facility was structured as a single-draw term loan facility for the sole purpose of financing the Aquila Transaction. During 2009, we repaid the Acquisition Facility with proceeds of $30.2 million for the sale of 25% of the Wygen III plant to MDU, net proceeds from the $250 million public debt offering, and with a borrowing of $104.6 million on our Corporate Credit Facility.

(10) ASSET RETIREMENT OBLIGATIONS

Accounting standards for asset retirement obligations associated with long-lived assets requires that the present value of retirement costs for which we have a legal obligation be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The liability is then accreted over time by applying an interest method of allocation to the liability. The associated ARO accretion expense is included within Depreciation, depletion and amortization on the accompanying Consolidated Statements of Income. The recording of the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset pursuant to accounting standards for regulated operations. We have identified legal retirement obligations related to plugging and abandonment of natural gas and oil wells in the Oil and Gas segment, reclamation of coal mining sites at the Coal Mining segment and removal of fuel tanks, asbestos and transformers containing polychlorinated biphenyls at the regulated Electric Utilities segment and asbestos at our regulated Gas Utilities segment.

The following table presents the details of our ARO which are included on the accompanying Consolidated Balance Sheets in Other deferred credits and other liabilities (in thousands):

	Balance at 12/31/08	Liabilities Incurred	Liabilities Settled	Accretion	Balance at 12/31/09
Oil and Gas	$19,623	$623	$(239)	$1,226	$21,233
Coal Mining	17,699	1,882	(5,414)	1,118	15,285
Electric Utilities	2,616	-	-	288	2,904
Gas Utilities	222	-	-	19	241
Total	$40,160	$2,505	$(5,653)	$2,651	$39,663

	Balance at 12/31/07	Liabilities Incurred	Liabilities Settled	Accretion	Balance at 12/31/08
Oil and Gas	$14,952	$5,029	$(1,213)	$855	$19,623
Coal Mining	14,778	4,121	(1,839)	639	17,699
Electric Utilities	180	2,381 *	-	55	2,616
Gas Utilities	-	213 *	-	9	222
Total	$29,910	$11,744	$(3,052)	$1,558	$40,160

* This balance was recorded as part of the purchase price allocation of the Aquila acquisition (see Note 23).

We also have legally required asset retirement obligations related to certain assets within our electric and gas utility transmission and distribution systems. These retirement obligations are pursuant to an easement or franchise agreement and are only required if we discontinue our utility service under such easement or franchise agreement. Accordingly, it is not possible to estimate a time period when these obligations could be settled and therefore, a value for the cost of these obligations cannot be measured at this time.

(11) COMMON STOCK

Equity Compensation Plans

We have several employee equity compensation plans, which allow for the granting of stock, restricted stock, restricted stock units, stock options and performance shares. We had 751,996 shares available to grant at December 31, 2009.

Compensation expense is determined using the grant date fair value estimated in accordance with the provisions of accounting standards for stock compensation and is recognized over the vesting periods of the individual plans. Total stock-based compensation expense for the years ended December 31, 2009, 2008 and 2007 was $4.0 million ($2.6 million, after-tax), $1.3 million ($0.9 million, after-tax) and $5.8 million ($3.8 million, after-tax), respectively, and is included in Administrative and general expense on the accompanying Consolidated Statements of Income. As of December 31, 2009, total unrecognized compensation expense related to non-vested stock awards was $5.2 million and is expected to be recognized over a weighted-average period of 1.8 years.

Stock Options

We have granted options with an option exercise price equal to the fair market value of the stock on the day of the grant. The options granted vest one-third each year for three years and expire ten years after the grant date.

A summary of the status of the stock option plans at December 31, 2009 is as follows:

	Shares (in thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Balance at January 1, 2009	435	$ 30.01		
Granted	-	-		
Forfeited/cancelled	(3)	24.06		
Expired	(17)	23.97		
Exercised	(79)	22.05		
Balance and exercisable at December 31, 2009	336	$ 32.24	2.9	$(1,885)

No options were granted for the years ended December 31, 2009, 2008 and 2007, respectively. The total intrinsic value of options (the amount by which the market price of the stock on the date of exercise exceeded the exercise price of the option) exercised during the years ended December 31, 2009, 2008 and 2007 was $0.3 million, $1.2 million and $1.9 million, respectively. The total fair value of shares vested during the years ended December 31, 2009, 2008 and 2007 was immaterial. As of December 31, 2009, there was no unrecognized compensation expense related to stock options.

Net cash received from the exercise of options for the years ended December 31, 2009, 2008 and 2007 was $1.7 million, $2.0 million and $4.7 million, respectively. The tax benefit realized from the exercise of shares granted for the years ended December 31, 2009, 2008 and 2007 was $0.1 million, $0.4 million and $0.7 million, respectively, and was recorded as an increase to equity.

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Restricted Stock and Restricted Stock Units

The fair value of restricted stock and restricted stock unit awards equals the market price of our stock on the date of grant.

The shares carry a restriction on the ability to sell the shares until the shares vest. The shares substantially vest one-third per year over three years, contingent on continued employment. Compensation cost related to the awards is recognized over the vesting period.

A summary of the status of the restricted stock and non-vested restricted stock units at December 31, 2009 is as follows:

	Stock and Stock Units (in thousands)	Weighted-Average Grant Date Fair Value
Balance at January 1, 2009	172	$ 33.69
Granted	89	26.76
Vested	(69)	34.99
Forfeited	(6)	32.98
Balance at December 31, 2009	186	$ 29.92

The weighted-average grant-date fair value of restricted stock and restricted stock units granted and the total fair value of shares vested during the years ended December 31, 2009, 2008 and 2007 was as follows:

	Weighted-Average Grant Date Fair Value	Total Fair Value of Shares Vested (in thousands)
2009	$ 26.76	$1,799
2008	$ 32.39	$2,061
2007	$ 38.67	$1,975

As of December 31, 2009, there was $3.7 million of unrecognized compensation expense related to non-vested restricted stock and non-vested restricted stock units that is expected to be recognized over a weighted-average period of 1.8 years.

Performance Share Plan

Certain officers of the Company and its subsidiaries are participants in a performance share award plan, a market-based plan. Performance shares are awarded based on the Company's total shareholder return over designated performance periods as measured against a selected peer group. In addition, our stock price must also increase during the performance periods.

Participants may earn additional performance shares if the Company's total shareholder return exceeds the 50th percentile of the selected peer group. The final value of the performance shares may vary according to the number of shares of common stock that are ultimately granted based upon the performance criteria.

Outstanding Performance Periods at December 31, 2009 are as follows (in thousands):

Grant Date	Performance Period	Target Grant of Shares
January 1, 2007	January 1, 2007 - December 31, 2009	28
January 1, 2008	January 1, 2008 - December 31, 2010	27
January 1, 2009	January 1, 2009 - December 31, 2011	77

The performance awards are paid 50% in cash and 50% in common stock. The cash portion accrued is classified as a liability and the stock portion is classified as equity. In the event of a change-in-control, performance awards are paid 100% in cash. If it is determined that a change-in-control is probable, the equity portion of $1.3 million at December 31, 2009 would be reclassified as a liability.

A summary of the status of the Performance Share Plan at December 31, 2009 and changes during the year ended December 31, 2009, is as follows:

	Equity Portion		Liability Portion	
	Shares (in thousands)	Weighted-Average Grant Date Fair Value	Shares (in thousands)	Weighted-Average December 31, 2009 Fair Value
Balance at January 1, 2009	42	$ 37.51	42	
Granted	39	29.20	39	
Forfeited	(2)	35.05	(2)	
Vested	(13)	32.06	(13)	
Balance at December 31, 2009	66	$ 33.67	66	$13.31

The grant date fair value for the performance shares granted in 2009, 2008 and 2007 were determined by Monte Carlo simulation using a blended volatility of 39%, 23% and 20%, respectively, comprised of 50% historical volatility and 50% implied volatility and the average risk-free interest rate of the three-year United States Treasury security rate in effect as of the grant date. The weighted-average grant-date fair value of performance share awards granted in the years ended December 31, 2009, 2008 and 2007 was as follows:

	Weighted Average Grant Date Fair Value
2009	$29.20
2008	$46.00
2007	$34.17

Performance plan payouts have been as follows (dollars and shares in thousands):

Performance Period	Year of Payment	Stock Issued	Cash Paid	Total Intrinsic Value
January 1, 2006 to December 31, 2008	2009	-	$-	$-
January 1, 2005 to December 31, 2007	2008	35	$1,526	$3,051
March 1, 2004 to December 31, 2006	2007	4	$160	$320

On January 27, 2010, the Compensation Committee of our Board of Directors determined that the plan criteria for the January 1, 2007 to December 31, 2009 performance period was not met. As a result, there will be no payout for this performance period.

As of December 31, 2009, there was $1.5 million of unrecognized compensation expense related to outstanding performance share plans that is expected to be recognized over a weighted-average period of 1.9 years.

Dividend Reinvestment and Stock Purchase Plan

We have a Dividend Reinvestment and Stock Purchase Plan under which shareholders may purchase additional shares of common stock through dividend reinvestment and/or optional cash payments at 100% of the recent average market price. We have the option of issuing new shares or purchasing the shares on the open market. In March 2009, we began issuing new shares. In 2009, 143,333 new shares were issued at a weighted-average price of $21.63. There are 295,983 shares of unissued common stock available for future offerings under the Plan.

Other Plans

We issued 47,331 fully-vested shares of common stock with an intrinsic value of $0.7 million in the year ended December 31, 2009 to certain key employees under the Short-term Annual Incentive Plan, a performance-based plan. The payout was fully accrued at December 31, 2008. We issued 32,568 and 33,143 shares of common stock in 2008 and 2007, respectively, under the Short-term Annual Incentive Plan.

In addition, we will issue common stock with an intrinsic value of approximately $0.4 million in 2010 for the 2009 Short-term Annual Incentive Plan.

Private Placement of Common Stock

In 2007, we completed the issuance and sale of approximately 4.17 million shares of common stock at a price of $36.00 per share in a private placement offering. We used approximately $145.6 million of net proceeds from this offering for debt reduction. Subsequently, the shares were registered for resale under the Securities Act of 1933 and at December 31, 2009, the shares are freely tradable by non-affiliates of the Company.

Issuance of Unregistered Securities

In 2008, we issued 593,804 common shares as additional consideration associated with the Earn-out Litigation described in Note 1. No additional consideration was received in exchange for the earn-out shares.

Dividend Restrictions

Our revolving credit facility contains restrictions on the payment of cash dividends upon a default or event of default. An event of default would be deemed to have occurred if we did not meet certain financial covenants. The most restrictive financial covenants include the following: interest expense coverage ratio of not less than 2.5 to 1.0; a recourse leverage ratio not to exceed 0.65 to 1.00; and a minimum consolidated net worth of $625 million plus 50% of aggregate consolidated net income since January 1, 2005. As of December 31, 2009, we were in compliance with the above covenants.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our shareholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. The following restrictions on distributions from our subsidiaries existed at December 31, 2009:

- Our utility subsidiaries are generally limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As of December 31, 2009, the restricted net assets at our regulated Electric and regulated Gas Utilities were approximately $277.0 million.

- In 2009, one of the covenants to the Enserco Credit Facility was amended to temporarily increase the allowable rolling twelve month Net Cumulative Loss as calculated on a non-GAAP basis and temporarily restrict all dividends or loans to the Company. This amendment expired on December 31, 2009 and is not a requirement under the Facility subsequent to December 31, 2009. Upon review of the covenants, restricted net assets at Enserco total $205.8 million for this stand-alone Enserco Credit Facility at December 31, 2009.

Treasury Shares

We acquired 6,088 shares, 15,107 shares and 767 shares of treasury stock related to forfeitures of unvested restricted stock in 2009, 2008 and 2007, respectively, and 21,569 shares, 17,233 shares and 16,418 shares related to the share withholding for the payment of taxes associated with the vesting of restricted shares and stock option exercise stock swaps in 2009, 2008 and 2007, respectively.

We utilized 59,006 shares, 38,073 shares and 8,030 shares of treasury stock in 2009, 2008 and 2007, respectively, related to grants from the different equity plans.

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(12) IMPAIRMENT OF LONG LIVED ASSETS, GOODWILL AND CAPITALIZED DEVELOPMENT COSTS

Oil and Gas Segment

As a result of lower natural gas prices at March 31, 2009, we recorded a $43.3 million pre-tax non-cash ceiling test impairment of oil and gas assets included in the Oil and Gas segment. The write-down in the net carrying value of our natural gas and crude oil properties was recorded in Impairment of long-lived assets on the accompanying Consolidated Statements of Income and was based on the March 31, 2009 NYMEX price of $3.63 per Mcf, adjusted to $2.23 per Mcf at the wellhead, for natural gas; and NYMEX price of $49.66 per barrel, adjusted to $45.32 per barrel at the wellhead, for crude oil.

Also, as a result of low crude oil and natural gas prices at the end of 2008, we recorded a $91.8 million pre-tax non-cash ceiling test impairment charge of oil and gas assets included in the Oil and Gas segment. The write-down in the net carrying value of our natural gas and crude oil property was recorded as impairment expense and was based on the December 31, 2008 NYMEX price of $5.71 per Mcf, adjusted to $4.44 per Mcf at the wellhead, for natural gas; and $44.60 per barrel, adjusted to $32.74 per barrel at the wellhead, for crude oil.

Idaho Operation

In December 2007, the Rupert and Glenns Ferry partnerships, in which we have 50% ownership interests, impaired the carrying amounts of their property, plant and equipment to reflect the partnerships' assessment of the recoverability of their respective carrying amounts. We account for these investments using the equity method of accounting. Accordingly, our carrying amount for these investments was reduced by $3.9 million to reflect the increased losses from the partnerships' impairment charges. In addition, we wrote off $0.6 million of net goodwill impairment directly related to our investments in the partnerships. At December 31, 2007, our remaining carrying amount for these partnership investments was nominal. Our investment in the Rupert and Glenns Ferry partnership is included in the Power Generation segment.

Ontario Operations

During September 2007, we assessed the recoverability of the carrying value of the Ontario power plant due to the pending thermal host contract expiration without a long-term extension. The carrying amount of the assets tested for impairment was $1.3 million. The assessment resulted in an impairment charge of $1.3 million, primarily for net property, plant and equipment and intangible assets. This charge reflects the amount by which the carrying value of the facility exceeded its estimated fair value determined by future discounted cash flow estimates. In addition, $1.4 million was accrued for a contract termination payment and other related costs. These charges were included as a component of Operating expenses on the accompanying Consolidated Statements of Income. Operating results from the Ontario plant are included in the Power Generation segment through December 31, 2009, when the plant was decommissioned.

(13) OPERATING LEASES

We have entered into agreements relating to vehicle leases and office facility leases. Rental expense incurred under these operating leases was $4.5 million, $3.5 million and $0.8 million for the years ended December 31, 2009, 2008 and 2007, respectively.

The following is a schedule of future minimum payments required under the operating lease agreements (in thousands):

2010	$2,612
2011	1,879
2012	1,669
2013	1,271
2014	1,237
Thereafter	6,532
	$15,200

(14) INCOME TAXES

Income tax expense (benefit) from continuing operations for the years indicated was (in thousands):

	2009	2008	2007
Current:			
Federal	$(6,124)	$(215,957)	$22,605
State	(222)	(1,330)	246
Foreign(1)	(82)	1,179	2,114
	(6,428)	(216,108)	24,965
Deferred:			
Federal	40,219	185,614	7,405
State	(108)	1,414	349
Tax credit amortization	(368)	(315)	(292)
	39,743	186,713	7,462
	$33,315	$(29,395)	$32,427

(1) Foreign taxes represent income taxes incurred through our Canadian activities.

2008 amounts reflect the income tax impacts associated with our like-kind exchange tax planning structure. The tax planning structure allowed us to defer approximately $185 million of income taxes related to the IPP Transaction which would have been payable for the 2008 tax year without such a structure.

The temporary differences, which gave rise to the net deferred tax liability, were as follows (in thousands):

Years ended December 31,	2009	2008
Deferred tax assets, current:		
Asset valuation reserves	$1,651	$2,366
Mining development and oil exploration	779	896
Unbilled revenue	581	581
Employee benefits	4,993	5,839
Items of other comprehensive income	3,872	1,717
Derivative fair value adjustments	12,596	33,054
Other deferred tax assets, current	2,940	142
Total deferred tax assets, current	27,412	44,595
Deferred tax liabilities, current:		
Prepaid expenses	2,121	2,139
Derivative fair value adjustments	3,740	12,252
Items of other comprehensive income	3,273	6,566
Deferred costs	5,132	10,369
Other deferred tax liabilities, current	8,623	3,025
Total deferred tax liabilities, current	22,889	34,351
Net deferred tax asset, current	$4,523	$10,244
Deferred tax assets, non-current:		
Employee benefits	$17,191	$17,838
Regulatory liabilities	22,844	28,381
Deferred revenue	526	591
Deferred costs	471	79
State net operating loss	2,813	342
Items of other comprehensive income	10,535	15,872
Foreign tax credit carryover	2,966	3,591
Net operating loss (net of valuation allowance)	8,023	7,816
Asset impairment	47,557	32,607
Derivative fair value adjustment	902	-
Other deferred tax assets, non-current	10,622	8,794
Total deferred tax assets, non-current	124,450	115,911
Deferred tax liabilities, non-current:		
Accelerated depreciation, amortization and other plant-related differences	237,578	200,119
Regulatory assets	34,097	36,088
Mining development and oil exploration	101,407	94,994
Deferred costs	9,491	352
Derivative fair value adjustments	1,254	221
Items of other comprehensive income	2,657	4,139
Other deferred tax liabilities, non-current	-	3,605
Total deferred tax liabilities, non-current	386,484	339,518
Net deferred tax liability, non-current	$262,034	$223,607

Net deferred tax liability	$257,511	$213,363

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The following table reconciles the change in the net deferred income tax liability from December 31, 2008 to December 31, 2009 to deferred income tax expense (in thousands):

	2009	2008
Net change in net deferred income tax liability from the preceding table	$44,148	$10,140
Deferred taxes associated with other comprehensive income	(941)	(1,773)
Deferred taxes related to net operating loss from acquisition	-	2,071
Deferred taxes associated with IPP Transaction	-	48,131
Deferred taxes related to regulatory assets and liabilities	(3,565)	(1,333)
Deferred taxes related to acquisition	7,992	13,422
Deferred taxes associated with property basis differences	(9,013)	114,170
Other net deferred income tax liability	1,122	1,885
Deferred income tax expense for the period	$39,743	$186,713

The effective tax rate differs from the federal statutory rate for the years ended December 31, as follows:

	2009	2008	2007
Federal statutory rate	35.0 %	(35.0)%	35.0 %
State income tax (net of federal tax effect)	(0.2)	-	0.4
Amortization of excess deferred and investment tax credits	(0.3)	(0.4)	(0.4)
Percentage depletion in excess of cost	(0.8)	-	(1.3)
Equity AFUDC	(1.7)	(1.4)	(1.6)
State exam tax adjustment*	-	-	(0.6)
Tax credits	-	-	(0.3)
Accounting for uncertain tax positions adjustment	(2.1)	-	-
Other tax differences	(0.2)	0.8	(1.1)
	29.7 %	(36.0)%	30.1 %

* As a result of state tax exam settlements for the 2001-2003 tax years, a tax benefit of approximately $0.7 million (net of the federal tax effect) was recorded in 2007.

At December 31, 2009, we had the following remaining NOL carryforwards which were acquired as part of our 2003 acquisition of Mallon Resources Corporation (Mallon) (in thousands):

Net Operating Loss Carryforward	Expiration Year
$1,685	2021
$17,146	2022
$3,104	2023

As of December 31, 2009, we had a valuation allowance of $1.2 million against these NOL carryforwards. Ultimate usage of these NOL's depends upon our future tax filings. If the valuation allowance is adjusted due to higher or lower than anticipated utilization of the NOL's, the offsetting amount would affect our financial reporting basis in the acquired Mallon properties.

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We adopted the accounting standards for uncertain tax positions on January 1, 2007 which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with accounting standards for income taxes and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken. As a result of this implementation, we recognized an approximate $0.7 million benefit from a decrease in the liability for unrecognized tax benefits. This benefit was accounted for as an adjustment to the January 1, 2007 balance of retained earnings.

The following table reconciles the total amounts of unrecognized tax benefits at the beginning and end of the period included in Other deferred credits and other liabilities on the accompanying Consolidated Balance Sheets (in thousands):

	2009	2008	2007
Beginning balance at December 31	$120,022	$75,770	$72,583
Additions for prior year tax positions	5,752	5,015	4,719
Reductions for prior year tax positions	(18,686)	(72,948)	(46)
Additions for current year tax positions	-	112,185	623
Settlements	-	-	(2,109)
Ending balance at December 31	107,088	120,022	75,770
Income tax refund receivable related to uncertain tax positions above	(59,136)	(60,612)	-
Net liability for uncertain tax positions	$47,952	$59,410	$75,770

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $0.4 million.

It is our continuing practice to recognize interest and/or penalties related to income tax matters in income tax expense. During the years ended December 31, 2009, 2008 and 2007, we recognized approximately $1.2 million, $0.5 million and $0.1 million, respectively of interest expense. We had approximately $0.8 million accrued for interest payable and $0.4 million accrued for interest receivable at December 31, 2009 and 2008, respectively.

We file income tax returns with the IRS, various state jurisdictions and Canada. We are currently under examination by the IRS for the 2004, 2005 and 2006 tax years. We remain subject to examination by Canadian income tax authorities for tax years as early as 1999.

We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of any audits or the expiration of statute of limitations prior to December 31, 2010.

In 2005, Canadian income tax returns were filed for the years of 1999 - 2003. Excess foreign tax credits were generated and are available to offset United States federal income taxes. At December 31, 2009, we had the following remaining foreign tax credit carryforwards (in thousands):

Foreign Tax Credit Carryforward	Expiration Year

$31	2014
$694	2015
$940	2016
$1,301	2017

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(15) COMPREHENSIVE INCOME

The following table displays the related tax effects allocated to each component of Other comprehensive income (loss) for the years ended December 31 (in thousands):

2009	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum pension liability adjustments	$6,922	$(2,431)	$4,491
Fair value adjustment of derivatives designated as cash flow hedges	(27,442)	9,961	(17,481)
Reclassification adjustments of cash flow hedges settled and included in net income	19,810	(7,201)	12,609
Other comprehensive income (loss)	$(710)	$329	$(381)

2008	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum pension liability adjustments	$(12,343)	$4,331	$(8,012)
Fair value adjustment of derivatives designated as cash flow hedges	(15,353)	5,224	(10,129)
Reclassification adjustments of cash flow hedges dedesignated and included in net income	42,710	(14,949)	27,761
Reclassification adjustments of cash flow hedges settled and included in net income	(5,992)	2,097	(3,895)
Other comprehensive income (loss)	$9,022	$(3,297)	$5,725

2007	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum pension liability adjustments	$3,513	$(1,224)	$2,289
Fair value adjustment of derivatives designated as cash flow hedges	(58,603)	20,212	(38,391)
Reclassification adjustments of cash flow hedges settled and included in net income	14,228	(4,910)	9,318
Reclassification adjustments for cash flow hedges settled and included in regulatory assets	4,288	(1,497)	2,791
Other comprehensive income (loss)	$(36,574)	$12,581	$(23,993)

Balances by classification included within Accumulated other comprehensive loss on the accompanying Consolidated Balance Sheets are as follows (in thousands):

	Derivatives Designated	Employee Benefit	Amount from Equity-method	Total

	as Cash Flow Hedges	Plans	Investees	
As of December 31, 2009	$(9,462)	$(9,636)	$ (66)	$(19,164)
As of December 31, 2008	$(4,522)	$(14,127)	$ (134)	$(18,783)

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(16) SUPPLEMENTAL CASH FLOW INFORMATION

Years ended December 31,	2009	2008 (in thousands)	2007
Non-cash investing and financing activities-			
Property, plant and equipment acquired with accrued liabilities	$24,571	$23,067	$19,734
Issuance of common stock for earn-out settlement (see Note 20)	$-	$19,694	$-
Refunding bond issuance – Industrial Development Revenue Bonds (see Note 8)	$17,000	$-	$-
Cash paid during the period for-			
Interest (net of amount capitalized)	$71,891	$55,864	$44,700
Income taxes paid (refunded)	$(23,231)	$32,988	$14,204

(17) BUSINESS SEGMENTS

Our reportable segments are based on our method of internal reporting, which generally segregates the strategic business groups due to differences in products, services and regulation. As of December 31, 2009, with the exception of our energy marketing operations in Canada, all of our operations and assets are located within the United States.

The Company conducts its operations through the following six reportable segments:

Utilities Group -

- Electric Utilities, which supply regulated electric utility service to areas in South Dakota, Wyoming, Colorado and Montana and natural gas utility services to Cheyenne, Wyoming and vicinity; and

- Gas Utilities, which supply regulated gas utility service to Colorado, Iowa, Kansas and Nebraska. The regulated Gas Utilities were acquired in July 2008 as described in Note 23.

Non-regulated Energy Group -

- Oil and Gas, which produces, explores and operates oil and natural gas interests located in Colorado, Louisiana, Montana, Oklahoma, Nebraska, New Mexico, North Dakota, Wyoming, Texas and California;

- Power Generation, which produces and sells power and capacity to wholesale customers. The power plants are located in Wyoming and Idaho;

- Coal Mining, which engages in the mining and sale of coal from its mine near Gillette, Wyoming; and

- Energy Marketing, which markets natural gas, crude oil and related services primarily in the United States and Canada.

On July 11, 2008, we sold entities that owned seven IPP plants with a total capacity of 974 megawatts. The financial information related to these plants was previously reported in the Power Generation segment and has been reclassified to discontinued operations. Our remaining IPP assets continue to be reported in the Power Generation segment.

December 31:	2009	2008
	(in thousands)	
Total assets		
Utilities:		
Electric Utilities	$1,659,375	$1,485,040
Gas Utilities	684,375	733,377
Non-regulated Energy:		
Oil and Gas	338,470	403,583
Power Generation	161,856	155,819
Coal Mining	76,209	75,872
Energy Marketing	321,207	339,543
Corporate	76,206	186,409
Discontinued operations	-	246
Total assets	$3,317,698	$3,379,889
Capital expenditures and asset acquisitions		
Acquisition costs:		
Payment for acquisition of net assets, net of cash acquired	$-	$938,423
Utilities:		
Electric Utilities	241,963	186,237
Gas Utilities	43,005	19,337
Non-regulated Energy:		
Oil and Gas	20,522	89,169
Power Generation	20,537	5,105
Coal Mining	11,765	25,190
Energy Marketing	220	22
Corporate	9,807	11,033
Capital expenditures of continuing operations	347,819	1,274,516
Capital expenditures of discontinued operations	-	29,836
Total capital expenditures and asset acquisitions	$347,819	$1,304,352
Property, plant and equipment		
Utilities:		
Electric Utilities	$1,560,851	$1,346,836
Gas Utilities	463,265	428,279
Non-regulated Energy:		
Oil and Gas	668,383	648,419
Power Generation	148,664	158,726
Coal Mining	119,362	107,460
Energy Marketing	2,595	2,375
Corporate	12,873	13,397
Total property, plant and equipment	$2,975,993	$2,705,492

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	2009	2008 (in thousands)	2007
External operating revenues			
Utilities:			
Electric Utilities	$519,892	$472,174	$301,514
Gas Utilities	580,312	277,076	-
Non-regulated Energy:			
Oil and Gas	70,684	106,347	101,522
Power Generation	30,575	38,011	38,658
Coal Mining	31,459	31,842	26,154
Energy Marketing	13,381	59,310	93,836
Corporate		-	-
Total external operating revenues	$1,246,303	$984,760	$561,684
Intersegment operating revenues			
Utilities:			
Electric Utilities	$873	$1,245	$1,897
Non-regulated Energy:			
Power Generation	-	170	-
Coal Mining	27,031	25,059	16,334
Corporate	-	267	-
Intersegment eliminations	(4,629)	(5,711)	(5,077)
Total intersegment operating revenues(a)	$23,275	$21,030	$13,154

(a)In accordance with the accounting standards for regulated operations, intercompany fuel and energy sales to our regulated utilities are not eliminated.

December 31:	2009	2008 (in thousands)	2007
Depreciation, depletion and amortization			
Utilities:			
Electric Utilities	$43,638	$37,648	$25,517
Gas Utilities	30,090	14,142	-
Non-regulated Energy:			
Oil and Gas	29,680	38,549	34,192
Power Generation	3,860	4,627	5,051
Coal Mining	13,123	9,449	5,016
Energy Marketing	525	689	813
Corporate	381	2,159	1,178
Total depreciation, depletion and amortization	$121,297	$107,263	$71,767

December 31:	2009		2008 (in thousands)		2007	
Operating income (loss)						
Utilities:						
Electric Utilities	$70,968		$77,866		$53,312	
Gas Utilities	55,210		14,888		-	
Non-regulated Energy:						
Oil and Gas	(42,521	)(a)	(71,188	)(b)	25,437	
Power Generation	40,055	(c)	14,215		2,596	
Coal Mining	5,055		4,293		6,177	
Energy Marketing	(423	)	30,135		51,769	
Corporate	(1,998	)	(13,682	)	(13,576	)
Intersegment eliminations	486		(650	)	-	
Total operating income	$126,832		$55,877		$125,715	

(a) As a result of lower natural gas prices at March 31, 2009, we recorded a $43.3 million non-cash ceiling test impairment of oil and gas assets in the first quarter of 2009 (see Note 12).
(b) As a result of low crude oil and natural gas prices at the end of 2008, we recorded a $91.8 million non-cash ceiling test impairment of oil and gas assets (see Note 12).
(c) Includes $26.0 million pre-tax gain on sale to MEAN of a 23.5% ownership interest in the Wygen I power generation facility.

December 31:	2009		2008 (in thousands)		2007	
Interest income						
Utilities:						
Electric Utilities	$1,818		$2,041		$7,282	
Gas Utilities	264		376		-	
Non-regulated Energy:						
Oil and Gas	10		215		317	
Power Generation	1,856		8,951		20,180	
Coal Mining	1,476		1,392		2,074	
Energy Marketing	787		1,345		3,308	
Corporate	27,222		47,425		60,138	
Intersegment eliminations	(31,821	)	(59,569	)	(89,734	)
Total interest income	$1,612		$2,176		$3,565	
Interest expense						
Utilities:						
Regulated Electric Utilities	$34,830		$25,335		$21,012	
Regulated Gas Utilities	17,364		8,501		-	
Non-regulated Energy:						
Oil and Gas	4,683		5,307		8,974	
Power Generation	11,244		20,600		26,098	
Coal Mining	24		46		390	
Energy Marketing	2,334		1,599		1,177	
Corporate	46,032		52,304		57,264	
Intersegment eliminations	(31,821	)	(59,569	)	(89,734	)

Total interest expense	$84,690	$54,123	$25,181

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December 31:	2009		2008 (in thousands)		2007	
Income taxes						
Utilities:						
Electric Utilities	$13,126		$18,882		$12,826	
Gas Utilities	13,453		2,447		-	
Non-regulated Energy:						
Oil and Gas	(21,016	)	(26,001	)	5,182	
Power Generation	11,097		3,013		(2,625	)
Coal Mining	3,234		2,190		2,091	
Energy Marketing	(460	)	10,180		19,746	
Corporate	13,881		(40,106	)	(4,793	)
Intersegment eliminations	-		-		-	
Total income tax expense (benefit)	$33,315		$(29,395	)	$32,427	
Income (loss) from continuing operations						
Utilities:						
Electric Utilities	$32,699		$39,674		$31,633	
Gas Utilities	24,372		4,230		-	
Non-regulated Energy:						
Oil and Gas	(25,828	)(a)	(49,668	)(b)	12,706	
Power Generation	20,661	(c)	3,251		(3,094	)
Coal Mining	6,748		4,033		6,107	
Energy Marketing	(1,488	)	19,689		34,178	
Corporate	21,106	(d)	(72,596	)(d)	(5,872	)
Intersegment eliminations	486		(650	)	-	
Total income (loss) from continuing operations	$78,756		$(52,037	)	$75,658	

(a) As a result of lower natural gas prices at March 31, 2009, we recorded a $27.8 million after-tax non-cash ceiling test impairment of oil and gas assets in the first quarter of 2009 (see Note 12).

(b) As a result of low crude oil and natural gas prices at the end of 2008, we recorded a $59.0 million after-tax non-cash ceiling test impairment of oil and gas assets (see Note 12).

(c) Includes $16.9 million after-tax gain on sale to MEAN of a 23.5% ownership interest in the Wygen I power generation facility.

(d) Includes $36.2 million after-tax net mark-to-market gain for the year ended December 31, 2009 and a $61.4 million after-tax net mark-to-market loss for the year ended December 31, 2008.

(18) EMPLOYEE BENEFIT PLANS

Defined Contribution Plans

We sponsor a 401(k) retirement savings plan. Participants in the Plan may elect to invest a portion of their eligible compensation to the Plan up to the maximum amounts established by the IRS. The Plan provides the following benefits:

Cheyenne Light employees may elect to invest up to 50% of their eligible compensation on a pre-tax or after-tax basis. Cheyenne employee contributions are eligible for one of two matching formulas depending on an employee's status as a bargaining unit employee or as a non-bargaining unit employee. Bargaining unit employees receive a maximum match of 5% of eligible compensation based upon the following formula: 100% of the employee's tax-deferred contribution on the first 3% of eligible compensation, plus 50% of the next 4% of eligible compensation. Non-bargaining unit employees receive a maximum match of 4% of eligible compensation based upon the following formula: 100% of the employee's tax-deferred contribution on the first 3% of eligible compensation, plus 50% of the next 2% of eligible compensation. The matching contributions under both formulas vest immediately. In addition, certain Cheyenne Light employees are eligible for a Profit Sharing contribution equal to 3.5% to 10% of eligible compensation, depending on age and years of service. Profit sharing contributions vest at 20% per year and are fully vested after completion of five years of service with the Company.

Black Hills Energy employees may elect to invest up to 50% of their eligible base compensation on a pre-tax or after-tax basis. These employees receive a matching contribution of 100% of the employee's annual contribution up to a maximum of 6% of their eligible compensation. These matching contributions vest at 20% per year and are fully vested when the participant has five years of service with the Company.

Employees of the remaining subsidiaries may elect to invest up to 50% of their eligible compensation on a pre-tax basis. These employees receive a matching contribution of 100% of the employee's annual tax-deferred contribution up to a maximum of 3% of eligible compensation. Matching contributions vest at 20% per year and are fully vested when the participant has five years of service with the Company.

Matching contributions for the retirement savings plans totaled $5.7 million for 2009, $3.8 million for 2008 and $2.0 million for 2007. Cheyenne Light profit sharing contributions were $0.1 million for each of 2009, 2008 and 2007.

Effective January 1, 2010, in conjunction with the partial freeze of our defined benefit pension plans, we amended our 401(k) retirement savings plan. This amendment covers all employees with the exception of the bargaining unit employees of Black Hills Power, Cheyenne Light and certain other employees grandfathered under a prior defined benefit plan election. The amendment provides for a matching contribution of 100% of the eligible employee's annual contribution up to a maximum of 6% of eligible compensation. The amendment also provides certain eligible participants an age and service-based additional employer contribution.

Funded Status of Benefit Plans

The funded status of postretirement benefit plans is required to be recognized in the statement of financial position. The funded status for pension plans is measured as the difference between the projected benefit obligation and the fair value of plan assets. The funded status for all other benefit plans is measured as the difference between the accumulated benefit obligation and the fair value of plan assets. A liability is recorded for an amount by which the benefit obligation exceeds the fair value of plan assets or an asset is recorded for any amount by which the fair value of plan assets exceeds the benefit obligation. Except for our regulated utilities, the unrecognized net periodic benefit cost is recorded within Accumulated other comprehensive income (loss), net of tax. For our regulated utilities, we applied accounting standards for regulated operations, and accordingly, the unrecognized net periodic benefit cost was alternatively recorded as a regulatory asset or regulatory liability, net of tax. As of December 31, 2009, the funded status of our Defined Benefit Pension Plan was $79.9 million; the funded status of our Non-Qualified Defined Benefit Retirement Plan was $21.6 million; and the funded status of our Non-Pension Defined Benefit Postretirement Plan was $41.7 million.

Defined Benefit Pension Plan

We have three non-contributory defined benefit pension plans (the Pension Plans). The Black Hills Corporation Pension Plan covers eligible employees of Black Hills Service Company, Black Hills Power, WRDC and BHEP. Benefits are based on years of service and compensation levels during the highest five consecutive years of the last ten years of service. The Cheyenne Light Pension Plan covers eligible employees of Cheyenne Light. Benefits for the bargaining unit employees of Cheyenne Light are based on years of service and compensation levels during the highest three consecutive 12-month periods of service, reduced by the vested benefits under the predecessor plans, if any. Benefits for the non-bargaining unit employees of Cheyenne Light are based on annual credits for years of service plus investment credits. The Black Hills Energy Pension Plan covers eligible employees of our utility subsidiaries doing business as Black Hills Energy. Benefits are based on years of service and compensation levels during the highest four consecutive years of the last ten years of service.

In July 2009, the Board of Directors approved a partial freeze to the Black Hills Corporation Pension Plan (with the exception of bargaining unit participants), the Black Hills Energy Pension Plan and the Cheyenne Light Pension Plan (with the exception of bargaining unit participants) which is effective January 1, 2010. The Black Hills Corporation freeze eliminates new non-bargaining unit employees from participation in the plan, and freezes the benefits of current non-bargaining unit participants except for the following group: those non-bargaining unit participants who are both 1) age 45 or older as of December 31, 2009 and have 10 years or more of credited service as of January 1, 2010; and 2) elect to continue to accrue additional benefits under the pension plan and consequently forego the additional age- and points-based employer contribution under the Company's 401(k) retirement savings plan. The Black Hills Energy Plan freeze eliminates new employees from participation in the Plan, and freezes the benefits of current participants except for the following group: those participants who are both 1) age 45 or older as of December 31, 2009 and have 10 years or more of credited service as of January 1, 2010; and 2) elect to continue to accrue additional benefits under the pension plan and consequently forego the additional age- and points-based employer contribution under the Company's 401(k) retirement savings plan. The Cheyenne Light Pension Plan freeze eliminates new non-bargaining unit employees from participation in the plan and freezes the benefits of existing non-bargaining unit participants. The assets and obligations for the Black Hills Corporation Plan and the Black Hills Energy Pension Plan were revalued July 31, 2009 in conjunction with the freeze of these plans and we recognized a pre-tax curtailment expense of approximately $0.3 million in the third quarter of 2009. The valuation of the Cheyenne Light Pension Plan at December 31, 2009, resulted in recognition of a pre-tax curtailment expense of less than $0.1 million in the fourth quarter of 2009.

Our funding policy is in accordance with the federal government's funding requirements. The Pension Plans' assets are held in trust and consist primarily of equity and fixed income investments. We use a December 31 measurement date for the Pension Plans.

The Investment Policy for the Pension Plans is to seek to achieve the following long-term objectives: 1) a rate of return in excess of the annualized inflation rate based on a five year moving average; 2) a rate of return that meets or exceeds the assumed actuarial rate of return as stated in the Plan's actuarial report; 3) a rate of return on investments, net of expenses, that is equal to or exceeds various benchmark rates on a moving three year average, and 4) maintenance of sufficient income and liquidity to pay monthly retirement benefits. The policy strategy seeks to prudently invest in a diversified portfolio of predominately equity and fixed income assets. The policy contains certain prohibitions on transactions in separately managed portfolios in which the Pension Plans may invest, including prohibitions on short sales.

The Pension Plans' expected long-term rate of return on assets assumptions are based upon the weighted-average expected long-term rate of return for each individual asset class. The asset class weighting is determined using the target allocation for each class in the Plan portfolio. The expected long-term rate of return for each asset class is determined primarily from adjusted long-term historical returns for the asset class. It is anticipated that long-term future returns will not achieve historical results.

The expected long-term rate of return for equity investments was 9.5% for the 2009 and 2008 plan years. For determining the expected long-term rate of return for equity assets, we reviewed annual 20-, 30-, 40-, and 50-year returns on the S&P 500 Index, which were, at December 31, 2009, 8.1%, 11.1%, 9.7% and 9.3%, respectively. Fund management fees were estimated to be 0.18% for S&P 500 Index assets and 0.45% for other assets. The expected long-term rate of return for real estate investments was 7.0%; the return was based on five-year forward-looking return projections from our investment manager for the NCREIF index. The expected long-term rate of return on fixed income investments was 6.0%; the return was based upon historical returns on 10-year treasury bonds of 6.9% from 1962 to 2009, and adjusted for recent declines in interest rates. The expected long-term rate of return on cash investments was estimated to be 1.0%, which was based upon current one-year LIBOR rates.

Plan Assets

The percentages of total plan asset fair value by investment category for our Pension Plans at December 31, were as follows:

	2009		2008	
Equity	65	%	60	%
Real estate	3		5	
Fixed income	28		33	
Cash	4		2	
Total	100	%	100	%

Cash Flows

We made a contribution of $0.4 million to the Black Hills Corporation Pension Plan in 2009 and expect no contributions to the Plan in fiscal year 2010. We made a $1.5 million contribution to the Cheyenne Light Pension Plan in 2009 and expect to make a $0.7 million contribution during fiscal year 2010. We made a contribution of $15.0 million to the Black Hills Energy Pension Plan in 2009 and expect no contributions in fiscal year 2010.

Supplemental Non-qualified Defined Benefit Retirement Plans

We have various supplemental retirement plans for key executives of the Company. The plans are non-qualified defined benefit plans. We use a December 31 measurement date for the plans. Effective January 1, 2010, we eliminated a non-qualified pension plan in which some of our officers participated due to the partial freeze of our qualified pension plans. We also amended the NQDC, which was adopted in 1999. The NQDC is a non-qualified deferred compensation plan that provides executives with an opportunity to elect to defer compensation and receive benefits without reference to the limitations on contributions in the Black Hills Corporation Retirement Savings Plan or those imposed by the Internal Revenue Code of 1986, as amended. The amended NQDC provides for non-elective non-qualified restoration benefits to certain officers who are not eligible to continue accruing benefits under the Defined Benefit Pension Plans and associated non-qualified pension restoration plans.

All contributions to the non-qualified plans are subject to a graded vesting schedule at 20% per year over five years with vesting credit beginning with service in the plan on and after January 1, 2010.

Plan Assets

The plans have no assets. We fund on a cash basis as benefits are paid.

Estimated Cash Flows

The estimated employer contribution is expected to be $0.9 million in 2010. Contributions are expected to be made in the form of benefit payments.

Non-pension Defined Benefit Postretirement Plan

We sponsor three retiree healthcare plans (the Plans): the Black Hills Corporation Postretirement Healthcare Plan, the Healthcare Plan for Retirees of Cheyenne Light, and the Black Hills Energy Postretirement Healthcare Plan. Employees who participate in the Black Hills Corporation Postretirement Healthcare Plan and who retire from the Company on or after attaining age 55 after completing at least five years of service with the Company are entitled to postretirement healthcare benefits. Employees who participate in the Healthcare Plan for Retirees of Cheyenne Light and who retire from Cheyenne Light on or after attaining age 55 and after completion of a number of consecutive years of service, which when added to the employee's age totals 90, are entitled to postretirement healthcare benefits. Employees who are participants in the Black Hills Utility Holdings Postretirement Healthcare Plan and who retire from the Company on or after attaining age 55 after completing at least five years of service with the Company are entitled to postretirement healthcare benefits. In July 2009, the Board of Directors also approved amendments to the BHC Retiree Healthcare Plan and the Black Hills Utility Holdings Plan which changed the structure of the Plans for non-union employees and participating union employees to an RMSA and expanded eligibility of plan participants, effective January 1, 2010.

The benefits for all of the plans are subject to premiums, deductibles, co-payment provisions and other limitations. We may amend or change the plans periodically. We are not pre-funding the Black Hills Corporation or Cheyenne Light retiree healthcare plans. A portion of Black Hills Energy's Postretirement Healthcare Plan is pre-funded via VEBAs, and the assets are held in trust. We use a December 31 measurement date for the Plans.

It has been determined that the post-65 retiree prescription drug plans are actuarially equivalent and qualify for the Medicare Part D subsidy. The effect of the Medicare Part D subsidy on the accumulated postretirement benefit obligation for the 2009 fiscal year was an actuarial gain of approximately $4.3 million. The effect on 2009 net periodic postretirement benefit cost was a decrease of approximately $0.5 million.

Plan Assets

The Black Hills Corporation and Cheyenne Light retiree healthcare plans have no assets. We fund on a cash basis as benefits are paid. The Black Hills Energy Plan provides for partial pre-funding via VEBAs. Assets of $4.7 million related to this pre-funding are held in trust and are for the benefit of the union and non-union employees of Black Hills Energy located in the states of Kansas and Iowa. We do not pre-fund the Postretirement Healthcare Plan for those employees outside Kansas and Iowa.

Estimated Cash Flows

The estimated employer contributions are expected to be $4.3 million in 2010. Contributions are expected to be made in the form of benefit payments.

Fair Value Measurements

Accounting standards for Compensation – Retirement Benefits provides a single definition of fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date and also requires disclosures and establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The fair value hierarchy ranks the quality and reliability of the information used to determine fair values giving the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements). The pension plans and VEBA are able to classify fair value balances based on the observability of inputs.

Financial assets and liabilities carried at fair value are classified and disclosed in one of the following three categories:

Level 1 - Unadjusted quoted prices available in active markets that are accessible at the measurement date for identical unrestricted assets or liabilities.

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

Level 3 - Pricing inputs include significant inputs that are generally less observable from objective sources.

As required by accounting standards for Compensation – Retirement Benefits, assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect their placement within the fair value hierarchy levels. The following tables set forth, by level within the fair value hierarchy, the assets that were accounted for at fair value on a recurring basis as of December 31, 2009 and 2008:

Defined Benefit Pension Plan	At Fair Value as of December 31, 2009			
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total
		(in thousands)		
Registered Investment Companies	$39,446	$-	$-	$39,446
103-12 Investment Entities	-	10,611	-	10,611
Common Collective Trust	-	120,602	5,844	126,446
Total investments measured at fair value	$39,446	$131,213	$5,844	$176,503

Defined Benefit Pension Plan	At Fair Value as of December 31, 2008			
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total
		(in thousands)		
Registered Investment Companies	$30,042	$-	$-	$30,042
103-12 Investment Entities	-	8,700	-	8,700
Common Collective Trust	-	89,857	8,300	98,157
Total investments measured at fair value	$30,042	$98,557	$8,300	$136,899

Non-pension Defined Benefit Postretirement Plan	At Fair Value as of December 31, 2009			
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total
		(in thousands)		
Common Collective Trust	$-	$4,717	$-	$4,717
Total investments measured at fair value	$-	$4,717	$-	$4,717

Non-pension Defined Benefit Postretirement Plan	At Fair Value as of December 31, 2008			
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total
		(in thousands)		
Common Collective Trust	$-	$4,950	$-	$4,950
Total investments measured at fair value	$-	$4,950	$-	$4,950

The following table sets forth a summary of changes in the fair value of the Defined Benefit Pension Plan's level 3 assets for the period ended December 31 (in thousands):

	2009	2008
Balance, beginning of period	$8,300	$-
Issuances, repayments, transfers and settlements, net	(2,456)	8,300
Balance, end of period	$5,844	$8,300

The following tables provide a reconciliation of the employee benefit plan obligations, fair value of assets and amounts recognized in the statement of financial position for 2009 and 2008, components of the net periodic expense for the years ended 2009, 2008 and 2007 and elements of accumulated other comprehensive income for 2009 and 2008 (in thousands):

Benefit Obligations

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2009	2008	2009	2008	2009	2008
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$242,545	$78,983	$22,862	$19,943	$36,940	$13,726
Sponsorship transfer(a)	-	132,236	-	1,530	-	20,904
Service cost	7,587	5,474	469	559	1,061	847
Interest cost	14,715	10,360	1,376	1,588	2,202	1,705
Actuarial (gain) loss	9,200	21,452	(1,150)	1,123	12,830	1,710
Amendments	258	20	22	-	(3,732)	(768)
Benefits paid	(9,002)	(5,980)	(891)	(1,881)	(5,113)	(2,369)
Plan curtailment reduction	(8,081)	-	(1,077)	-	-	-
Medicare Part D accrued	-	-	-	-	555	81
Equitable asset	(822)	-	-	-	-	-
Plan participant's contributions	-	-	-	-	1,653	1,104
Net increase (decrease)	13,855	163,562	(1,251)	2,919	9,456	23,214
Projected benefit obligation at end of year	$256,400	$242,545	$21,611	$22,862	$46,396	$36,940

(a) The sponsorship transfer presents the amount recorded from the change in sponsorship from Aquila to the Company from the Aquila Transaction.

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A reconciliation of the fair value of Plan assets (as of the December 31 measurement date) is as follows (in thousands):

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2009	2008	2009	2008	2009	2008
Beginning market value of plan assets	$136,899	$75,107	$-	$-	$4,950	$-
Sponsorship transfer	-	112,672	-	-	-	4,525
Investment income	33,024	(45,400)	-	-	336	357
Contributions	16,945	500	-	-	2,608	1,234
Benefits paid	(9,002)	(5,980)	-	-	(3,177)	(1,166)
Plan administrative expenses	(496)	-	-	-	-	-
Equitable asset	(867)	-	-	-	-	-
Ending market value of plan assets	$176,503	$136,899	$-	$-	$4,717	$4,950

Amounts recognized in the statement of financial position consist of (in thousands):

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2009	2008	2009	2008	2009	2008
Regulatory asset	$53,768	$70,277	$-	$-	$8,660	$210
Current liability	$-	$-	$891	$789	$3,124	$1,948
Non-current asset	$-	$-	$-	$-	$-	$-
Non-current liability	$79,897	$105,646	$20,719	$22,073	$38,554	$30,041
Regulatory liability	$-	$-	$-	$-	$-	$1,513

Accumulated Benefit Obligation

(in thousands)	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2009	2008	2009	2008	2009	2008
Accumulated benefit obligation - Black Hills Corporation	$77,948	$68,781	$17,205	$21,964	$13,108	$11,547
Accumulated benefit obligation - Black Hills Energy	$142,012	$131,936	$445	$609	$26,329	$21,479
Accumulated benefit obligation - Cheyenne Light	$3,849	$3,212	$-	$-	$6,959	$3,914

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Components of Net Periodic Expense

(in thousands)	Defined Benefit Pension Plans			Supplemental Non-qualified Defined Benefit Retirement Plans			Non-pension Defined Benefit Postretirement Plans		
	2009	2008	2007	2009	2008	2007	2009	2008	2007
Service cost	$ 7,587	$ 4,720	$ 2,745	$ 469	$ 447	$ 410	$ 1,060	$ 721	$ 539
Interest cost	14,715	9,130	4,517	1,376	1,277	1,157	2,202	1,488	828
Expected return on assets	(14,281)	(10,627)	(5,493)	-	-	-	(226)	(97)	-
Amortization of prior service cost	127	163	153	1	10	13	(23)	-	-
Amortization of transition obligation	-	-	-	-	-	-	60	59	60
Recognized net actuarial loss (gain)	2,720	-	507	589	569	713	(27)	(81)	(16)
Curtailment expense	322	-	-	-	-	-	-	-	-
Net periodic expense	$ 11,190	$ 3,386	$ 2,429	$ 2,435	$ 2,303	$ 2,293	$ 3,046	$ 2,090	$ 1,411

Accumulated Other Comprehensive Income

In accordance with accounting standards for defined benefit plans, amounts included in accumulated other comprehensive income (loss), after-tax, that have not yet been recognized as components of net periodic benefit cost at December 31 are as follows (in thousands):

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2009	2008	2009	2008	2009	2008
Net (gain) loss	$6,436	$18,176	$3,429	$(5,235)	$2,131	$9
Prior service cost	144	314	16	(3)	(2,510)	-
Transition obligation	-	-	-	-	-	(21)
Total accumulated other comprehensive income	$6,580	$18,490	$3,445	$(5,238)	$(379)	$(12)

The amounts in accumulated other comprehensive income, regulatory assets or regulatory liabilities, after-tax, expected to be recognized as a component of net periodic benefit cost during calendar year 2010 are as follows (in thousands):

	Defined Benefit Pension	Supplemental Nonqualified Defined	Non-pension Defined Benefit

	Plans	Benefit Retirement Plans	Postretirement Plans
Net loss	$2,032	$ 185	$ 413
Prior service cost	64	2	(201)
Transition obligation	-	-	-
Total net periodic benefit cost expected to be recognized during calendar year 2010	$2,096	$ 187	$ 212

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Assumptions

	Defined Benefit Pension Plans			Supplemental Nonqualified Defined Benefit Retirement Plans			Non-pension Defined Benefit Postretirement Plans		
Weighted-average assumptions used to determine benefit obligations:	2009	2008	2007	2009	2008	2007	2009	2008	2007
Discount rate	6.03 %	6.20 %	6.35 %	5.58 %	6.20 %	6.35 %	5.68 %	6.10 %	6.35 %
Rate of increase in compensation levels	4.20 %	4.25 %	4.34 %	5.00 %	5.00 %	5.00 %	N/A	N/A	N/A
Weighted-average assumptions used to determine net periodic benefit cost for plan year:	2009	2008	2007	2009	2008	2007	2009	2008	2007
Discount rate:									
Black Hills Corporation	6.25 %	6.35 %	5.95 %	6.20 %	6.35 %	5.95 %	6.10 %	6.35 %	5.95 %
Black Hills Energy	6.25 %	7.00 %	N/A	5.00 %	5.00 %	N/A	6.10 %	6.75 %	N/A
Expected long-term rate of return on assets*	8.50 %	8.50 %	8.50 %	N/A	N/A	N/A	5.00 %	5.00 %	N/A
Rate of increase in compensation levels	4.20 %	4.34 %	4.31 %	5.00 %	N/A	5.00 %	N/A	N/A	N/A

*The expected rate of return on plan assets changed to 8% for the calculation of the 2010 net periodic pension cost.

The healthcare trend rate assumption for 2009 fiscal year benefit obligation determination and 2010 fiscal year expense is a 10% increase for 2009 grading down until a 4.5% ultimate trend rate is reached in fiscal year 2027. The healthcare cost trend rate assumption for the 2008 fiscal year benefit obligation determination and 2009 fiscal year expense was a 9% increase for 2009 grading down 1% per year until a 5% ultimate trend rate is reached in fiscal year 2013.

The healthcare cost trend rate assumption has a significant effect on the amounts reported. A 1% increase in the healthcare cost trend assumption would increase the service and interest cost $0.4 million or 12% and the accumulated periodic postretirement benefit obligation $3.1 million or 7%. A 1% decrease would reduce the service and interest cost by $0.3 million or 8.0%, and the accumulated periodic postretirement benefit obligation $2.5 million or 5%.

The following benefit payments, which reflect future service, are expected to be paid (in thousands):

	Non-pension Defined Benefit Postretirement Plans

	Defined Benefit Pension Plans	Supplemental Nonqualified Defined Benefit Retirement Plan	Expected Gross Benefit Payments	Expected Medicare Part D Drug Benefit Subsidy	Expected Net Benefit Payments
2010	$10,484	$ 891	$4,329	$(505)	$3,824
2011	11,262	920	4,602	(559)	4,043
2012	11,991	927	4,679	(620)	4,059
2013	12,968	941	4,564	(681)	3,883
2014	14,038	1,090	4,478	(743)	3,735
2015-2019	87,049	7,003	19,860	(1,685)	18,175

(19) COMMITMENTS AND CONTINGENCIES

Partial Sale of Wygen I to MEAN

During August 2008, we entered into a definitive agreement to sell a 23.5% ownership interest in the Wygen I plant to MEAN. The sale was completed in January 2009 for a price of $51.0 million, which was based on the then-current replacement cost for the coal-fired plant. We realized an after-tax gain of $16.9 million on the sale, and our property, plant and equipment was reduced by $25.0 million. We retain responsibility for operations of the plant, and at closing entered into a site lease, and operating agreements with MEAN for coal supply and operations. In addition, we terminated a 10-year PPA requiring MEAN to purchase 20 MW of power annually from Wygen I.

Partial Sale of Wygen III to MDU

On April 9, 2009, Black Hills Power sold to MDU a 25% ownership interest in its Wygen III generation facility currently under construction. At closing, MDU made a payment to us for its 25% share of the costs to date on the ongoing construction of the facility. Proceeds of $32.8 million were received of which $30.2 million was used to pay down a portion of the Acquisition Facility. MDU will continue to reimburse Black Hills Power for its 25% of the total costs paid to complete the project. In conjunction with the sales transaction, we also modified a 2004 PPA between Black Hills Power and MDU. The PPA with MDU now provides that once in commercial operations, the first 25 MW of MDU's required 74 MW will be supplied from its 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.

Power Purchase and Transmission Services Agreements

Through our subsidiaries, we have the following significant long-term power purchase contracts with non-affiliated third-parties:

- We have a PPA with PacifiCorp expiring in 2023, for the purchase of 50 MW of electric capacity and energy from PacifiCorp's system. The price paid for the capacity and energy is based on the operating costs of one of PacifiCorp's coal-fired electric generating plants. Costs incurred under this agreement were $11.8 million in 2009, $11.6 million in 2008 and $10.9 million in 2007.

- Colorado Electric has a PPA with PSCo, expiring in 2011, for 280 MW of capacity and energy in 2009, increasing 10 MW per year to 300 MW in 2011. Pricing for the PPA is based on annual contracted capacity and an 85% load factor at current FERC approved rates.

- We have a firm point-to-point transmission service agreement with PacifiCorp that expires in December 2023. The agreement provides 50 MW of capacity and energy to be transmitted annually by PacifiCorp through 2023. Costs incurred under this agreement were $1.2 million in 2009, $1.2 million in 2008 and $1.2 million in 2007.

- Cheyenne Light's 20-year PPA with Duke Energy's Happy Jack wind site, expiring in September 2028, provides up to 29.4 MW of wind energy from Happy Jack to Cheyenne Light. Under a separate intercompany agreement, Cheyenne Light sells 50% of the facility output to Black Hills Power.

- Cheyenne Light entered into a 20-year PPA with Duke Energy's Silver Sage wind site for 30 MW of energy. Commercial operations commenced in October 2009. Under a separate intercompany agreement, Cheyenne Light has agreed to sell 20 MW of energy from Silver Sage to Black Hills Power.

Our Gas Utilities also purchase natural gas, including transportation capacity to meet customers' needs under short-term and long-term purchase contracts. These contracts extend to 2017.

On September 29, 2009, FERC approved an extension of a PPA between our subsidiaries, Black Hills Wyoming and Cheyenne Light. The PPA for 60 MW of capacity and energy from Black Hills Wyoming's Wygen I generating facility, which was scheduled to expire in 2013, has been extended through December 31, 2022. The agreement includes an option for Cheyenne Light to purchase Black Hills Wyoming's ownership in the Wygen I facility during years one to seven of the term of the extended agreement. The purchase price related to the option is $2.55 million per MW which is the equivalent per MW of the estimated price of new construction of the Wygen III plant. This option purchase price is reduced annually by an amount equal to annual depreciation assuming a facility life of 35 years.

Long-Term Power Sales Agreements

Through our subsidiaries, we have the following significant long-term power sales contracts with non-affiliated third-parties:

- An agreement under which we supply up to 74 MW of capacity and energy to MDU for the Sheridan, Wyoming electric service territory through the end of 2016. The sales to MDU have been integrated into Black Hills Power's control area and are considered part of our firm native load. In accordance with the terms of this agreement, MDU exercised an option to participate in the ownership of the Wygen III plant that is currently being constructed. Under an agreement entered into in April 2009, MDU purchased a 25% undivided interest in the Wygen III plant. We retain responsibility for operations of the facility with a life-of-plant lease and agreements with MDU for operations and coal supply. In conjunction with the sales transaction, we also modified the 2004 PPA under which Black Hills Power supplied MDU with 74 MW of capacity and energy through 2016. The agreement now provides that once in commercial operations, the first 25 MW of the required 74 MW will be supplied by MDU's ownership interest in Wygen III. During periods of reduced production at Wygen III, or during periods when Wygen III is offline, we will provide MDU with its first 25 MW from our other generation facilities or from system purchases;

- An 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; and

- 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.

- In March 2009, our 10-year power sales contract between MEAN and Black Hills Power that originally would have expired in 2013 was re-negotiated and extended until 2023. Under the new contract, MEAN will purchase 20 MW of unit-contingent capacity from the 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 plants 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.

Reclamation Liability

Under its mining permit, WRDC is required to reclaim all land where it has mined coal reserves. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land with an equivalent amount added to the asset costs. The asset is depreciated over the appropriate time period and the liability is accreted over time using an interest method of allocation. Approximately $1.1 million, $0.6 million and $0.3 million was charged to accretion expense for the years ended December 31, 2009, 2008 and 2007, respectively. Approximately $2.0 million, $0.6 million and $0.5 million was charged to depreciation expense for the years ended December 31, 2009, 2008 and 2007, respectively. Accrued reclamation costs included in Other deferred credits and other liabilities on the accompanying Consolidated Balance Sheets were approximately $15.3 million and $17.7 million at December 31, 2009 and 2008, respectively.

Legal Proceedings

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in the consolidated financial statements are adequate in light of the probable and estimable contingencies. However, there can be no assurance that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims and other matters discussed, and to comply with applicable laws and regulations, will not exceed the amounts reflected in the consolidated financial statements. As such, costs, if any, that may be incurred in excess of those amounts provided as of December 31, 2009, cannot be reasonably determined and could have a material adverse effect on the results of operations or financial position.

FERC Compliance Investigation

During 2007, following an internal review of natural gas marketing activities conducted within the Energy Marketing segment, 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 the FERC 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 by Enserco Energy Inc., did not have a material impact upon our overall consolidated results of operations and cash flows.

(20) GUARANTEES

We have entered into various agreements providing financial or performance assurance to third parties on behalf of certain of our subsidiaries. The agreements include guarantees of debt obligations, contractual performance obligations and indemnification for reclamation and surety bonds.

As of December 31, 2009, we had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2009	Year Expiring
Guarantee obligations of Enserco under an agency agreement	$7,000	2010
Guarantees of payment obligations arising from commodity-related physical and financial transactions by Black Hills Utility Holdings	70,000	Ongoing
Guarantees for payment obligations arising from purchase contracts for four gas turbines for Black Hills Colorado IPP	62,090	2011
Guarantees for payment obligations arising from purchase contracts for two gas turbines for Colorado Electric	42,742	2010
Indemnification for subsidiary reclamation/surety bonds	15,532	Ongoing
	$197,364	

We have guaranteed up to $7.0 million of the obligations of Enserco under an agency agreement whereby Enserco provides services to structure up to $143.3 million United States dollars (converted from $150.0 million Canadian dollars as of December 31, 2009) of certain transactions involving the buying, selling, transportation and storage of natural gas on behalf of another energy company. The guarantee expires in July 2010.

We have guaranteed up to $25.0 million of the obligations of Black Hills Utility Holdings for payment obligations arising from commodity-related physical and financial transactions with BP Energy Company and/or BP Canada Energy Marketing Corp. These commodity transactions secure natural gas supply for our regulated gas utilities. The guarantee is a continuing guarantee that may be terminated upon 30 days written notice to the counterparty.

We have guaranteed up to $20.0 million of the obligations of Black Hills Utility Holdings for payment obligations arising from commodity-related physical and financial transactions with Northern Natural Gas Company. These commodity transactions secure natural gas supply for our regulated gas utilities. The guarantee is a continuing guarantee that may be terminated upon 30 days written notice to the counterparty.

We have guaranteed up to $25.0 million of the obligations of Black Hills Utility Holdings for payment obligations arising from commodity-related physical and financial transactions with PSCo. These commodity transactions secure natural gas supply for our regulated gas utilities. The guarantee is a continuing guarantee that may be terminated upon 30 days written notice to the counterparty.

We have issued two guarantees totaling $42.7 million to GE for payment obligations arising from a contract to purchase two LMS100 natural gas turbine generators by Colorado Electric, which will be used in meeting a portion of the capacity and energy needs of our Colorado Electric customers. These are continuing guarantees which terminate upon payment in full of the purchase price to GE. Payments are scheduled based upon estimated construction milestone dates with the final payment due October 27, 2010.

We have issued four guarantees totaling $62.1 million to GE for payment obligations arising from contracts to purchase four LM6000 gas turbines for Black Hills Colorado IPP. These are continuous guarantees which terminate upon payment in full of the purchase price to GE. Payments are scheduled based upon estimated construction milestone dates with the final payment due February 8, 2011.

In addition, at December 31, 2009, we had guarantees in place totaling approximately $15.5 million for reclamation and surety bonds for our subsidiaries. The guarantees were entered into in the normal course of business. To the extent liabilities are incurred as a result of activities covered by the surety bonds, such liabilities are included in our Consolidated Balance Sheets.

(21) OIL AND GAS RESERVES AND RELATED FINANCIAL DATA (Unaudited)

BHEP has operating and non-operating interests in 1,314 developed oil and gas wells in ten states and holds leases on approximately 406,200 net acres.

Costs Incurred

Following is a summary of costs incurred in oil and gas property acquisition, exploration and development during the years ended December 31 (in thousands):

	2009	2008	2007
Acquisition of properties:			
Proved	$-	$15,710	$-
Unproved	3,443	1,290	-
Exploration costs	5,962	13,703	7,250
Development costs	10,133	49,441	62,104
Asset retirement obligations incurred	623	5,029	1,934
	$20,161	$85,173	$71,288

Reserves

The following table summarizes BHEP's quantities of proved developed and undeveloped oil and natural gas reserves, estimated using SEC-defined product prices, as of December 31, 2009, 2008 and 2007, and a reconciliation of the changes between these dates. These estimates are based on reserve reports by Cawley, Gillespie & Associates, Inc., an independent engineering company. Such reserve estimates are inherently imprecise and may be subject to revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. The current estimate takes into account 2009 production of approximately 11.9 Bcfe, additions from extensions, discoveries and acquisitions of 3.5 Bcfe and negative revisions to previous estimates of 57.8 Bcfe, including approximately 54.9 Bcfe due to lower crude oil and natural gas prices. The reserves below as of December 31, 2009 incorporate SEC reserve reporting changes that apply to this Annual Report on Form 10-K.

	2009		2008		2007	
	Oil	Gas	Oil	Gas	Oil	Gas
	(in thousands of Bbls of oil and MMcf of gas)					
Proved developed and undeveloped reserves:						
Balance at beginning of year	5,185	154,432	5,807	172,964	5,723	164,754
Production	(366)	(9,710)	(387)	(10,704)	(409)	(11,697)
Additions - acquisitions	-	-	2	3,352	-	-
Additions - extensions and discoveries	152	2,560	438	4,037	373	21,318
Revisions to previous estimates	303	(59,622)	(675)	(15,217)	120	(1,411)
Balance at end of year	5,274	87,660	5,185	154,432	5,807	172,964
Proved developed reserves at end of year included above	4,274	74,911	4,429	88,701	5,095	92,522
NYMEX prices	$61.18 *	$3.87 *	$44.60	$5.71	$95.98	$6.80
Well-head reserve prices	$53.59	$2.52	$32.74	$4.44	$83.23	$5.88

*On December 31, 2008, the SEC issued final rules amending its oil and gas reserve reporting requirements effective for years ended on or after December 31, 2009. The final rule changes the use of prices at the end of each reporting period to prices that are an average of the first day of the month for the preceding twelve months held constant for the life of production. Previously, the rule required the use of the spot price on the last day of the reporting period, held constant for the life of production.

Reserve additions totaled 3.5 Bcfe, replacing 29% of production. The addition is a result of the development drilling in North Dakota, Montana and New Mexico. Drilling in North Dakota (Bakken Shale) and New Mexico (San Jose) accounted for 3.3 Bcfe of the additions. North Dakota drilling may resume in 2010. Capital spending in 2009 was reduced significantly relative to prior years in response to low product prices. Future capital spending rates are anticipated to increase with improved product prices, resulting in higher anticipated production replacement ratios.

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The overall downward revision to reserves totaled 57.8 Bcfe with 95% of this revision, or 54.9 Bcfe, due to lower crude oil and natural gas prices. A reduction in lease operating costs on our operated properties resulted in a positive revision of 2 Bcf. Performance related revisions were a negative 4.9 Bcfe (approximately 4.1% of year-end 2009 reserve total). We experienced downward revisions in the San Juan basin by eliminating PUD locations and adjusting existing wells after removing well site compressors that were uneconomic at prevailing prices. Additionally, there were minor adjustments downward in Colorado, Wyoming, Montana and New Mexico. Offsetting some of these downward revisions were better than expected results from our late 2008 drilling program in North Dakota (Bakken Shale).

The SEC adopted new guidelines for reporting reserves in 2009 which amended existing reporting requirements as follows:

- The pricing used to determine reserves must be an average of the first-of-the-month prices over twelve-months instead of a one-day price at the end of the reporting period. This change had a negative impact on our 2009 reserves as follows:

	Oil $/BBL	Gas $/Mcf
Currently required twelve-month 2009 average pricing	$53.69	$2.52
Previously required one-day end-of-period December 31, 2009 pricing (non-GAAP)	$69.98	$4.92

	Oil (Mbbl)	Gas (MMcf)	PV10 (in thousands)
Currently required twelve-month 2009 average pricing	5,274	87,660	$134,322
Previously required one-day end-of-period December 31, 2009 pricing (non-GAAP)	5,407	147,876	$275,946

- The SEC established a new definition of "reliable technology" which broadens the technology that a company may use to establish reserves and categories. The new definition permits the use of any reliable technology to establish reserve volumes in addition to those established by production and flow test data. This new definition eliminates previous restrictions limiting allowable PUDs to be booked only one location away from a producing well. We elected to continue with our existing methodology for 2009.

- Companies are now permitted but not required to disclose probable and possible reserves. We have elected not to report on these additional reserve categories for 2009.

- Companies are required to include a narrative disclosure of the total quantity of PUDs at year end, any material changes in PUDs during the year, and investment and progress made in converting the PUDs during the year commencing prospectively from 2009. We have 107 gross PUD locations as of December 31, 2009 located in five states. Consistent with the new SEC guidance, these PUD locations will be monitored and reported each year until they are drilled or revised.

Capitalized Costs

Following is information concerning capitalized costs for the years ended December 31, (in thousands):

	2009	2008	2007
Unproved oil and gas properties	$29,351	$31,507	$37,459
Proved oil and gas properties	582,276	561,779	475,061
	611,627	593,286	512,520
Accumulated depreciation, depletion and amortization and valuation allowances	(335,605)	(267,893)	(141,780)
Net capitalized costs	$276,022	$325,393	$370,740

Results of Operations

Following is a summary of results of operations for producing activities for the years ended December 31, (in thousands):

	2009	2008	2007
Revenues			
Sales	$70,214	$106,019	$101,286
Production costs	24,192	34,198	28,824
Depreciation, depletion & amortization and valuation provisions*	69,329	126,980	31,212
	93,521	161,178	60,036
	(23,307)	(55,159)	41,250
Income tax benefit (expense)	8,041	19,306	(14,273)
Results of operations from producing activities (excluding general and administrative costs and interest costs)	$(15,266)	$(35,853)	$26,977

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*Includes pre-tax ceiling test impairment charges of $43.3 million and $91.8 million in 2009 and 2008, respectively.

Standardized Measure of Discounted Future Net Cash Flows

Following is a summary of the standardized measure of discounted future net cash flows and changes relating to proved oil and gas reserves for the years ended December 31, (in thousands):

	2009	2008	2007
Future cash inflows	$519,867	$875,926	$1,544,175
Future production costs	(207,783)	(309,169)	(438,314)
Future development costs	(34,961)	(130,632)	(140,118)
Future income tax expense	(51,287)	(100,791)	(284,678)
Future net cash flows	225,836	335,334	681,065
10% annual discount for estimated timing of cash flows	(96,728)	(156,108)	(358,167)
Standardized measure of discounted future net cash flows	$129,108	$179,226	$322,898

The following are the principal sources of change in the standardized measure of discounted future net cash flows during the years ended December 31, (in thousands):

	2009	2008	2007
Standardized measure - beginning of year	$179,226	$322,898	$267,525
Sales and transfers of oil and gas produced, net of production costs	(26,836)	(78,342)	(63,659)
Net changes in prices and production costs	(40,786)	(191,784)	107,920
Extensions, discoveries and improved recovery, less related costs	3,324	7,961	34,771
Net changes in future development costs	87,620	26,062	45,127
Revisions of previous quantity estimates, changes in production rates, changes in timing and other	(104,556)	(41,861)	(71,685)
Accretion of discount	19,596	42,485	33,852
Net change in income taxes	11,520	85,218	(30,953)
Purchases of reserves	-	6,592	-
Sales of reserves	-	(3)	-
Standardized measure - end of year	$129,108	$179,226	$322,898

Changes in the standardized measure from "revisions of previous quantity estimates, changes in production rates, changes in timing and other," are driven by reserve revisions, modifications of production profiles and timing of future development. For all years presented, we had minimal net reserve revisions to prior estimates. Production forecast modifications are generally made at the well level each year through the reserve review process. These production profile modifications are based on incorporation of the most recent production information and applicable technical studies. Timing of future development investments are reviewed each year and are often modified in response to current market conditions for items such as permitting, service availability, etc.

(22) DISCONTINUED OPERATIONS

Results of operations and the related charges for discontinued operations have been classified as Income (loss) from discontinued operations, net of income taxes in the accompanying Consolidated Statements of Income. Assets and liabilities of the discontinued operations have been reclassified and reflected on the accompanying Consolidated Balance Sheets as Assets of discontinued operations and Liabilities of discontinued operations. For comparative purposes, all prior periods presented have been restated to reflect the reclassifications on a consistent basis.

IPP Transaction

On April 29, 2008, we entered into a definitive agreement to sell seven IPP plants to affiliates of Hastings and IIF for $840 million, subject to certain working capital adjustments. The transaction was completed July 11, 2008. Under the agreement, we received net pre-tax cash proceeds of $756 million, including the effects of estimated working capital adjustments and other costs and our required payoff of approximately $67.5 million of associated project level debt. The after-tax gain recorded on the asset sale was approximately $142.2 million of which $2.4 million was recorded in 2009 and $139.7 million was recorded in 2008 in discontinued operations. For business segment reporting purposes, results were previously included in the Power Generation segment.

Revenues and net income from the discontinued operations associated with the divested IPP plants at December 31 were as follows (in thousands):

	2009	2008 *	2007
Operating revenues	$-	$59,572	$121,076
Pre-tax income from discontinued operations	1,190	27,140	38,057
Gain on sale	-	233,599	-
Income tax benefit (expense)	1,249	(103,758)	(13,214)
Net income from discontinued operations	$2,439	$156,981	$24,843

* In accordance with GAAP, during the second quarter of 2008, the Company ceased recording depreciation and amortization expense on the IPP facilities.

The indirect corporate costs and inter-segment interest expense related to the IPP assets sold and not reclassified to discontinued operations were $0 million, $11.8 million and $19.0 million for the years ended 2009, 2008 and 2007, respectively. These allocated costs remain in the Power Generation segment.

Interest expense included within the operations of the discontinued entities was recorded pursuant to accounting standards for discontinued operations and included interest expense on debt which was required to be repaid as a result of the sale transaction. Interest expense was allocated to discontinued operations based on the ratio of the assets sold to total Company net assets, excluding the known debt repayment. For the years ended December 31, 2009, 2008 and 2007, interest expense allocated to discontinued operations was $0 million, $4.7 million and $11.3 million, respectively.

Net assets associated with the divested IPP plants were as follows (in thousands):

	December 31, 2007
Current assets	$34,112
Property, plant and equipment, net of accumulated depreciation	485,286
Goodwill	18,095
Intangible assets (net of accumulated amortization of $27,363)	21,023
Other non-current assets	13,163
Current liabilities	(15,615)
Long-term debt	(73,928)
Other non-current liabilities	(139)
Net assets	$481,997

(23) ACQUISITIONS

Aquila Transaction

In February 2007, we entered into a definitive agreement with Aquila to acquire its regulated electric utility in Colorado and its regulated gas utilities in Colorado, Kansas, Nebraska and Iowa for $940 million, subject to customary closing adjustments. Based on working capital, capital expenditure and other adjustments, we paid $908.8 million in cash to Aquila and completed the acquisition on July 14, 2008. Additionally, approximately $29.6 million of fees and other costs were capitalized as part of the purchase price. The purchase price was financed through our Acquisition Facility and from cash proceeds generated from the IPP Transaction.

The acquisition of the Aquila assets has been accounted for under purchase accounting, whereby the purchase price of the transaction was allocated to identifiable assets acquired and liabilities assumed based upon their fair values. The estimates of the fair values recorded were determined based on accounting standards for fair value and reflect significant assumptions and judgments. We comply with the accounting standards for regulated operations and thus the assets and settlement of liabilities are subject to cost-based regulatory rate-setting processes. Accordingly, the historical carrying values of a majority of our assets and liabilities were deemed to represent fair values. In accordance with accounting standards for business combinations, adjustments to the purchase price allocation and subsequently goodwill occurred through July 14, 2009.

Adjustments to the purchase price allocation during 2009 included working capital and tax adjustments of $5.4 million. Allocation of the purchase price is as follows (in thousands):

Current assets	$113,486
Property, plant and equipment	542,094
Derivative assets	4,695
Goodwill(a)	339,028
Intangible assets(b)	4,884
Deferred assets	76,143
	$1,080,330
Current liabilities	$95,257
Deferred credits and other liabilities	54,550
	$149,807
Net assets	$930,523

(a) $245.1 million and $93.9 million of goodwill was allocated to the regulated Electric Utilities and to the regulated Gas Utilities, respectively. All of this goodwill is expected to be fully tax deductible.
(b) Intangible assets include $3.9 million of easements and right-of-ways and $1.0 million of trademark and trade names. This amount is being amortized on a straight-line basis over 20 years.

The results of operations of the acquired regulated utilities have been included in the accompanying Consolidated Financial Statements since the acquisition date.

The following unaudited pro-forma consolidated results of operations have been prepared as if the acquisition of the regulated utilities had occurred on January 1, 2008 and 2007, respectively (in thousands, except per share amounts):

	December 31, 2008	December 31, 2007
Operating revenues	$ 1,548,688	$ 1,389,838
Income (loss) from continuing operations	(27,640)	108,089
Net income	129,477	130,238
(Loss) earnings per share -		
Basic:		
Continuing operations	$ (0.73)	$ 2.92
Total	$ 3.39	$ 3.53
Diluted:		
Continuing operations	$ (0.73)	$ 2.89
Total	$ 3.39	$ 3.49

The above pro-forma information is presented for informational purposes only and is not necessarily indicative of the results of operations that would have been achieved had the acquisition been consummated at that time; nor is it intended to be a projection of future results.

(24) QUARTERLY HISTORICAL DATA (Unaudited)

The Company operates on a calendar year basis. The following tables set forth selected unaudited historical operating results and market data for each quarter of 2009 and 2008. All periods presented are adjusted to reflect the IPP Transaction as Discontinued operations.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2009				
Operating revenues	$437,943	$257,349	$225,799	$348,487
Operating income(a)	33,469	25,814	16,909	50,640
Income (loss) from continuing operations(a)(b)	25,625	24,581	(3,853)	32,403
Income from discontinued operations, net of taxes	766	-	1,673	360
Net income (loss) available for common stock	26,391	24,581	(2,180)	32,763
Earnings (loss) per common share:				
Basic -				
Continuing operations	$0.67	$0.64	$(0.10)	$0.83
Discontinued operations	0.02	-	0.04	0.01
Total	$0.69	$0.64	$(0.06)	$0.84
Diluted -				
Continuing operations	$0.66	$0.64	$(0.10)	$0.84
Discontinued operations	0.02	-	0.04	0.01
Total	$0.68	$0.64	$(0.06)	$0.85
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

(a) Includes ceiling test impairment of $43.3 million pre-tax ($27.8 million after tax) in first quarter.
(b) Includes unrealized mark-to-market income (loss) for interest rate swaps of $9.6 million, $20.6 million, $(5.6) million and $11.6 million after-tax in the first, second, third and fourth quarters, respectively.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2008				
Operating revenues	$152,850	$153,273	$291,892	$407,775
Operating income (loss)(a)	25,536	25,523	42,688	(37,870)
Income (loss) from continuing operations(a)(b)	11,816	13,203	19,522	(96,578)
Income (loss) from discontinued operations, net of taxes(c)	5,052	9,046	145,389	(2,240)
Non-controlling interest	(77)	(53)	-	-
Net income (loss) available for common stock	16,791	22,196	164,911	(98,818)
Earnings (loss) per common share:				
Basic -				
Continuing operations	$0.31	$0.34	$0.51	$(2.52)
Discontinued operations	0.13	0.24	3.79	(0.06)
Total	$0.44	$0.58	$4.30	$(2.58)
Diluted -				
Continuing operations	$0.31	$0.34	$0.51	$(2.52)
Discontinued operations	0.13	0.24	3.78	(0.06)
Total	$0.44	$0.58	$4.29	$(2.58)
Dividends paid per share	$0.35	$0.35	$0.35	$0.35
Common stock prices				
High	$43.98	$39.66	$39.23	$31.59
Low	$33.21	$31.70	$30.10	$21.73

(a) Includes ceiling test impairment of $91.8 million pre-tax ($59.0 million after-tax) in the fourth quarter.
(b) Includes unrealized mark-to-market charge for interest rate swaps of $61.4 million after-tax in the fourth quarter.
(c) Includes gain on the IPP Transaction of $139.7 million after-tax during the third quarter.

(25) SUBSEQUENT EVENTS

In February 2010, we provided notice to the bondholders of our intent to call the BHP Series Y bonds in full. These bonds were originally due in 2018. The balance of $2.5 million plus an early redemption premium of 2.6% will be paid on March 31, 2010.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure controls and procedures

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 (Exchange Act)) as of December 31, 2009. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

Internal control over financial reporting

Management's Report on Internal Control over Financial Reporting is presented on Page 128 of this Annual Report on Form 10-K.

During our fourth fiscal quarter, there have been no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding our directors and information required by Items 401, 405, 407(c)(3), 407(d)(4) and 407(d)(5) of Regulation S-K is incorporated herein by reference to the Proxy Statement for the Annual Shareholders' Meeting to be held May 25, 2010.

Our Board of Directors has adopted a Code of Ethics that applies to our Chief Executive Officer, Chief Financial Officer, Corporate Controller, and certain other persons performing similar functions. In addition, we have adopted Corporate Governance Guidelines for the Board of Directors, a Code of Business Conduct for our employees and Charters for the Audit, Compensation and Governance Committees of the Board of Directors. The current version of the documents can be found in the Corporate Governance section of our Web site, http://www.blackhillscorp.com/corpgov.htm, and a copy of these materials may be obtained without charge by contacting our Corporate Secretary. We intend to disclose any amendments to, or waivers of the Code of Ethics on behalf of our Chief Executive Officer, Chief Financial Officer, Corporate Controller, and persons performing similar functions, on our Internet website.

Information required by Item 401(b) of Regulation S-K is presented as Item 4A herein as permitted by General Instruction G(3) to Form 10-K and Instruction 3 to Item 401(b) of Regulation S-K.

ITEM 11. EXECUTIVE COMPENSATION

Information regarding executive compensation and transactions and compensation committee interlocks and insider participation is incorporated herein by reference to our Proxy Statement for the Annual Shareholders' Meeting to be held May 25, 2010.

The Compensation Committee Report is also incorporated herein by reference to our Proxy Statement, however it is deemed to be "furnished" and shall not be deemed to be "filed" for the purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933, except as shall be expressly set forth by specific reference in such filing.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information regarding the security ownership of certain beneficial owners and management is incorporated herein by reference to our Proxy Statement for the Annual Shareholders' Meeting to be held May 25, 2010.

EQUITY COMPENSATION PLAN INFORMATION

The following table includes information as of December 31, 2009 with respect to our equity compensation plans. These plans include the 1996 Stock Option Plan, the 1999 Stock Option Plan, the 2001 Omnibus Incentive Plan and the 2005 Omnibus Incentive Plan.

Equity Compensation Plan Information

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)		Weighted-average exercise price of outstanding options, warrants and rights (b)		Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)	
Equity compensation plans approved by security holders(1)	481,868	(2)	$ 32.24	(2)	751,996	(3)
Equity compensation plans not approved by security holders	-		-		-	
Total	481,868		$ 32.24		751,996	

(1) Consists of the 1996 Stock Option Plan, the 1999 Stock Option Plan, the 2001 Omnibus Incentive Plan and the 2005 Omnibus Incentive Plan.

(2) Includes 145,573 full value awards outstanding as of December 31, 2009, comprised of restricted stock units, performance shares and Director common stock units. The weighted average exercise price does not include the restricted stock units, performance shares or common stock units. In addition, 179,668 shares of unvested restricted stock were outstanding as of December 31, 2009, which are not included in the above table because they have already been issued.

(3) Shares available for issuance are from the 2005 Omnibus Incentive Plan. The 2005 Omnibus Incentive Plan permits the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards and other stock based awards.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information regarding certain relationships and related transactions and director independence is incorporated herein by reference to our Proxy Statement for the Annual Shareholders' Meeting to be held May 25, 2010.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information regarding principal accounting fees and services is incorporated herein by reference to our Proxy Statement for the Annual Shareholder's Meeting to be held May 25, 2010.

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PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) 1. Consolidated Financial Statements

Financial statements required under this item are included in Item 8 of Part II.

2. Schedules

Schedule I – Condensed Financial Information of the Registrant

Schedule II - Consolidated Valuation and Qualifying Accounts for the years ended December 31, 2009, 2008 and 2007.

All other schedules have been omitted because of the absence of the conditions under which they are required or because the required information is included in our consolidated financial statements and notes thereto.

SCHEDULE I

BLACK HILLS CORPORATION (PARENT COMPANY)
CONDENSED STATEMENTS OF INCOME

Years ended December 31,	2009	2008	2007
		(in thousands)	
Operating revenues	$-	$-	$-
Operating expenses	524	8,978	10,914
Operating loss	(524)	(8,978)	(10,914)
Other income (expense):			
Equity in earnings of subsidiaries	57,394	174,230	104,860
Interest expense	(17,786)	(1,604)	(430)
Interest rate swap	55,653	(94,440)	-
Interest income	10	153	422
Other income	28	10	8
Total other income (expense)	95,299	78,349	104,860
Income (loss) from continuing operations before income taxes	94,775	69,371	93,946
Income tax benefit (expense)	(13,025)	36,586	4,904
Income from continuing operations	81,750	105,957	98,850
Loss from discontinued operations	(195)	(877)	(78)
Net income	81,555	105,080	98,772
Net income (loss) attributable to non-controlling interest	-	-	-
Net income available for common stock	$81,555	$105,080	$98,772

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BLACK HILLS CORPORATION (PARENT COMPANY)
CONDENSED BALANCE SHEETS

At December 31,	2009	2008
ASSETS	(in thousands)	
Current assets:		
Cash	$2,273	$17,184
Accounts receivable – affiliates	2,226	49,556
Notes receivable – affiliates	160,160	360,463
Deferred income taxes	15,403	34,902
Other current assets	16,096	8,574
Total current assets	196,158	470,679
Investments in subsidiaries	1,101,240	1,278,702
Notes receivable long-term – affiliate	475,000	-
Deferred tax assets	14,501	20,595
Other long-term assets	500	1,960
Total other assets	490,001	22,555
TOTAL ASSETS	$1,787,399	$1,771,936
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$1,827	$29,302
Derivative liabilities, current	45,129	100,180
Notes payable	164,500	321,000
Notes payable – affiliate	-	20,959
Other current liabilities	7,130	2,592
Total current liabilities	218,586	474,033
Derivative liabilities, non-current	9,075	22,495
Long-term debt	474,901	224,872
Total stockholders' equity	1,084,837	1,050,536
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$1,787,399	$1,771,936

BLACK HILLS CORPORATION (PARENT COMPANY)
STATEMENTS OF CASH FLOWS

Years ended December 31,	2009	2008	2007
		(in thousands)	
Operating activities:			
Net income	$81,555	$105,080	$98,772
Loss from discontinued operations, net of tax	195	877	78
Income from continuing operations	81,750	105,957	98,850
Adjustments to reconcile income (loss) from continuing operations to net cash provided by operating activities -			
Equity in earnings of subsidiaries	(57,394)	(174,230)	(104,860)
Stock compensation	3,983	2,657	4,585
Unrealized mark-to-market (gain) loss on certain interest rate swaps	(55,653)	94,440	-
Derivative fair value adjustments	1,461	-	399
Deferred income taxes	19,224	(32,606)	(497)
Other non-cash adjustments	1,070	(926)	(6,946)
Change in operating assets and liabilities-			
Accounts receivable and other current assets	41,237	(33,342)	(7,313)
Accounts payable and other current liabilities	(22,906)	5,360	14,296
Other operating activities	-	20	-
Net cash provided by operating activities of continuing operations	12,772	(32,670)	(1,486)
Net cash used by operating activities of discontinued operations	(195)	(877)	(78)
Net cash provided by operating activities	12,577	(33,547)	(1,564)
Investing activities:			
Property, plant and equipment additions	-	-	(12,176)
(Increase) decrease in advances to affiliate	(115,731)	(189,524)	23,859
Other investing activities	-	(13,500)	-
Net cash used in investing activities of continuing operations	(115,731)	(203,024)	11,683
Net cash used in investing activities of discontinued operations	-	-	-
Net cash used in investing activities	(115,731)	(203,024)	11,683
Financing activities:			
Dividends paid on common stock	(55,151)	(53,663)	(50,300)
Common stock issued	4,819	2,683	150,787
Increase in short-term borrowings	(742,500)	(483,500)	(444,608)
Decrease in short-term borrowings	631,075	788,459	336,108
Long-term debt - issuance	248,500	-	-
Other financing activities	1,500	(2,066)	(713)
Net cash provided by financing activities of continuing operations	88,243	251,913	(8,726)
Net cash used in financing activities of discontinued operations	-	-	-
Net cash (used in) provided by financing activities	88,243	251,913	(8,726)
(Decrease) increase in cash and cash equivalents	(14,911)	15,342	1,393
Cash and cash equivalents:			
Beginning of year	17,184	1,842	449
End of year	$2,273	$17,184	$1,842

Supplemental Cash Flow Information

Years ended December 31,	2009	2008 (in thousands)	2007
Non-cash investing and financing activities-			
Non-cash adjustment to notes receivable from affiliate	$66,034	$34,473	$-
Non-cash dividend from affiliates	$225,000	$225,000	$-
Cash paid (received) during the period for-			
Interest	$19,878	$1,376	$(344)
Income taxes refunded	$(6,667)	$(2,278)	$(811)

NOTES TO CONDENSED FINANCIAL STATEMENTS

(1) BASIS OF PRESENTATION

Pursuant to rules and regulations of the SEC, the unconsolidated condensed financial statements of Black Hills Corporation do not reflect all of the information and notes normally included with financial statements prepared in accordance with GAAP. Therefore, these condensed financial statements should be read in conjunction with the consolidated financial statements and related notes included in this Annual Report on Form 10-K.

Non-cash dividends paid to Black Hills Corporation (the Parent) from its subsidiaries were $225.0 million, $225.0 million and $0 million during 2009, 2008 and 2007.

(2) NOTES PAYABLE

Black Hills Corporation had a committed line of credit with various banks totaling $525.0 million at December 31, 2009 and 2008, respectively. Our credit line is a revolving credit facility, which expires May 4, 2010. The lenders' commitments under this credit facility were increased from $400.0 million to $525.0 million in July 2008. We had $164.5 million of borrowings and $44.8 million of letters of credit and $321.0 million of borrowings and $60.7 million of letters of credit issued under the facility at December 31, 2009 and 2008, respectively. The cost of borrowings or letters of credit issued under the facility is determined based on our credit ratings. At our current ratings levels, the facility has an annual facility fee of 17.5 basis points, and has a borrowing spread of 70 basis points over LIBOR (which equates to a 0.93% one-month borrowing rate as of December 31, 2009). We have no compensating balance requirements associated with this credit facility.

(3) LONG-TERM DEBT

Long-term debt outstanding at December 31 is as follows (in thousands):

	2009	2008
Senior unsecured notes at 6.5% due 2013	$225,000	$225,000
Unamortized discount on notes due 2013	(99)	(128)
Senior unsecured notes at 9.0% due 2014	250,000	-
Total senior unsecured notes	$474,901	$224,872

Scheduled maturities of long-term debt, excluding amortization of premium or discount, for the next five years are: $225.0 million in 2013 and $250.0 million in 2014.

Certain debt instruments of the Company contain restrictions and covenants, all of which we were in compliance with at December 31, 2009.

(4) GUARANTEES

We have entered into various agreements providing financial or performance assurance to third parties on behalf of certain of our subsidiaries. The agreements include guarantees of debt obligations, contractual performance obligations and indemnification for reclamation and surety bonds.

As of December 31, 2009, we had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2009	Year Expiring
Guarantee obligations of Enserco under an agency agreement	$ 7,000	2010
Guarantees for payment obligations arising from commodity-related physical and financial transactions by Black Hills Utility Holdings	70,000	Ongoing
Guarantees for payment obligations arising from purchase contracts for four gas turbines for Black Hills Colorado IPP	62,090	2011
Guarantees for payment obligations arising from purchase contracts for two gas turbines for Colorado Electric	42,742	2010
Indemnification for subsidiary reclamation/surety bonds	15,532	Ongoing
	$ 197,364	

(5) RISK MANAGEMENT ACTIVITIES

We engage in activities to manage risks associated with changes in interest rates. We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations.

- At December 31, 2009, we have $150.0 million of notional amount floating-to-fixed interest rate swaps designated as cash flow hedges in accordance with accounting guidance for derivatives and accordingly, the mark-to-market adjustments are recorded in Accumulated other comprehensive loss on the Condensed Balance Sheets of this Schedule I. The swaps have a maximum term of seven years.

- We also have interest rate swaps with a notional amount of $250.0 million which were entered into for the purpose of hedging interest rate movements that would impact long-term financings that were originally expected to occur in 2008. The swaps were originally designated as cash flow hedges in accordance with accounting guidance for derivatives and the mark-to-market values were recorded in Accumulated other comprehensive loss on the Consolidated Balance Sheets. Based on credit market conditions that transpired during the fourth quarter of 2008, we determined it was probable that the forecasted long-term debt financings would not occur in the time period originally specified and as a result, the swaps were no longer effective hedges and the hedge relationships were de-designated. Mark-to-market adjustments on the swaps are now recorded within the income statement and during 2009 we recorded a $55.7 million pre-tax unrealized mark-to-market gain to earnings, while in 2008 we recorded a $94.4 million pre-tax unrealized mark-to-market charge to earnings. These swaps are nine and nineteen year swaps which have amended mandatory early termination dates ranging from December 15, 2010 to December 29, 2010.

On December 31, 2009 and 2008, our interest rate swaps and related balances were as follows (dollars in thousands):

	December 31, 2009		December 31, 2008	
	Interest Rate Swaps	Dedesignated Interest Rate Swaps	Interest Rate Swaps	Dedesignated Interest Rate Swaps
Notional	$150,000	$ 250,000	$150,000	$ 250,000
Weighted average fixed interest rate	5.04 %	5.67 %	5.04 %	5.67 %
Maximum terms in years	7.0	1.0	8.00	1.00
Current derivative assets	$-	$ -	$-	$ -
Non-current derivative assets	$-	$ -	$-	$ -
Current derivative liabilities	$6,342	$ 38,787	$5,740	$ 94,440
Non-current derivative liabilities	$9,075	$ -	$22,495	$ -
Pre-tax accumulated other comprehensive (loss)	$(15,417)	$ -	$(28,235)	$ -
Pre-tax gain (loss)	$-	$ 55,653	$-	$ (94,440)

Based on December 31, 2009 market interest rates and balances, a loss of approximately $6.3 million would be realized and reported in pre-tax earnings during the next twelve months. Estimated and realized losses will change during the next twelve months as market interest rates fluctuate.

(6) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments at December 31, are as follows (in thousands):

	2009		2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash	$2,273	$2,273	$17,184	$17,184
Derivative financial instruments - liabilities	$54,204	$54,204	$122,675	$122,675
Notes payable	$164,500	$164,500	$321,000	$321,000
Long-term debt	$474,901	$524,673	$224,872	$200,250

Derivative Financial Instruments

These instruments are carried at fair value. Additional descriptions of these instruments are included in Note 5 of these Condensed Parent Company Financial Statements on Schedule I.

Notes Payable

The carrying amount approximates fair value due to their variable interest rates with short reset periods.

Long-Term Debt

The fair value of our long-term debt is estimated based on quoted market rates for debt instruments having similar maturities and similar debt ratings.

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(7) COMMITMENTS AND CONTINGENCIES

The Company is subject to various legal proceedings, claims and litigation which arise in the ordinary course of operations. In the opinion of management, the amount of liability, if any, with respect to these actions would not materially affect the financial position, results of operations or cash flows of the Company.

SCHEDULE II

BLACK HILLS CORPORATION
CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DECEMBER 31, 2009, 2008 AND 2007

Description	Balance at Beginning of Year	Adjustments(a)	Additions Charged to Costs and Expenses	Other Additions(b)	Deductions(c)	Balance at End of Year
			(in thousands)			
Allowance for doubtful accounts:						
2009	$6,751	$ -	$3,428	$ 3,229	$ (8,787)	$4,621
2008	4,588	3,910	3,262	1,789	(6,798)	6,751
2007	4,202	-	2,896	354	(2,864)	4,588

(a) Opening balance of assets acquired in the Aquila Transaction
(b) Recoveries
(c) Uncollectible accounts written off

3. Exhibits

Exhibit Number	Description
3.1*	Restated Articles of Incorporation of the Registrant (filed as Exhibit 3 to the Registrant's Form 10-K for 2004).
3.2*	Amended and Restated Bylaws of the Registrant dated January 28, 2010 (filed as Exhibit 3 to the Registrant's Form 8-K filed February 3, 2010).
4.1*	Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to LaSalle Bank National Association), as Trustee (filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant's Form 8-K filed on May 14, 2009).
4.2*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant's Post-Effective Amendment No. 1 to the Registrant’s Registration Statement on Form S-3 (No. 333-150669)). Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant's Post-Effective Amendment No. 2 to the Registrant’s Registration Statement on Form S-3 (No. 333-150669).
4.3*	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000).
10.1*†	Amended and Restated Pension Equalization Plan of Black Hills Corporation dated November 6, 2001 (filed as Exhibit 10.11 to the Registrant's Form 10-K/A for 2001). First Amendment to Pension Equalization Plan (filed as Exhibit 10.10 to the Registrant's Form 10-K for 2002). Grandfather Amendment to the Amended and Restated Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.2 to the Registrant's Form 10-K for 2008).
10.2*†	2005 Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.3 to the Registrant's Form 10-K for 2008).
10.3*†	2007 Pension Equalization Plan of Black Hills Corporation as Amended and Restated effective January 1, 2009 (filed as Exhibit 10.4 to the Registrant's Form 10-K for 2008).
10.4*†	

	Restoration Plan of Black Hills Corporation (filed as Exhibit 10.5 to the Registrant's Form 10-K for 2008).
10.5†	Black Hills Corporation Non-qualified Deferred Compensation Plan as Amended and Restated effective January 1, 2010.

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10.6*†	Black Hills Corporation 2005 Omnibus Incentive Plan (filed as Appendix A to the Registrant's Proxy Statement filed April 13, 2005). First Amendment to the Black Hills Corporation 2005 Omnibus Incentive Plan (filed as Exhibit 10.11 to the Registrant's Form 10-K for 2008).
10.7*†	Form of Stock Option Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on July 11, 2005). Form of Stock Option Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after January 1, 2009 (filed as Exhibit 10.13 to the Registrant's Form 10-K for 2008).
10.8*†	Form of Restricted Stock Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after December 10, 2007 (filed as Exhibit 10.13 to the Registrant's Form 10-K for 2007). Form of Restricted Stock Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after January 1, 2009 (filed as Exhibit 10.15 to the Registrant's Form 10-K for 2008).
10.9*†	Form of Restricted Stock Unit Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after January 1, 2009 (filed as Exhibit 10.17 to the Registrant's Form 10-K for 2008).
10.10*†	Form of Performance Share Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after December 10, 2007 (filed as Exhibit 10.17 to the Registrant's Form 10-K for 2007). Form of Performance Share Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after January 1, 2009 (filed as Exhibit 10.19 to the Registrant's Form 10-K for 2008).
10.11†	Form of Performance Share Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after January 1, 2010.
10.12†	Form of Short-Term Incentive for 2005 Omnibus Incentive Plan effective for awards granted on or after January 1, 2010.
10.13*†	Form of Indemnification Agreement (filed as Exhibit 10.5 to the Registrant's Form 8-K filed on September 3, 2004).
10.14*†	Change in Control Agreement dated June 1, 2008 between Black Hills Corporation and David R. Emery (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on June 5, 2008).
10.15*†	Form of Change in Control Agreements between Black Hills Corporation and its non-CEO Senior Executive Officers (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on June 5, 2008).
10.16*†	Outside Directors Stock Based Compensation Plan as Amended and Restated effective January 1, 2009 (filed as Exhibit 10.23 to the Registrant's Form 10-K for 2008).

10.17* Credit Agreement, dated as of May 5, 2005 among Black Hills Corporation, as Borrower, the financial institutions from time to time party thereto as Banks, US Bank, National Association, as Co-Syndication Agent, Union Bank of California, N.A., as Co-Syndication Agent, BANK OF AMERICA, N.A., as Co-Documentation Agent, BANK OF MONTREAL dba HARRIS NESBITT, as Co-Documentation Agent, and ABN AMRO Bank N.V. as Administrative Agent ("BHC Credit Agreement") (filed as Exhibit 10.1 to the Registrant's Form 10-Q for March 31, 2005). First Amendment to the BHC Credit Agreement, dated as of May 12, 2006 (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on March 19, 2007). Second Amendment to the BHC Credit Agreement, dated as of March 13, 2007 (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on March 19, 2007). Third Amendment to the BHC Credit Agreement dated as of July 10, 2008 (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on July 14, 2008).

10.18* Third Amended and Restated Credit Agreement effective May 8, 2009, among Enserco Energy Inc., as borrower, Fortis Capital Corp., as administrative agent and collateral agent, Societe Generale as Syndication Agent, BNP Paribas as documentation agent, U.S. Bank National Association, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and the other financial institutions which may become parties thereto ("Enserco Credit Agreement") (filed as Exhibit 10.1 to the Registrant's Form 8-K filed October 20, 2009). Joinder Agreements dated May 27, 2009 to the Enserco Credit Agreement (filed as Exhibits 10.1, 10.2 and 10.3 to the Registrant's Form 8-K filed on May 28, 2009). First Amendment to the Enserco Credit Agreement effective August 25, 2009 (filed as Exhibit 10 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2009).

10.19 Second Amendment to the Enserco Credit Agreement effective December 30, 2009.

10.20* Purchase and Sale Agreement by and between Black Hills Generation, Inc., as Seller, and Southwest Generation Operating Company, LLC, as Buyer, dated as of April 29, 2008 (filed as Exhibit 10 to the Registrant's Form 8-K filed on May 1, 2008).

10.21* Coal Leases between WRDC and the Federal Government
-Dated May 1, 1959 (filed as Exhibit 5(i) to the Registrant's Form S-7, File No. 2-60755)
-Modified January 22, 1990 (filed as Exhibit 10(h) to the Registrant's Form 10-K for 1989)
-Dated April 1, 1961 (filed as Exhibit 5(j) to the Registrant's Form S-7, File No. 2-60755)
-Modified January 22, 1990 (filed as Exhibit 10(i) to Registrant's Form 10-K for 1989)
-Dated October 1, 1965 (filed as Exhibit 5(k) to the Registrant's Form S-7, File No. 2-60755)
-Modified January 22, 1990 (filed as Exhibit 10(j) to the Registrant's Form 10-K for 1989).

10.22* Assignment of Mining Leases and Related Agreement effective May 27, 1997, between WRDC and Kerr-McGee Coal Corporation (filed as Exhibit 10(u) to the Registrant's Form 10-K for 1997).

21	List of Subsidiaries of Black Hills Corporation.
23.1	Independent Auditors' Consent.
23.2	Consent of Petroleum Engineer and Geologist.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.

32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99	Report of Cawley, Gillespie & Associates, Inc.

* Previously filed as part of the filing indicated and incorporated by reference herein.

† Indicates a board of director or management compensatory plan.

(b) See (a) 3. Exhibits above.

(c) See (a) 2. Schedules above.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BLACK HILLS CORPORATION

By: /S/ DAVID R. EMERY
David R. Emery, Chairman, President
and Chief Executive Officer

Dated: February 26, 2010

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/S/ DAVID R. EMERY David R. Emery, Chairman, President and Chief Executive Officer	Director and Principal Executive Officer	February 26, 2010
/S/ ANTHONY S. CLEBERG Anthony S. Cleberg, Executive Vice President and Chief Financial Officer	Principal Financial and Accounting Officer	February 26, 2010
/S/ DAVID C. EBERTZ David C. Ebertz	Director	February 26, 2010
/S/ JACK W. EUGSTER Jack W. Eugster	Director	February 26, 2010
/S/ JOHN R. HOWARD John R. Howard	Director	February 26, 2010
/S/ KAY S. JORGENSEN Kay S. Jorgensen	Director	February 26, 2010
/S/ STEPHEN D. NEWLIN Stephen D. Newlin	Director	February 26, 2010
/S/ GARY L. PECHOTA Gary L. Pechota	Director	February 26, 2010
/S/ WARREN L. ROBINSON	Director	February 26, 2010

Warren L. Robinson

/S/ JOHN B. VERING John B. Vering	Director	February 26, 2010
/S/ THOMAS J. ZELLER Thomas J. Zeller	Director	February 26, 2010

INDEX TO EXHIBITS

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3.2*	Amended and Restated Bylaws of the Registrant dated January 28, 2010 (filed as Exhibit 3 to the Registrant's Form 8-K filed February 3, 2010).
4.1*	Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to LaSalle Bank National Association), as Trustee (filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant's Form 8-K filed on May 14, 2009).
4.2*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant's Post-Effective Amendment No. 1 to the Registrant’s Registration Statement on Form S-3 (No. 333-150669)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant's Post-Effective Amendment No. 1 to the Registrant’s Registration Statement on Form S-3 (No. 333-150669)). Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant's Post-Effective Amendment No. 2 to the Registrant’s Registration Statement on Form S-3 (No. 333-150669).
4.3*	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000).
10.1*†	Amended and Restated Pension Equalization Plan of Black Hills Corporation dated November 6, 2001 (filed as Exhibit 10.11 to the Registrant's Form 10-K/A for 2001). First Amendment to Pension Equalization Plan (filed as Exhibit 10.10 to the Registrant's Form 10-K for 2002). Grandfather Amendment to the Amended and Restated Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.2 to the Registrant's Form 10-K for 2008).
10.2*†	

	2005 Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.3 to the Registrant's Form 10-K for 2008).
10.3*†	2007 Pension Equalization Plan of Black Hills Corporation as Amended and Restated effective January 1, 2009 (filed as Exhibit 10.4 to the Registrant's Form 10-K for 2008).

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10.4*†	Restoration Plan of Black Hills Corporation (filed as Exhibit 10.5 to the Registrant's Form 10-K for 2008).
10.5†	Black Hills Corporation Non-qualified Deferred Compensation Plan as Amended and Restated effective January 1, 2010.
10.6*†	Black Hills Corporation 2005 Omnibus Incentive Plan (filed as Appendix A to the Registrant's Proxy Statement filed April 13, 2005). First Amendment to the Black Hills Corporation 2005 Omnibus Incentive Plan (filed as Exhibit 10.11 to the Registrant's Form 10-K for 2008).
10.7*†	Form of Stock Option Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on July 11, 2005). Form of Stock Option Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after January 1, 2009 (filed as Exhibit 10.13 to the Registrant's Form 10-K for 2008).
10.8*†	Form of Restricted Stock Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after December 10, 2007 (filed as Exhibit 10.13 to the Registrant's Form 10-K for 2007). Form of Restricted Stock Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after January 1, 2009 (filed as Exhibit 10.15 to the Registrant's Form 10-K for 2008).
10.9*†	Form of Restricted Stock Unit Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after January 1, 2009 (filed as Exhibit 10.17 to the Registrant's Form 10-K for 2008).
10.10*†	Form of Performance Share Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after December 10, 2007 (filed as Exhibit 10.17 to the Registrant's Form 10-K for 2007). Form of Performance Share Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after January 1, 2009 (filed as Exhibit 10.19 to the Registrant's Form 10-K for 2008).
10.11†	Form of Performance Share Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after January 1, 2010.
10.12†	Form of Short-Term Incentive for 2005 Omnibus Incentive Plan effective for awards granted on or after January 1, 2010.
10.13*†	Form of Indemnification Agreement (filed as Exhibit 10.5 to the Registrant's Form 8-K filed on September 3, 2004).
10.14*†	

Change in Control Agreement dated June 1, 2008 between Black Hills Corporation and David R. Emery (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on June 5, 2008).

10.15*†	Form of Change in Control Agreements between Black Hills Corporation and its non-CEO Senior Executive Officers (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on June 5, 2008).
10.16*†	Outside Directors Stock Based Compensation Plan as Amended and Restated effective January 1, 2009 (filed as Exhibit 10.23 to the Registrant's Form 10-K for 2008).
10.17*	Credit Agreement, dated as of May 5, 2005 among Black Hills Corporation, as Borrower, the financial institutions from time to time party thereto as Banks, US Bank, National Association, as Co-Syndication Agent, Union Bank of California, N.A., as Co-Syndication Agent, BANK OF AMERICA, N.A., as Co-Documentation Agent, BANK OF MONTREAL dba HARRIS NESBITT, as Co-Documentation Agent, and ABN AMRO Bank N.V. as Administrative Agent ("BHC Credit Agreement") (filed as Exhibit 10.1 to the Registrant's Form 10-Q for March 31, 2005). First Amendment to the BHC Credit Agreement, dated as of May 12, 2006 (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on March 19, 2007). Second Amendment to the BHC Credit Agreement, dated as of March 13, 2007 (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on March 19, 2007). Third Amendment to the BHC Credit Agreement dated as of July 10, 2008 (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on July 14, 2008).
10.18*	Third Amended and Restated Credit Agreement effective May 8, 2009, among Enserco Energy Inc., as borrower, Fortis Capital Corp., as administrative agent and collateral agent, Societe Generale as Syndication Agent, BNP Paribas as documentation agent, U.S. Bank National Association, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and the other financial institutions which may become parties thereto ("Enserco Credit Agreement") (filed as Exhibit 10.1 to the Registrant's Form 8-K filed October 20, 2009). Joinder Agreements dated May 27, 2009 to the Enserco Credit Agreement (filed as Exhibits 10.1, 10.2 and 10.3 to the Registrant’s Form 8-K filed on May 28, 2009), First Amendment to the Enserco Credit Agreement effective August 25, 2009 (filed as Exhibit 10 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2009).
10.19	Second Amendment to the Enserco Credit Agreement effective December 30, 2009.
10.20*	Purchase and Sale Agreement by and between Black Hills Generation, Inc., as Seller, and Southwest Generation Operating Company, LLC, as Buyer, dated as of April 29, 2008 (filed as Exhibit 10 to the Registrant's Form 8-K filed on May 1, 2008).

10.21*	Coal Leases between WRDC and the Federal Government -Dated May 1, 1959 (filed as Exhibit 5(i) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(h) to the Registrant's Form 10-K for 1989) -Dated April 1, 1961 (filed as Exhibit 5(j) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(i) to Registrant's Form 10-K for 1989) -Dated October 1, 1965 (filed as Exhibit 5(k) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(j) to the Registrant's Form 10-K for 1989).
10.22*	Assignment of Mining Leases and Related Agreement effective May 27, 1997, between WRDC and Kerr-McGee Coal Corporation (filed as Exhibit 10(u) to the Registrant's Form 10-K for 1997).
21	List of Subsidiaries of Black Hills Corporation.
23.1	Independent Auditors' Consent.
23.2	Consent of Petroleum Engineer and Geologist.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99	Report of Cawley, Gillespie & Associates, Inc.

* Previously filed as part of the filing indicated and incorporated by reference herein.

† Indicates a board of director or management compensatory plan.